



2021 Electricity Statement of Opportunities

June 2021

A report for the Wholesale Electricity Market

Important notice

PURPOSE

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VERSION CONTROL

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#1	17/6/2021	Initial release

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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 consumption¹ forecasts across a range of weather and demand growth scenarios for the 2021-22 to 2030-31 Capacity Years² (outlook period).

The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM), which ensures sufficient capacity is available to meet the Planning Criterion³ for the SWIS. The primary purpose of the 2021 WEM ESOO is to determine the Reserve Capacity Requirement (RCR)⁴ for the 2023-24 Capacity Year, which is based on the 10% probability of exceedance (POE)⁵ peak demand⁶ forecast under the expected demand growth scenario⁷.

Key findings

- Based on the 10% POE peak demand forecast, the RCR has been determined as 4,396 megawatts (MW) for the 2023-24 Capacity Year.
- Assuming no other capacity changes, sufficient capacity is expected to be available to meet forecast demand over the outlook period despite the staged retirement of Muja C unit 5 (195 MW) in 2022 and Muja C unit 6 (193 MW) in 2024.
- Behind-the-meter photovoltaic (PV) capacity is forecast to grow at an average annual rate of 8.0% (219 MW per year) to reach an estimated 4,069 MW⁸ installed by the end of the outlook period.
- The 10% POE peak demand is forecast to grow at an average annual rate of 0.2% over the outlook period, compared to an average annual decline of 0.2% forecast in the 2020 WEM ESOO. Demand is expected to grow over the outlook period due to increased business activity and growth in residential connections, despite the continued uptake of behind-the-meter PV⁹.

¹ Operational demand (and operational consumption) refers to electricity demand (and consumption) that is met by all utility-scale generation and excludes the impacts of behind-the-meter PV generation and battery storage. Operational consumption includes demand (and consumption) from electric vehicles (EVs).

² A Capacity Year commences in Trading Interval 08:00 on 1 October and ends in Trading Interval 07:30 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 expected unserved energy to 0.002% of annual energy consumption (including transmission losses) for each Capacity Year of a 10-year forecast period.

⁴ The RCR is AEMO's determination of the total amount of capacity required to satisfy the Planning Criterion for a specific Reserve Capacity Cycle.

⁵ POE is 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.

⁶ Peak demand is operational demand unless otherwise specified in this WEM ESOO.

⁷ This 2021 WEM ESOO provides low, expected, and high demand growth scenarios based on different levels of economic growth as defined in clause 4.5.10 of the WEM Rules. Unless otherwise indicated, demand forecasts in this executive summary are based on the expected demand growth scenario.

⁸ This value includes degradation of behind-the-meter PV capacity. Consumption and demand forecasts in this WEM ESOO account for degradation of solar panel output over time. See Chapters 4 and 5 of this WEM ESOO for further information.

⁹ 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 that does not hold Capacity Credits in the WEM.

- Consistent with the 2020 WEM ESOO, AEMO anticipates that by 2023-24 peak demand is expected to shift 30 minutes later, from the period between 17:30 and 18:30 to between 18:00 and 19:00, due to the effect of distributed energy resources (DER)¹⁰.
- Operational consumption is forecast to decline at an average annual rate of 0.8% over the outlook period, marginally higher than the forecast decline of 0.4% in the 2020 WEM ESOO.
- Minimum demand is expected to decline rapidly to 232 MW¹¹ by 2025-26, predominantly due to growth in behind-the-meter PV installations; the record to date is 954 MW on 14 March 2021.

Reserve Capacity Requirement and pricing

The Reserve Capacity Target (RCT) determined for the 2023-24 Capacity Year is 4,396 MW, which sets the RCR for the 2021 Reserve Capacity Cycle. The RCT set by the expected 10% POE peak demand requirement of the Planning Criterion for each Capacity Year of the 2021 Long Term PASA Study Horizon is shown in Table 1.

Table 1 Reserve Capacity Targets^A (MW)

Capacity Year	10% POE peak demand	Intermittent loads ^B	Reserve margin ^C	Load following ^D	Total
2021-22 ^E	3,917	3	331	105	4,356
2022-23 ^E	3,937	3	335	105	4,380
2023-24	3,953	3	335	105	4,396
2024-25	3,966	3	335	105	4,409
2025-26	3,967	3	335	105	4,410
2026-27	3,984	3	335	105	4,427
2027-28	3,989	3	335	105	4,432
2028-29	3,998	3	335	105	4,441
2029-30	4,001	3	335	105	4,444
2030-31	4,000	3	335	105	4,443

A. All figures have been rounded to the nearest MW.

B. An estimate of the capacity required to cover the forecast cumulative needs of Intermittent Loads, which are excluded from the 10% POE expected peak demand forecast.

C. Calculated as the greater of 7.6% of the sum of the 10% POE forecast peak demand plus the Intermittent Load allowance and the maximum sent out capacity (measured at 41°C) of the largest generating unit.

D. Since the 2020 WEM ESOO, the Economic Regulation Authority has approved AEMO's proposed Load Following Ancillary Service (LFAS) requirements for the 2020-21 Financial Year (105 MW between 05:30-19:30 and 80 MW between 19:30-05:30). In calculating the RCT above, AEMO has assumed no change to this LFAS requirement over the outlook period.

E. Figures have been updated to reflect the current forecasts. However, the RCR of 4,482 MW set in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle and the RCR of 4,421 MW set in the 2020 WEM ESOO for the 2020 Reserve Capacity Cycle do not change.

Excess capacity¹² is forecast to increase slightly, from 386 MW (8.7%) for the 2022-23 Capacity Year to 411 MW (9.4%) for the 2023-24 Capacity Year. This is largely due to lower forecast peak demand¹³, partially offset by increased requirements for the reserve margin and Load Following. Excess capacity is forecast to fall

¹⁰ DER means small-scale embedded technologies including behind-the-meter PV, battery storage, and electric vehicles (EVs).

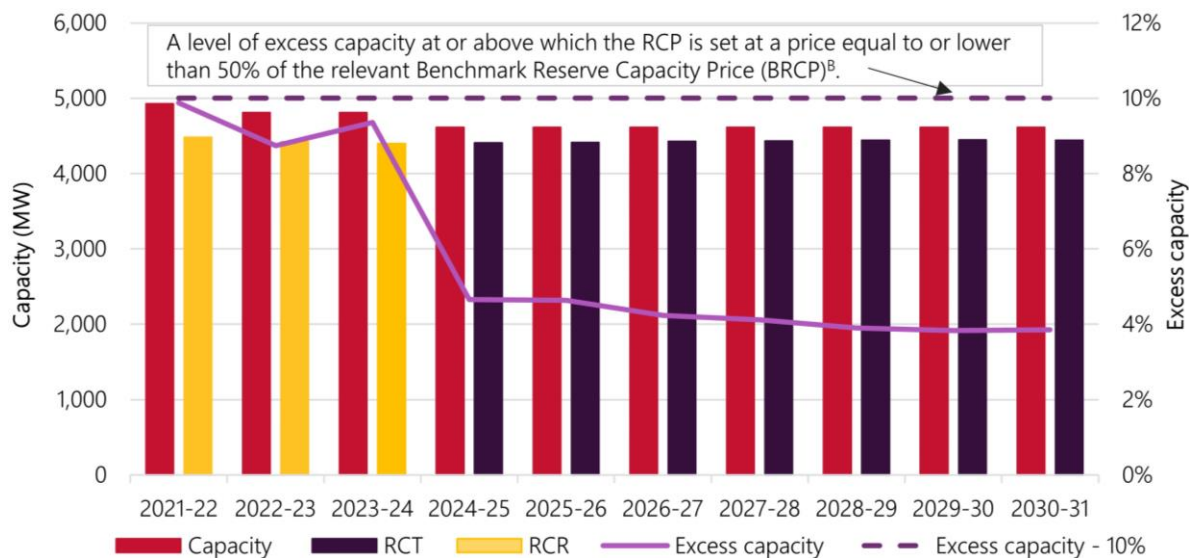
¹¹ Based on the 50% POE for the expected demand growth scenario.

¹² Excess capacity is calculated as: (Available capacity - RCR or RCT)/(RCR or RCT). For the 2021-22 and 2022-23 Capacity Years, available capacity is the total quantity of Capacity Credits assigned, for the 2023-24 to 2030-31 Capacity Years, available capacity is the forecast quantity of Reserve Capacity.

¹³ The 10% POE peak demand that set the RCR for the 2022-23 Capacity Year was calculated as 4,002 MW in the 2020 WEM ESOO.

to 205 MW (4.7%) in the 2024-25 Capacity Year, following the retirement of Muja C unit 6 from 1 October 2024¹⁴. Assuming no other capacity changes, excess capacity is expected to decline for the remainder of the outlook period to 171 MW (3.9%) in the 2030-31 Capacity Year, driven by limited growth in peak demand.

Figure 1 Reserve Capacity supply-demand balance, 2021-22 to 2030-31^{A,B}



A. The 2021-22 and 2022-23 available capacity values are actuals, while the remaining years are forecasts, as Capacity Credits have not yet been assigned for this period.

B. The BRCP represents the marginal cost of providing one additional 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 2022-23 Capacity Year, the Reserve Capacity Price (RCP) is \$85,294 per MW per year and Transitional Facilities will receive an RCP of \$115,425 per MW per year¹⁵. There are no Fixed Price Facilities for the 2022-23 Capacity Year.

The RCPs for all Facilities for the 2023-24 Capacity Year will be determined once Capacity Credits have been assigned for the 2021 Reserve Capacity Cycle¹⁶.

Peak demand and operational consumption forecasts

AEMO forecasts the 10% POE peak demand to increase from 3,917 MW in 2021-22 to 4,000 MW in 2030-31, at an average annual rate of 0.2% over the outlook period (see Table 2). The COVID-19 pandemic has had a limited effect on WA's economy and the peak demand forecast reflects a more optimistic outlook compared with the 2020 WEM ESOO, with some uplift coming from increased business activity and new residential connections.

Operational consumption forecasts for the low, expected, and high demand growth scenarios are shown in Table 3. These forecasts mainly reflect different assumptions about economic growth, behind-the-meter PV, electric vehicle (EV) uptake, energy efficiency improvements, new large industrial loads, and growth in the number of connections.

Operational consumption is forecast to fall at an average annual rate of 0.8% over the outlook period, marginally higher than the forecast decline of 0.4% in the 2020 WEM ESOO. This change is largely attributed to a significant increase in the behind-the-meter PV forecasts. Continued uptake of behind-the-meter PV and

¹⁴ Government of Western Australia, 2019. Muja Power Station in Collie to be scaled back from 2022. Media Release, 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 AEMO, 2021. Reserve Capacity Price, at <https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price>.

¹⁶ The 2021 Reserve Capacity Cycle timetable can be found at <http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable>.

energy efficiency improvements are expected to reduce operational consumption throughout the outlook period.

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

Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	5-year average annual growth	2030-31	10-year average annual growth
10% POE	3,917	3,937	3,953	3,966	3,967	0.3%	4,000	0.2%
50% POE	3,686	3,708	3,733	3,736	3,739	0.4%	3,772	0.3%
90% POE	3,476	3,507	3,516	3,527	3,530	0.4%	3,554	0.2%

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

Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	5-year average annual growth	2030-31	10-year average annual growth
Low	15,987	15,266	14,660	14,118	13,719	-3.8%	12,645	-2.6%
Expected	17,127	17,019	16,842	16,667	16,522	-0.9%	15,987	-0.8%
High	17,963	18,069	17,825	17,496	17,219	-1.1%	18,435	0.3%

For the 2020 WEM ESOO, the expected scenario DER forecasts were applied to the operational consumption and peak demand forecasts for all three economic growth scenarios. However, in the 2021 WEM ESOO, each economic growth scenario used different DER forecasts to better illustrate a wider range of outcomes, particularly on minimum demand. The DER forecasts under the high scenario assume more rapid economic growth and strong government support¹⁷ compared to the expected scenario, which results in a higher DER installation rate.

AEMO expects long-term temperature trends to have a significant impact on peak demand. Ongoing evidence from the Bureau of Meteorology (BOM) suggests continued changes in Australia’s climate¹⁸, and AEMO will continue to monitor the effects of climate on peak demand. AEMO’s forecasts leverage climate change modelling developed in collaboration with BOM and the Commonwealth Scientific and Industrial Research Organisation (CSIRO)¹⁹.

Trends in observed demand extremes and the impact of behind-the-meter PV

AEMO expects the strong growth of behind-the-meter PV capacity in the SWIS to continue, from 1,740 MW²⁰ to an expected 4,069 MW²¹ by the end of the outlook period (see Figure 2). Technological, commercial, and regulatory factors, as well as increasing environmental awareness, are expected to drive this uptake.

¹⁷ The approach was applied previously due to the observation that DER uptake was linked to payback period rather than macroeconomic drivers, which may have underestimated the effect of government policy during favourable economic conditions.

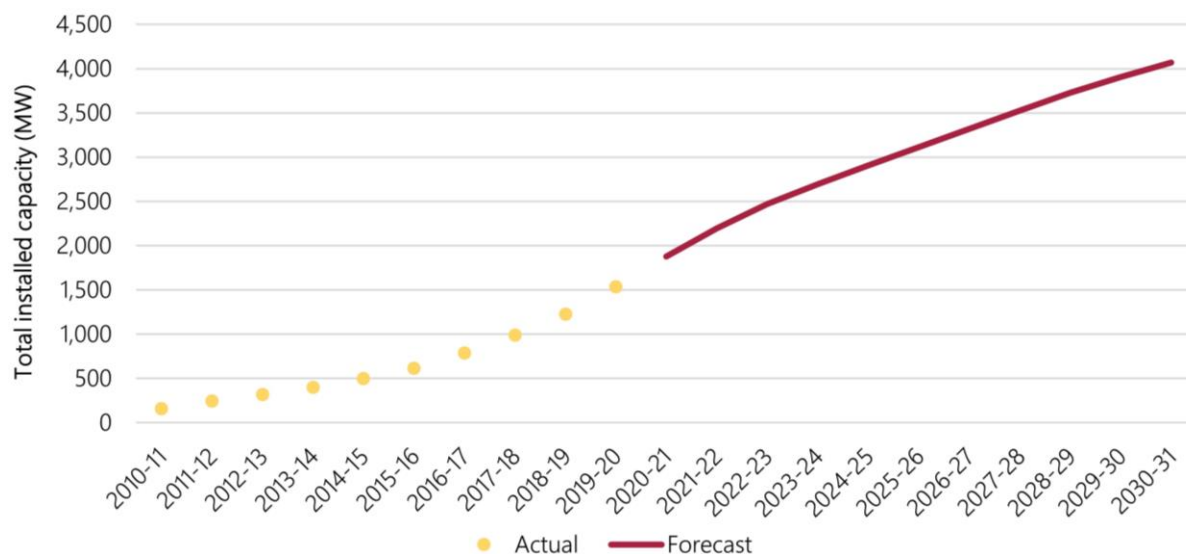
¹⁸ BOM 2020, *State of the Climate 2020*, Australian Government, at <http://www.bom.gov.au/state-of-the-climate/documents/State-of-the-Climite-2020.pdf>.

¹⁹ See Appendix A2, *Electricity Demand Forecasting Methodology Information Paper*, August 2020.

²⁰ Installation figures are provided by the Clean Energy Regulator (CER) with minor adjustments made by AEMO (as of April 2021) combined with AEMO estimates of commercial PV installations ranging between 100 kW and 10 MW that do not hold Capacity Credits in the WEM. Under the expected demand growth scenario behind-the-meter PV is forecast to be 1,877 MW by the end of the 2020-21 Capacity Year.

²¹ Forecast installed capacity of behind-the-meter PV as at October 2031 accounting for panel degradation.

Figure 2 Actual²⁰ and forecast total installed behind-the-meter PV, 2010-11 to 2030-31



Source: CER, CSIRO and GEM.

The growth in behind-the-meter PV capacity has three major impacts:

- Slowing the growth in operational peak demand.
 - For example, the 2020-21 summer period saw the highest estimated underlying demand²² (4,170 MW on 8 January 2021) since the WEM commenced in 2006 (see Figure 3). On this peak demand day, behind-the-meter PV generation is estimated to have reduced the peak by 381 MW, resulting in an operational peak demand of 3,789 MW.
- Shifting the operational peak demand to later in the day.
 - The likely timing of peak demand is expected to shift 30 minutes later, from the period between 17:30 and 18:30 to between 18:00 and 19:00 by 2023-24, due to the high uptake of behind-the-meter PV. The 2020-21 peak demand day typifies this; the peak was delayed from 14:00 to 14:30 to 18:00 to 18:30.
- Reducing operational minimum demand.
 - The WEM minimum demand record has been broken six times²³ since the 2020 WEM ESOO. The most recent record of 954 MW was observed during 11:30 to 12:00 on 14 March 2021. Behind-the-meter PV generation in this interval was approximately 1,130 MW.

Operational minimum demand events can result in large synchronous generation units not being dispatched, which can lead to a reduction in system security services. AEMO is currently using real-time monitoring²⁴ to ensure system security requirements are met.

Additionally, these operational challenges are being addressed through the Delivering the Future Power System and the DER workstreams being developed as part of the WA Government’s Energy Transformation Strategy (ETS)²⁵.

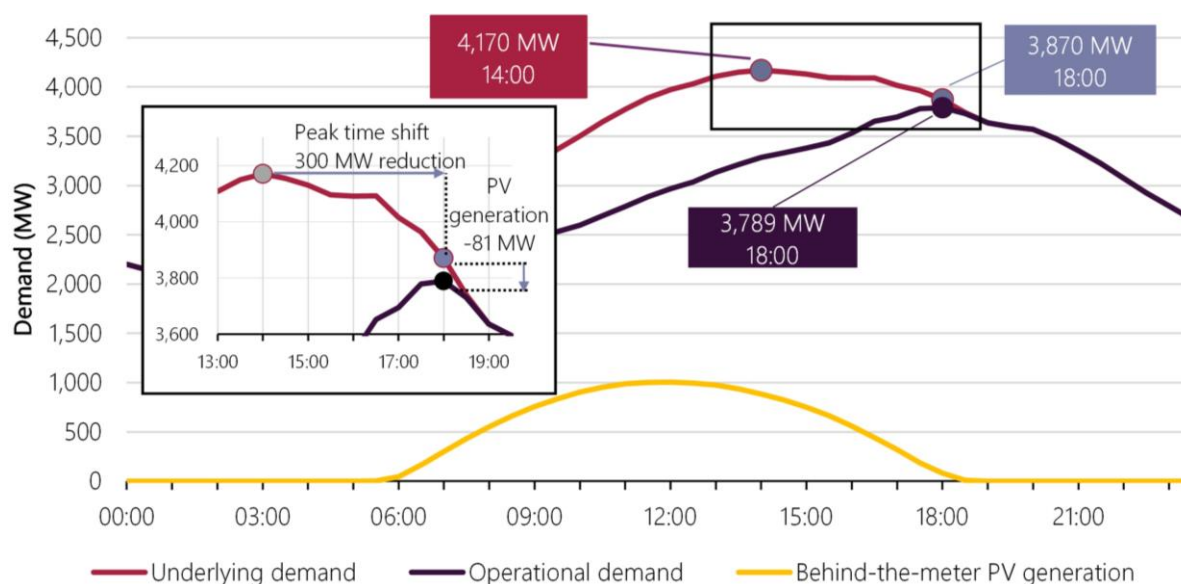
²² Underlying demand refers to operational demand plus an estimate of behind-the-meter PV and battery storage.

²³ These minimums tend to occur on mild (20-25°C) sunny weekends or public holidays in spring and autumn when system loads are lower.

²⁴ AEMO has developed and deployed a real-time frequency stability control room tool to monitor system security in real time.

²⁵ See <https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy>.

Figure 3 Underlying and observed demand profiles on underlying and observed peak demand day, 8 January 2021



Source: AEMO, BOM, CER and Solcast.

RCM changes and other developments

As part of the ETS, the Minister for Energy amended the WEM Rules in December 2020, to defer key events for the 2021 and 2022 Reserve Capacity Cycles. These deferrals were made to provide sufficient time for AEMO and Market Participants to implement changes to the RCM, as published in the Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020 (Amending Rules)²⁶.

The following key changes will take effect for the 2021 Reserve Capacity Cycle:

- Introduction of a certification methodology for Electric Storage Resources.
- The Expression of Interest becoming mandatory for all new capacity (new Facilities and upgrades).
- Changes to the Registration framework.

The Rule Change Panel is currently progressing RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators. This Rule Change Proposal is expected to provide a better assessment of the capacity contribution of the fleet of Intermittent Generators and individual Intermittent Generators to system reliability, and a transparent method that can be used by Market Participants to support their investment planning. Further information about this Rule Change Proposal can be found on the Rule Change Panel's website²⁷.

The 2022 Reserve Capacity Cycle will include the introduction of Network Access Quantities and associated provisions (such as Network Augmentation Funding Facilities). Further details of the changes that apply to the 2021 and 2022 Reserve Capacity Cycles can be found in the Amending Rules.

²⁶ At <https://www.erawa.com.au/cproot/21670/2/Wholesale-Electricity-Market-Amendment-Tranches-2-and-3-Amendments-Rules-2020.pdf>.

²⁷ See https://www.erawa.com.au/rule-change-panel/wem-rule-changes/rule-change-rc_2019_03.

Contents

Executive summary	3
1. Year in review – Reserve Capacity Mechanism	14
2. Changes in supply	16
2.1 Key updates for the 2022-23 Capacity Year	16
2.2 Capacity Credits by Facility Class	16
2.3 Capacity Credits for Facilities with renewable energy sources	22
3. Peak demand, minimum demand, and consumption changes	24
3.1 Historical peak demand	24
3.2 Minimum demand	29
3.3 Historical energy consumption	33
4. Distributed energy resources trends and forecasts	36
4.1 Historical DER uptake trends	36
4.2 DER forecasts	41
5. Peak demand, minimum demand, and consumption forecasts	47
5.1 Peak demand forecasts	48
5.2 Minimum demand forecasts	51
5.3 Consumption forecasts	52
6. Reliability assessment outcomes	56
6.1 Planning Criterion	56
6.2 The Reserve Capacity Target	57
6.3 Availability Classes	58
6.4 Availability Curves	59
6.5 Opportunity for investment	60
7. Market developments and challenges	64
7.1 WEM reviews and rule changes	64
7.2 Energy Transformation Strategy	65
7.3 Infrastructure developments in the SWIS	68
7.4 Maintaining power system security and reliability	70
7.5 Industry trends	72
A1. Supporting forecasts	75
A1.1 Economic growth outlook	75
A1.2 Residential electricity connection forecasts	76
A1.3 New large industrial loads	77

A2.	Forecast methodology and assumptions	78
A2.1	Overview	78
A3.	Reliability assessment methodology	86
A3.1	Expected unserved energy assessment	86
A3.2	Minimum capacity requirements (Availability Classes)	87
A3.3	Availability Curves	88
A3.4	Methodology changes and improvements	89
B1.	Supply-demand balance	90
B2.	Expected unserved energy assessment results	92
B3.	Summer peak demand forecasts	93
B4.	Winter peak demand forecasts	95
B5.	Minimum demand forecasts	97
B6.	Operational consumption forecasts	98
B7.	Power station information in the SWIS	99
B8.	Facility capacities	102
	Measures and abbreviations	105
	Glossary	108

Tables

Table 1	Reserve Capacity Targets (MW)	4
Table 2	Peak demand forecasts for different weather scenarios, expected demand growth (MW)	6
Table 3	Operational consumption forecasts for different demand growth scenarios (gigawatt hours [GWh])	6
Table 4	Distribution of Facilities and Capacity Credit assignments and Capacity Credits to maximum capacity ratio for Scheduled Generators by fuel type	18
Table 5	Operating characteristics for Scheduled Generators	20
Table 6	Distribution of Facilities and Capacity Credit assignments and Capacity Credits to maximum capacity ratio for INSGs by fuel type, 2022-23 Capacity Year	22
Table 7	Comparison of annual peak demand days, 2012-13 to 2020-21	25
Table 8	Comparison of annual underlying peak demand days, 2012-13 to 2020-21	27
Table 9	Minimum demand records since 2020 WEM ESOO	32
Table 10	Consultant DER forecast to scenario mapping	41
Table 11	Difference between 10% POE expected scenario forecasts, 2020 WEM ESOO and 2021 WEM ESOO (MW)	51

Table 12	Reserve Capacity Targets (MW)	57
Table 13	Availability Classes (MW)	59
Table 14	Capacity outlook in the SWIS, 2021-22 to 2023-24 Capacity Years (MW)	62
Table 15	WA GSP (%) annual growth forecasts for different economic growth scenarios, 2021-22 to 2030-31 financial years	76
Table 16	Forecast residential connections growth (%) scenarios, 2021-22 to 2030-31 financial years	77
Table 17	Definitions for key demand and consumption terms in the forecast methodology	79
Table 18	Key assumptions for expected, low and high demand forecasts	80
Table 19	Supply-demand balance, low demand growth scenario (MW)	90
Table 20	Supply-demand balance, expected demand growth scenario (MW)	91
Table 21	Supply-demand balance, high demand growth scenario (MW)	91
Table 22	EUE assessment results	92
Table 23	Summer peak demand forecasts under the low demand growth scenario (MW)	93
Table 24	Summer peak demand forecasts under the expected demand growth scenario (MW)	93
Table 25	Summer peak demand forecasts under the high demand growth scenario (MW)	94
Table 26	Winter peak demand forecasts under the low demand growth scenario (MW)	95
Table 27	Winter peak demand forecasts under the expected demand growth scenario (MW)	95
Table 28	Winter peak demand forecasts under the high demand growth scenario (MW)	96
Table 29	Minimum demand forecasts under the expected demand growth scenario (MW)	97
Table 30	Operational consumption forecasts (GWh)	98
Table 31	Scheduled Generators in the SWIS, 2019-20 Capacity Year	99
Table 32	INSGs in the SWIS, 2019-20 Capacity Year	100
Table 33	Registered generation Facilities – existing and committed (MW)	102
Table 34	Registered DSM Facilities – capability and availability	104

Figures

Figure 1	Reserve Capacity supply-demand balance, 2021-22 to 2030-31	5
Figure 2	Actual and forecast total installed behind-the-meter PV, 2010-11 to 2030-31	7
Figure 3	Underlying and observed demand profiles on underlying and observed peak demand day, 8 January 2021	8
Figure 4	Maximum capacity of Facilities with Capacity Credits assignments by age and fuel type	18
Figure 5	Scheduled Generators map for the SWIS, 2022-23 Capacity Year	19
Figure 6	INSG map for the SWIS, 2022-23 Capacity Year	21
Figure 7	Capacity Credit assignments and number of Facilities with renewable energy sources, 2013-14 to 2022-23 Capacity Years	23

Figure 8	Demand and temperature profiles for the peak demand day and preceding two days (6, 7 and 8 January 2021)	26
Figure 9	Operational and underlying demand profiles on underlying and observed peak demand day, 8 January 2021	27
Figure 10	Summer and winter peak demand, 2012-13 to 2020-21	28
Figure 11	Comparison of summer and winter demand profiles for 2019-20	28
Figure 12	Monthly average of the shift in peak demand timing from 2013-14 to 2019-20	29
Figure 13	Daily minimum load, 2015-16 to 2020-21	30
Figure 14	Comparison of demand on the 10 low demand days for 2015-16 and 2020-21	31
Figure 15	Monthly averages for underlying demand and behind-the-meter PV capacity factors, during the hours of 10:00 to 14:00	31
Figure 16	Minimum demand since WEM start, January 2018 to March 2021	32
Figure 17	Annual operational consumption by sector, 2012-13 to 2019-20	33
Figure 18	Total consumption breakdown, 2012-13 to 2019-20	34
Figure 19	Residential consumption breakdown, 2012-13 to 2019-20	35
Figure 20	Consumption per residential customer, 2012-13 to 2019-20	35
Figure 21	Year-on-year growth in behind-the-meter PV and battery storage, 2012-20	37
Figure 22	Proportion of installed generation capacity, by behind-the-meter PV system size, 2008 to 2021	38
Figure 23	Proportion of installed battery storage, by system size, 2008 to 2021	38
Figure 24	Monthly installed capacity of behind-the-meter PV and battery storage, 2017 to 2021	39
Figure 25	Trend of potential daily behind-the-meter PV generation relative to installed battery storage, 2018 to 2021	40
Figure 26	Behind-the meter PV and battery storage postcode aggregations	40
Figure 27	Actual and forecast installed behind-the-meter PV capacity, 2019-20 to 2030-31	42
Figure 28	Actual and forecast installed capacity of battery storage (behind-the-meter), 2019-20 to 2030-31	43
Figure 29	Modelled daily residential battery charging profile (flat tariff)	44
Figure 30	Forecast total number of EVs, 2020-21 to 2030-31	45
Figure 31	Daily weekday EV charging profiles, June 2031	46
Figure 32	10% POE forecast peak demand under three demand growth scenarios compared to actuals, 2013-14 to 2030-31	48
Figure 33	10%, 50%, and 90% POE peak demand forecasts under the expected demand growth scenario compared to actuals, 2013-14 to 2030-31	49
Figure 34	Distribution of forecast time of 10% POE peak demand, expected demand growth scenario	50
Figure 35	10%, 50%, and 90% POE forecast minimum demand under the expected demand growth scenario compared to actuals, 2013-14 to 2025-26	52
Figure 36	Operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31	53

Figure 37	Residential operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31	54
Figure 38	Business operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31	55
Figure 39	2022-23 Capacity Year Availability Curve	60
Figure 40	2023-24 Capacity Year Availability Curve	60
Figure 41	Reserve Capacity supply-demand balance, 2021-22 to 2030-31	61
Figure 42	Adjustment process for half-hourly modelled demand	81
Figure 43	Behind-the-meter PV capacity factors (monthly)	82
Figure 44	Adjustment process for final business operational consumption forecasts	84

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 *2020 WEM Electricity Statement of Opportunities (ESOO)*²⁸.

- AEMO expects the COVID-19 pandemic impacts on the WA economy will continue to be limited²⁹, with annual growth in gross state product (GSP) expected to largely recover from 1.0% in the 2020-21 financial year to 3.5% by the 2024-25 financial year. Since 2020, AEMO has reviewed the COVID-19 impacts and incorporated these into its peak demand, minimum demand, and operational consumption forecasts in the body of the report.
- In November 2020, a total of 4,807.237 megawatts (MW) of Capacity Credits were assigned to meet the Reserve Capacity Requirement (RCR) of 4,421 MW for the 2020 Reserve Capacity Cycle in relation to the 2022-23 Capacity Year³⁰, representing an 8.7% excess capacity level.
 - For more information on Facilities assigned Capacity Credits for the 2022-23 Capacity Year, see Chapter 2.
 - For the RCR determination for the 2021 Reserve Capacity Cycle in relation to the 2023-24 Capacity Year, see Chapter 6.
- In November 2020, the Reserve Capacity Price (RCP) of \$85,294 per MW per year and the RCP for Transitional Facilities of \$115,425 per MW per year were determined for the 2020 Reserve Capacity Cycle (2022-23 Capacity Year).
- In December 2020, the Minister for Energy amended the WEM Rules to defer key processes for the 2021 and 2022 Reserve Capacity Cycles³¹. These deferrals were made to allow sufficient time for AEMO and Market Participants to implement changes made to the RCM³². Key changes to the 2021 Reserve Capacity Cycle include:
 - It is now mandatory for new Facilities intending to submit an application for Certified Reserve Capacity (CRC) to submit an Expression of Interest (EOI) by 16 August 2021 for the 2021 Reserve Capacity Cycle.

²⁸ See https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2020/2020-wholesale-electricity-market-electricity-statement-of-opportunities.pdf.

²⁹ AEMO engaged BIS Oxford Economics (BIS Oxford) to provide economic forecasts for WA in addition to regions of the National Electricity Market.

³⁰ For Capacity Credits assigned for the 2022-23 Capacity Year, see https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/assignment/2020/capacity-credits-assigned-for-the-2022-23-capacity-year.pdf.

³¹ See the revised timetable for 2021 and 2022 Reserve Capacity Year, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/timetable/2021-and-2022-reserve-capacity-timetables.pdf.

³² Changes published in the Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020 (Amending Rules), at <https://www.erawa.com.au/cproot/21670/2/Wholesale-Electricity-Market-Amendment-Tranches-2-and-3-Amendments-Rules-2020.pdf>.

- A new certification methodology was introduced for Electric Storage Resources (ESR). The CRC window will open on 1 December 2021.
- The Network Access Quantity (NAQ) Framework will be implemented for the 2022 Reserve Capacity Cycle, for the 2024-25 Capacity Year.
- In January 2021, the Benchmark Reserve Capacity Price (BRCP) was determined as \$151,700 per MW per year for the 2021 Reserve Capacity Cycle³³. This is a 6.9% increase over the price determined for the 2020 Reserve Capacity Cycle³⁴.
 - The main driver for this increase was the Economic Regulation Authority’s (ERA’s) amendments to the Weighted Average Cost of Capital (WACC) calculation detailed within the Market Procedure³⁵. These amendments changed the WACC value used in the BRCP calculation from a real value of 3.34% (used in previous years and in the 2021 draft report), to a nominal value of 5.20%.
 - More details on the 2021 BRCP, including the changes to the WACC used, can be found in AEMO’s *Benchmark Reserve Capacity Price for the 2023-24 Capacity Year Final Report*³⁶ and the ERA’s Decision on the BRCP to apply in the 2023-24 Capacity Year³⁷.
- On 8 January 2021, peak demand for the 2020-21 summer was recorded as 3,789 MW³⁸ during the 18:00 to 18:30 period when the estimated impact of behind-the-meter photovoltaics (PV) was 81 MW. This was roughly half the impact (158 MW) observed on the 2019-20 peak demand day (4 February 2020) during the 17:30 to 18:00 period. This reflects the trend of the operational peak shifting to later in the day.
 - Chapter 2 provides details on supply changes.
 - Chapter 3 provides detail on the historical peak demand.
 - Chapter 4 provides analysis on the long-term trends on the uptake of distributed energy resources (DER) for the South West interconnected system (SWIS), and on the DER forecasts for the SWIS.
 - Chapter 5 provides detail on the peak and minimum demand forecasts,
 - Chapter 6 provides detail on the forecast capacity supply and demand balance for the 2023-24 to 2030-31 Capacity Years.
- On 14 March 2021, minimum demand of 954 MW³⁹ was observed, setting a new minimum demand record for the SWIS since market start. The continued rapid uptake of behind-the-meter photovoltaics (PV) is causing significant demand reductions, most pronounced when mild temperature and sunny conditions coincide with lower load over weekend or holiday periods. Current challenges associated with minimum demand are being addressed as part of the DER workstreams within the WA Government’s Energy Transformation Strategy (ETS). AEMO is actively exploring issues and solutions in relation to operational management of minimum demand in conjunction with Energy Policy WA and Western Power.

Information relating to these events and updates are covered in greater detail within this report.

³³ See <https://www.erawa.com.au/cproot/21725/2/-BRCP.2021---BRCP-Decision-Paper-2021.pdf>.

³⁴ See https://www.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.

³⁵ The ERA is responsible for the *Market Procedure: Benchmark Reserve Capacity Price*. Version 7 of this Market Procedure contains the revised WACC parameters that are effective from 9 November 2020. See <https://www.erawa.com.au/electricity/wholesale-electricity-market/marketprocedures>.

³⁶ See <https://www.erawa.com.au/cproot/21724/2/BRCP-Decision-2021---Final-Report-2021-Benchmark-Reserve-Capacity-Price-for-the-2023-24-Capacity-Year.PDF>.

³⁷ See <https://www.erawa.com.au/cproot/21725/2/-BRCP.2021---BRCP-Decision-Paper-2021.PDF>.

³⁸ Measured as the Total Sent Out Generation (TSOG) over a 30-minute Trading Interval. The maximum temperature for the peak demand day was 41.5°C; it was the second-hottest day observed during the 2020-21 summer.

³⁹ The 50% probability of exceedance (POE) minimum demand forecast for 2020-21 under the expected demand growth scenario in the 2020 WEM ESOO was 997 MW.

2. Changes in supply

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

This chapter refers to the Facility classes specified in clause 2.29.1A of the WEM Rules. For the 2021 and 2022 Reserve Capacity Cycles, existing Facilities will be assigned an RCM Facility Class in accordance with section 1.45 of the WEM Rules.

2.1 Key updates for the 2022-23 Capacity Year

Capacity Credits are a tradeable commodity that represents the MW capacity that a Facility (generators or Demand Side Programmes [DSPs]) can deliver to the SWIS. A Facility that has been assigned Capacity Credits can trade them at the administered RCP via AEMO or through bilateral contracts.

For the 2022-23 Capacity Year, 35 Market Participants (up from 33 in the 2021-22 Capacity Year) operating 66 Facilities (equal to the 2021-22 Capacity Year) were assigned a total of 4,807.2 MW of Capacity Credits⁴⁰. The entry of new capacity does not fully offset the retirement of Muja C unit 5, resulting in a 2.4% decline in Capacity Credits assigned compared to the 2021-22 Capacity Year (4,924.8 MW).

Key changes in the 2022-23 Capacity Year compared to the 2021-22 Capacity Year include:

- **New entry** – the East Rockingham waste-to-energy Facility will generate up to 29.0 MW of baseload electricity⁴¹ and was assigned 25.1 MW of Capacity Credits for the 2022-23 Capacity Year. This is the second waste-to-energy Facility to be assigned Capacity Credits after the Phoenix Kwinana waste-to-energy Facility, which was first assigned Capacity Credits for the 2021-22 Capacity Year.
- **Upgrade** – the AmbriSolar farm was assigned 0.2 MW of Capacity Credits and an additional 0.7 MW for a battery storage upgrade to the existing solar farm⁴². This is the first battery storage that has been assigned Capacity Credits.
- **Existing Facilities** – the Tiwest Cogeneration Facility (36.0 MW) was assigned Capacity Credits for the 2022-23 Capacity Year after not being assigned any Capacity Credits for the 2021-22 Capacity Year. The Kalamunda power station (1.3 MW) was not assigned any Capacity Credits for the 2022-23 Capacity Year.
- **Retirement** – Muja C unit 5 (195.0 MW) is scheduled to retire on 1 October 2022.

2.2 Capacity Credits by Facility Class

The Capacity Credits assigned to a Facility reflect 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 outages⁴³, commercial arrangements, and bidding strategies. Newer generators are generally more fuel-efficient and

⁴⁰ Behind-the-meter PV does not receive Capacity Credits.

⁴¹ East Rockingham Waste-to-Energy News statements, at <https://erwte.com.au/news/clean-energy-finance-corporation-cefc-invests-in-east-rockingham>.

⁴² See <http://www.metropower.com.au/about/>.

⁴³ Outage data can be sourced from AEMO's Market Data website, at <http://data.wa.aemo.com.au/#outages>.

can operate for longer periods without scheduled outages. 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 capacity⁴⁴ of Facilities assigned Capacity Credits for the 2022-23 Capacity Year is 5,825.1 MW, comprising:

- **Scheduled Generators** – these make up 4,654.5 MW (79.9%) of the maximum capacity. This category consists of 1,760.2 MW (37.8%) gas, 1,371.1 MW (29.5%) coal, 1,326.0 MW (28.5%) dual (gas/distillate), 132.2 MW (2.8%) distillate, and 65.0 MW (1.4%) waste capabilities.
- **Intermittent Non-Scheduled Generators (INSG)** – these make up 1,170.6 MW (20.1%) of the maximum capacity. This category consists of 788.3 MW (67.3%) wind, 210.0 MW (17.9%) wind and solar, 149.8 MW (12.8%) solar, 21.6 MW (1.8%) landfill gas, and 1.0 MW (0.1%) solar and battery.

For comparison, behind-the-meter PV generation (which does not receive Capacity Credits) had an installed capacity of 1.74 gigawatts (GW) as of April 2021. This is equivalent to around 30% of the maximum capacity of the Scheduled Generators and INSGs that were assigned Capacity Credits for the 2022-23 Capacity Year.

The following sections detail the performance of each Facility class that has been assigned Capacity Credits for the 2022-23 Capacity Year.

2.2.1 Age of Facilities assigned Capacity Credits

Figure 4 shows the maximum capacity of Facilities assigned Capacity Credits for the 2022-23 Capacity Year in MW (represented by the size of the bubbles) by fuel type and age⁴⁵.

The key trends identified are:

- Based on the maximum capacity (5,825.1 MW) of the fleet, 31.7% of this comprises Facilities that are 11-15 years old, followed by those more than 30 years old (15.8%), 21-25 years old (14.9%), and 16-20 years old (14.2%).
- Based on the Facility class, 54.0% (632.4 MW) of the INSG fleet maximum capacity (1,170.6 MW) are Facilities that are 1-5 years old⁴⁶, and 37.9% (1,762.0 MW) of the Scheduled Generators fleet maximum capacity (4,654.5 MW) are Facilities that are 11-15 years old.
- There are no Scheduled Generators that are less than five years old⁴⁷ or 26-30 years old.
- There are no INSGs that are under construction or over 20 years old, except for the Red Hill landfill gas Facility which is 28 years old.
- The median age of all Facilities in the RCM is 15 years, with INSGs generally newer (median age of 10 years) compared to Scheduled Generators (median age of 16 years).
- Coal-fired generators are the oldest with an average age of 26 years and have the greatest age range from 12 to 40 years.

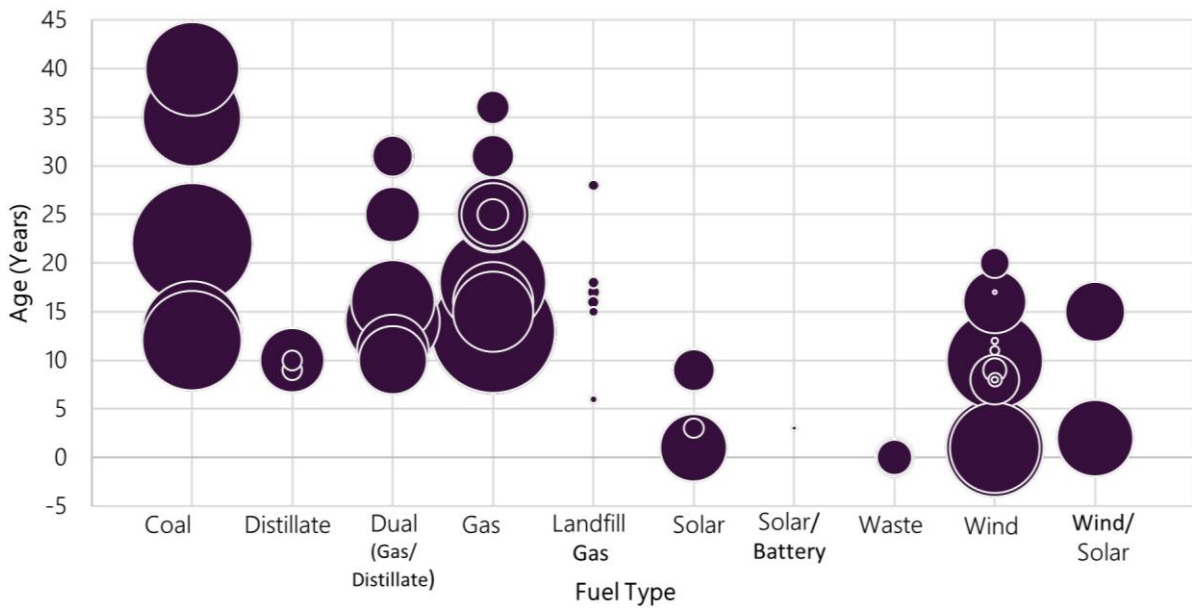
⁴⁴ Maximum capacity data is based on the net sent out generation or installed capacity and can be found on AEMO's Market Data website, at <http://data.wa.aemo.com.au/#facilities>.

⁴⁵ Age has been calculated as at June 2021 and not the age of the Facilities by the 2022-23 Capacity Year.

⁴⁶ This differs from the 2020 WEM ESOO because Yandin and Warradarge wind farms, and Merredin solar farm, all commenced operations from June 2020.

⁴⁷ This excludes the East Rockingham and Phoenix Kwinana waste-to-energy Facilities that are both currently under construction.

Figure 4 Maximum capacity of Facilities with Capacity Credits assignments by age and fuel type^A



A. Facilities that are under construction or less than one year old are represented by zero or negative values for age.

2.2.2 Scheduled Generators

Scheduled Generators were assigned a total of 4,523.1 MW of Capacity Credits for the 2022-23 Capacity Year with a combined total of 4,654.5 MW in maximum capacity. This represents a ratio of 97.2% for Capacity Credits to maximum capacity, as shown in Table 4. Scheduled Generators are assigned Capacity Credits based on their capability at 41°C, which typically equals or is close to their maximum capacity.

Table 4 Distribution of Facilities and Capacity Credit assignments and Capacity Credits to maximum capacity ratio for Scheduled Generators by fuel type

Fuel type	Facilities		Capacity Credits		Maximum capacity		Capacity Credits to maximum capacity ratio
	Number	% of total	MW	Share (%)	MW	Share (%)	%
Coal	6	15.4	1,366.2	30.2	1,371.1	29.5	99.6
Distillate	5	12.8	121.6	2.7	132.2	2.8	92.0
Dual (gas/ distillate)	14	35.9	1,277.9	28.3	1,326.0	28.5	96.4
Gas	12	30.8	1,699.2	37.6	1,760.2	37.8	96.5
Waste	2	5.1	58.1	1.3	65.0	1.4	89.4
Total	39	100.0	4,523.1	100.0	4,654.5	100.0	97.2

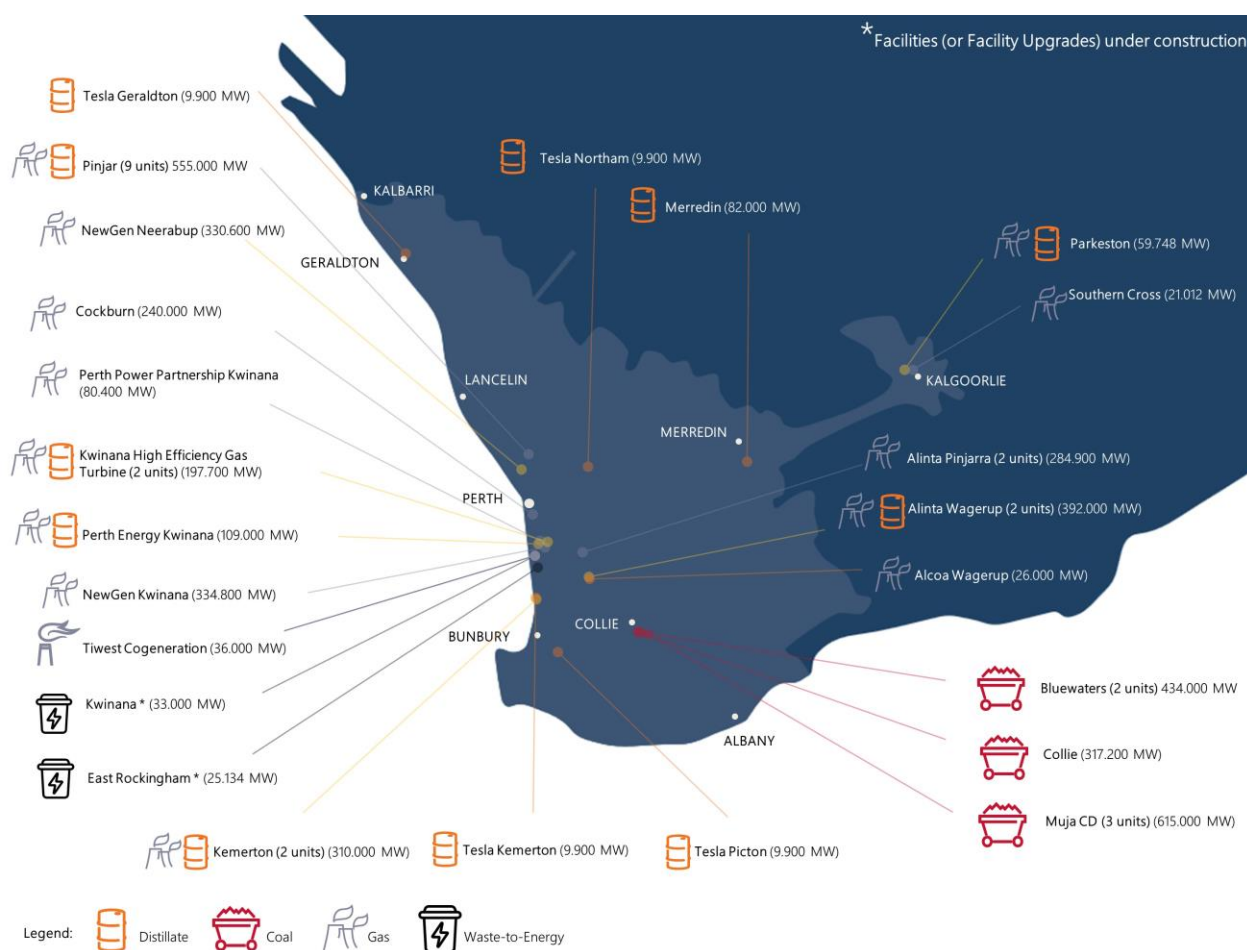
The Scheduled Generator fleet has not changed significantly between the 2021-22 and 2022-23 Capacity Years, with the changes being the entry of East Rockingham waste-to-energy (25.1 MW) and the Muja C unit 5 retirement (195.0 MW). Among existing Facilities, Tiwest Cogeneration Facility (36.0 MW) was assigned Capacity Credits while Kalamunda power station (1.3 MW) was not assigned any Capacity Credits for the 2022-23 Capacity Year.

In summary, key observations in the Scheduled Generator fleet assigned Capacity Credits for the 2022-23 Capacity Year include:

- Scheduled Generators represent almost 94.1% of the Capacity Credits issued.
- Gas (37.6%) Facilities hold the largest share of Capacity Credits, followed by coal (30.2%) and dual-fuel Facilities (28.3%).
- Alternative fuel sources are emerging, with two waste-to-energy Facilities holding Capacity Credits for the 2022-23 Capacity Year.

The locations and Capacity Credit assignments for Scheduled Generators in the 2022-23 Capacity Year are shown in Figure 5.

Figure 5 Scheduled Generators map for the SWIS, 2022-23 Capacity Year



AEMO classifies Scheduled Generators as:

- **Baseload capacity** – operates more than 70% of the time.
- **Mid-merit capacity** – operates between 10% and 70% of the time.
- **Peaking capacity** – operates less than 10% of the time.

The classification of baseload, mid-merit, and peaking Facilities is based on the percentage of Trading Intervals in the 2019-20 Capacity Year the Facility operated, adjusted for full outages. A full outage has been defined as a Trading Interval when a Facility has taken an outage equal to its Capacity Credits assigned for the 2019-20 Capacity Year.

Table 5 shows the operating characteristics of existing Scheduled Generators⁴⁸. In summary:

- All coal Facilities are baseload capacity, all distillate Facilities are peaking capacity, gas Facilities are a combination of baseload and mid-merit capacities, and dual-fuel Facilities are in each category.
- Compared to the 2020 WEM ESOO, the percentage of Capacity Credits assigned to baseload Facilities increased from 49.4% to 51.9%, mid-merit increased from 30.9% to 32.7%, peaking Facilities declined from 19.0% to 14.2%, and unclassified Facilities increased from 0.7% to 1.3%⁴⁹.
- Baseload capacity (totalling 2,347.0 MW of Capacity Credits) consists of 58.2% coal, 33.4% gas, and 8.4% dual-fuel Facilities.
- Mid-merit capacity (totalling 1,476.8 MW of Capacity Credits) consists of 62.0% gas and 38.0% dual-fuel Facilities.
- Peaking capacity (totalling 641.1 MW of Capacity Credits) consists of 81.0% dual-fuel Facilities and 19.0% distillate Facilities.

Table 5 Operating characteristics for Scheduled Generators

Fuel type	Baseload		Mid-merit		Peaking		Unclassified		Total
	MW	%	MW	%	MW	%	MW	%	MW
Coal	1,366.2	58.2	NA	NA	NA	NA	NA	NA	1,366.2
Distillate	NA	NA	NA	NA	121.6	19.0	NA	NA	121.6
Dual (gas/distillate)	197.7	8.4	560.7	38.0	519.5	81.0	NA	NA	1,277.9
Gas	783.1	33.4	916.1	62.0	NA	NA	NA	NA	1,699.2
Waste	NA	NA	NA	NA	NA	NA	58.1	100.0	58.1
Total	2,347.0	51.9	1,476.8	32.7	641.1	14.2	58.1	1.3	4,523.1

2.2.3 Intermittent Non-Scheduled Generators

INSG capacity relates to Facilities that cannot be scheduled because the level of output is dependent on factors beyond the control of the operator. These are landfill gas, wind, solar, and hybrid Facilities that have an intermittent generation component (e.g. wind/solar, solar/battery)⁵⁰. These Facilities are assigned Capacity Credits based on the Relevant Level Methodology (RLM)⁵¹, which assesses the capacity value of INSGs based on their generation during periods with the lowest level of surplus capacity. These periods are more likely to occur when demand in the SWIS is high.

The assigned Capacity Credits for INSGs decreased by 1.4% from 201.1 MW to 198.1 MW between the 2021-22 and 2022-23 Capacity Years. This decrease was a result of annual variation in Relevant Level for solar and landfill gas Facilities, partially offset by wind Facilities (up 2.4%) and battery storage upgrades.

⁴⁸ This does not include Phoenix Kwinana waste-to-energy and East Rockingham waste-to-energy, which is scheduled to commence operations in October 2021 and October 2022 respectively.

⁴⁹ Most of the changes in percentage shares are due to the retirement of Muja C unit 5, which affects the overall quantity of capacity available in the RCM. The shift in the peaking and mid-merit categories is attributed to the Cockburn power station, which was reclassified as mid-merit capacity. The unclassified category includes the Phoenix Kwinana and East Rockingham waste-to-energy Facilities, which are currently under construction.

⁵⁰ From the 2021 Reserve Capacity Cycle, ESRs (including hybrid Facilities that contain an ESR) will be assigned Capacity Credits based on a linear derating methodology and not the Relevant Level, with some exceptions.

⁵¹ The Rule Change Panel is currently progressing RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generator. This Rule Change Proposal will change the Relevant Level Methodology used to assign Certified Reserve Capacity to Intermittent Generators. The Rule Change Proposal is expected to provide a better assessment of the capacity contribution of the fleet of Intermittent Generators and individual Intermittent Generators to system reliability. See: https://www.erawa.com.au/rule-change-panel/wem-rule-changes/rule-change-rc_2019_03.

The three largest Facilities (by Capacity Credits) accounted for almost half of the INSG fleet – Yandin wind farm (17.2% share), Warradarge wind farm (15.3% share), and Badgingarra wind/solar farm (13.2% share).

The total maximum capacity of INSGs assigned Capacity Credits for the 2022-23 Capacity Year is 1,170.6 MW, representing 20.1% of the total maximum capacity across all Facility classes. The average Capacity Credit to maximum capacity ratio for INSGs is 16.9% compared with Scheduled Generators at 97.2%, reflecting the different methodologies used to calculate their capacity contributions.

The Capacity Credit assignment, maximum capacity, and location of each INSG Facility for the 2022-23 Capacity Year is shown in Figure 6.

Figure 6 INSG map for the SWIS, 2022-23 Capacity Year

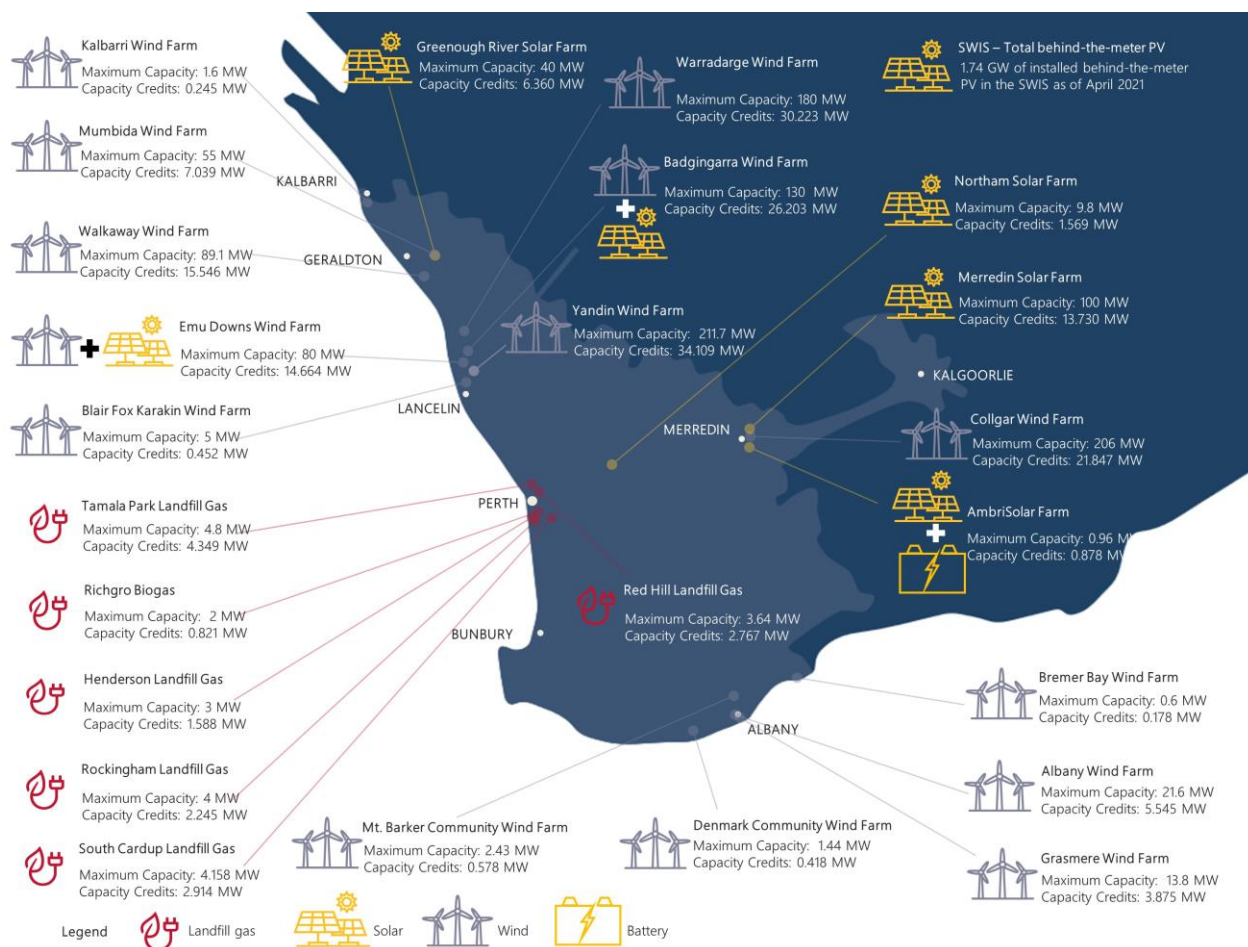


Table 6 shows the distribution of Facilities and Capacity Credit assignments and ratio of Capacity Credits to maximum capacity by technology type (landfill gas, solar, wind, or wind/solar hybrid) for the 2022-23 Capacity Year. In summary:

- Capacity Credits to maximum capacity ratios vary significantly across fuel types.
- The highest Capacity Credits to maximum capacity ratio was achieved by the AmbriSolar farm (91.5%), largely because of the addition of battery storage, followed by Tamala Park (90.6%) and Red Hill (76.0%), which are both landfill gas Facilities.
- The lowest ratios were calculated for Karakin wind farm (9.0%), Collgar wind farm (10.6%), and Mumbida wind farm (12.8%).

Table 6 Distribution of Facilities and Capacity Credit assignments and Capacity Credits to maximum capacity ratio for INSGs by fuel type, 2022-23 Capacity Year

Fuel type			Capacity Credits		Maximum capacity		Capacity Credits to maximum capacity ratio
	Number	% of total	MW	Share (%)	MW	Share (%)	%
Landfill gas	6	25.0	14.7	7.4	21.6	1.8	68.0
Solar	3	12.5	21.7	10.9	149.8	12.8	14.5
Solar/battery	1	4.2	0.9	0.4	1.0	0.1	91.5
Wind	12	50.0	120.1	60.6	788.3	67.3	15.2
Wind/solar	2	8.0	40.9	20.6	210.0	17.9	19.5
Total	24	100.0	198.1	100.0	1,170.6	100.0	16.9

2.2.4 Demand Side Programmes

Three DSPs were assigned a total of 86.0 MW of Capacity Credits in the 2022-23 Capacity Year, representing 1.8% of the total Capacity Credits assigned for the 2022-23 Capacity Year. Capacity Credits assigned to DSPs increased by 1.5 MW between the 2021-22 and 2022-23 Capacity Years, reflecting an increase for the Wesfarmers Kleenheat Gas DSP Facility. The Capacity Credits assigned to the remaining two DSPs were unchanged from the 2021-22 Capacity Year.

2.3 Capacity Credits for Facilities with renewable energy sources

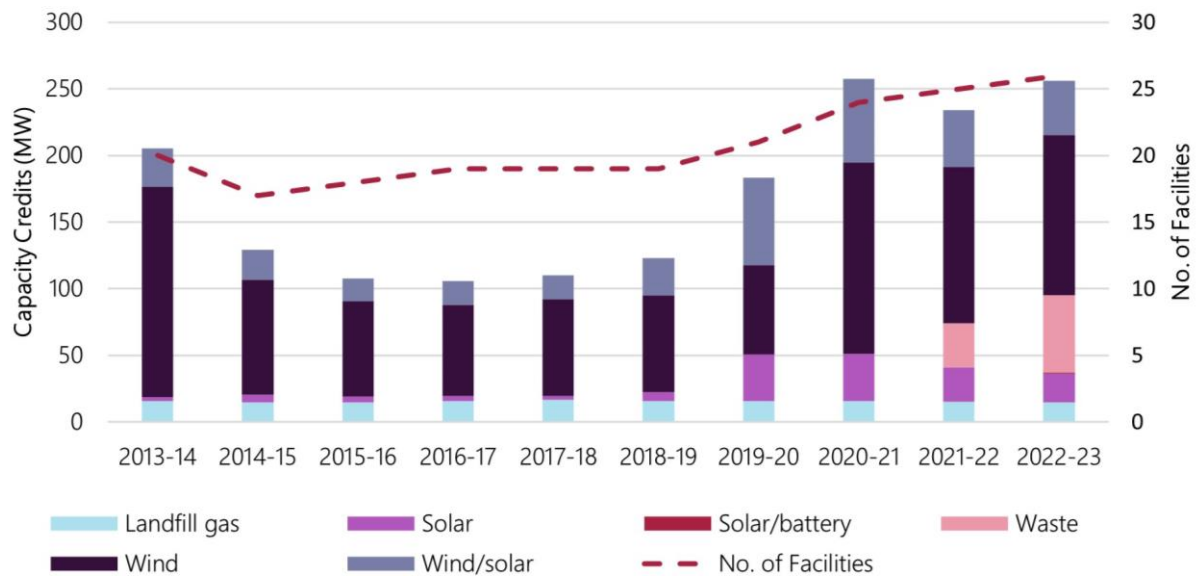
Facilities with renewable energy sources⁵² include INSGs (wind, wind/solar, solar, solar/battery, and landfill gas fuel types) and Scheduled Generators (waste-to-energy fuel type). A total of 26 Facilities with renewable energy sources were assigned Capacity Credits for the 2022-23 Capacity Year. Capacity Credits increased by 9.5% from 234.1 MW in the 2021-22 Capacity Year to 256.3 MW in the 2022-23 Capacity Year.

Figure 7 shows the fuel mix of Facilities with renewable energy sources that were assigned Capacity Credits over a 10-year period. The following trends can be observed:

- An increase in the variation in fuel mix, with the addition of waste-to-energy from the 2021-22 Capacity Year onwards and a battery storage upgrade to an existing Facility in the 2022-23 Capacity Year.
- A steady increase in the number of Facilities with renewable energy sources participating in the RCM in the 2013-14 to 2018-19 Capacity Years (17 to 20 Facilities), which has increased to 26 Facilities in the 2022-23 Capacity Year.

⁵² Renewable energy is produced using natural resources that are constantly replaced and never run out, with a range of renewable energy technologies. See <https://arena.gov.au/what-is-renewable-energy>.

Figure 7 Capacity Credit assignments and number of Facilities with renewable energy sources, 2013-14 to 2022-23 Capacity Years^A



A. Includes INSGs (wind, wind/solar, solar, solar/battery, and landfill gas) and Scheduled Generators (waste).

3. Peak demand, minimum demand, and consumption changes

The 2020-21 summer peak demand of 3,789 MW was 130 MW lower than the previous year (2019-20) but was still one of the highest annual peaks observed since the energy market commenced in 2006.

Six new minimum operational demand records have been set since the 2020 WEM ESOO, driven by the continued increase in behind-the-meter PV generation.

Operational consumption during the 2019-20 Capacity Year increased by 2.1% compared to the previous year, while residential behind-the-meter PV generation grew by 245 gigawatt hours (GWh).

3.1 Historical peak demand

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

- Sections 3.1.1 and 3.1.2 examine the 2020-21 operational and underlying peak demand, respectively, in the context of previously observed trends.
- Section 3.1.3 investigates seasonal trends in peak demand and includes a discussion of the 2019-20 winter peak demand.

The following definitions apply throughout this chapter, unless otherwise specified:

- The reported temperature data is measured at the Perth Airport weather station (station identification number 9021)⁵³.
- **Demand**⁵⁴ refers to operational demand, and **underlying demand** refers to demand plus an estimate of behind-the-meter PV generation⁵⁵ and battery storage.
- **Delivered consumption** means the electricity delivered from the grid to end consumers, and **underlying consumption** means operational consumption plus an estimate of behind-the-meter PV generation.

⁵³ All temperature data is sourced from the Bureau of Meteorology (BOM) from the Perth Airport weather station at a half-hourly resolution and is based on the maximum temperature recorded in that interval. The Perth Airport weather station is a long-term reference station (opened in 1944) and for the purposes of the WEM ESOO is considered broadly representative of weather conditions for the SWIS.

⁵⁴ 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 peak demand is identified as the highest operational demand calculated for a Capacity Year.

⁵⁵ Behind-the-meter PV generation estimates are based on solar capacity factor traces sourced from Solar and Storage Modelling Pty Ltd (Solcast), combined with Installation figures provided by the Clean Energy Regulator (CER) with minor adjustments made by AEMO (as of April 2021), and with AEMO estimates of commercial PV installations ranging between 100 kilowatts (kW) and 10 MW that do not hold Capacity Credits in the WEM. Due to the current relatively low uptake of behind-the-meter battery storage in the SWIS, its impact on historical underlying demand is negligible and is not calculated in this chapter.

- The seasons are split into **summer**⁵⁶ (Trading Months December – March), **winter** (Trading Months June – August), and the **shoulder season**, which includes all other months.

All data in this section is presented in Capacity Years unless otherwise specified.

3.1.1 Peak demand

In this section, the 2020-21 summer peak demand is discussed in the context of historical trends. AEMO will publish a separate piece of analysis on customers' response to the Individual Reserve Capacity Requirement⁵⁷ (IRCR) mechanism and the resulting impact on load reduction on the peak demand day. The supplementary IRCR analysis will be published after the 2021 WEM ESOO.

The 2020-21 summer peak

The 2020-21 summer peak demand of 3,789 MW occurred on 8 January 2021, and was 130 MW lower than last year's peak (3,919 MW). The following observations can be made, comparing this peak demand with historical peak demand (see Table 7):

- Annual peak demand days continue to coincide with a succession of hot days, typically three days with maximum temperatures above 35°C. The maximum temperature on the peak day has exceeded 40°C in six of the last nine Capacity Years.
- Behind-the-meter PV continues to push peak demand to occur later in the day. The daily peak is shifting closer to sunset (Trading Intervals 18:00 to 19:30), when the impact of solar generation is minimal.

Table 7 Comparison of annual peak demand days, 2012-13 to 2020-21^A

Capacity Year	Date	Trading Interval commencing	Peak demand (MW)	Daily maximum temperature (°C)	Moving average temperature ^B (°C)	Peak demand reduction from PV (MW)
2020-21	8 January 2021	18:00	3,789	41.5	38.8	81
2019-20	4 February 2020	17:30	3,919	43.2	39.0	158
2018-19	7 February 2019	17:30	3,256	35.8	36.4	137
2017-18	13 March 2018	17:30	3,616	38.4	35.5	59
2016-17	21 December 2016	17:00	3,543	42.7	35.0	111
2015-16	8 February 2016	17:30	4,004	42.6	38.9	71
2014-15	5 January 2015	15:30	3,744	44.1	37.3	107
2013-14	20 January 2014	17:30	3,702	38.5	38.9	46
2012-13	12 February 2013	16:30	3,739	41.1	39.6	37

A. 2020-21 includes data up to 31 March 2021.

B. Calculated based on a three-day moving average of maximum temperature.

Source: AEMO, BOM, Clean Energy Regulator (CER) and Solcast.

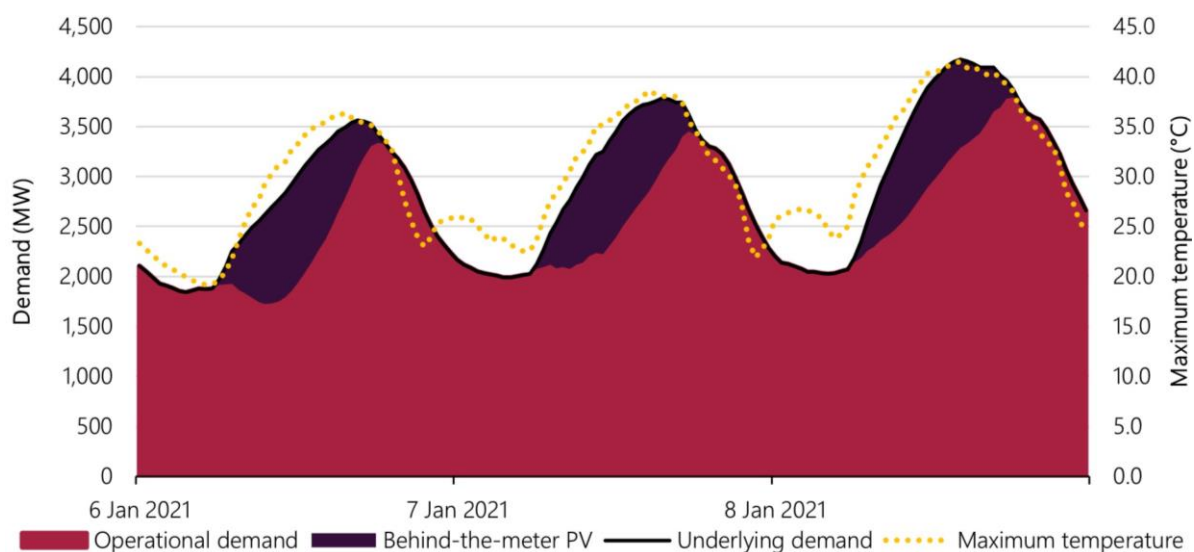
⁵⁶ Summer refers to the Hot Season as defined in the WEM Rules which is the period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April.

⁵⁷ The IRCR financially incentivises Market Customers to reduce consumption during peak demand periods and consequently minimise exposure to capacity payments.

To further illustrate the impacts of prior hot days on peak demand, Figure 8 shows the days preceding the 2020-21 summer peak day, displaying the temperature and demand profiles from 6-8 January 2021:

- The 2020-21 peak demand day was the third day in a row exceeding 36°C. Daily maximum temperatures rose from 36.6°C to 41.5°C across the three days, resulting in higher demand with overnight lows in the range of 19.2°C to 23.8°C.
- Peak demand for 2020-21 on 8 January 2021 was 171 MW higher than the next highest peak, which occurred on 23 December 2020, when the maximum temperature reached 40.3°C.

Figure 8 Demand and temperature profiles for the peak demand day and preceding two days (6, 7 and 8 January 2021)



Source: AEMO, BOM, CER and Solcast.

3.1.2 Underlying peak demand

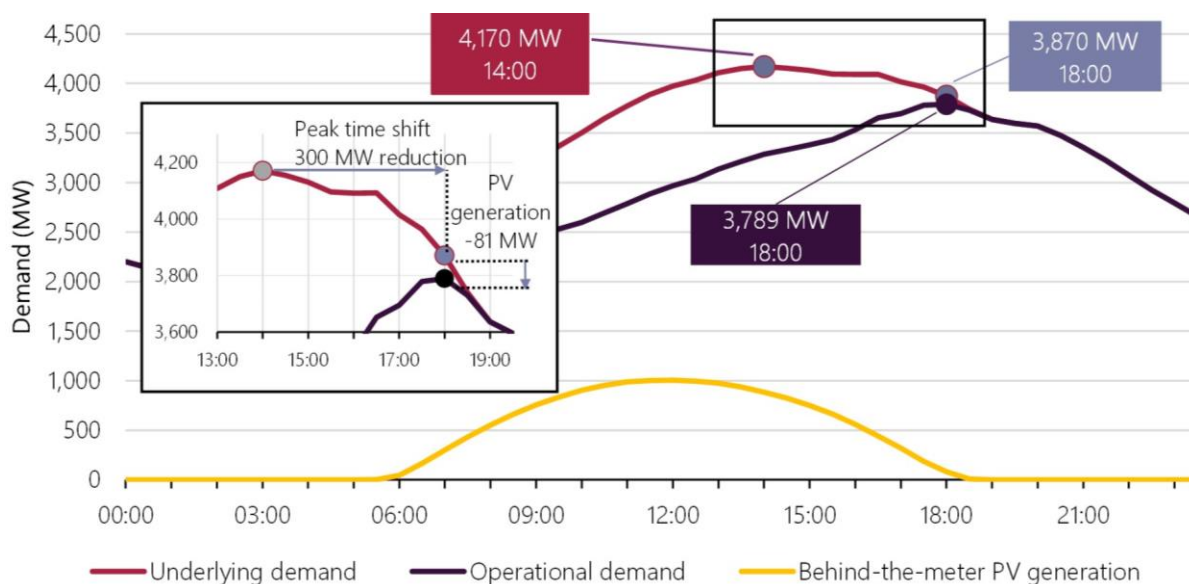
Underlying peak demand is the estimated maximum demand that would have occurred if there was no generation from behind-the-meter PV. In the 2020-21 summer, the underlying peak demand occurred on the same day as the peak demand day (8 January 2021). Figure 9 compares the demand profile between underlying and operational demand on this day.

Figure 9 shows that:

- Underlying peak demand is estimated at 4,170 MW and occurred during the 14:00 to 14:30 Trading Interval, four hours before the occurrence of the operational peak. The timing of underlying peak demand coincided with the warmest part of the day at 41.5°C and is the earliest underlying peak demand since the 2010-11 Capacity Year. This is also the highest estimated underlying peak demand for the SWIS since market start.
- The difference between underlying and peak demand was approximately 381 MW. Of this difference, 300 MW was caused by the peak demand time-shift effect, and 81 MW was caused by the direct reduction in demand as a result of behind-the-meter PV generation. This is the greatest peak reduction observed on an annual underlying peak day to date (see Table 8).

Peak demand continues to shift later in the day each year. This is largely driven by the rapid uptake of behind-the-meter PV, which effectively reduces demand, particularly between Trading Interval 10:00 and Trading Interval 14:00, although behind-the-meter PV output still has a material impact until around Trading Interval 18:00.

Figure 9 Operational and underlying demand profiles on underlying and observed peak demand day, 8 January 2021



Source: AEMO, BOM, CER and Solcast.

Table 8 Comparison of annual underlying peak demand days, 2012-13 to 2020-21^A

Capacity Year	Date	Estimated underlying peak ^B Trading Interval	Estimate of underlying peak demand (MW)	Peak demand Trading Interval	Peak demand (MW)	Peak time shift (hours)	Reduction in peak	
							From PV generation (MW)	From peak time-shift (MW)
2020-21	8 January 2021	14:00	4,170	18:00	3,789	4:00	81	300
2019-20	4 February 2020	17:00	4,095	17:30	3,919	0:30	158	18
2018-19	7 February 2019	16:00	3,513	17:30	3,256	1:30	137	120
2017-18	13 March 2018	16:30	3,735	17:30	3,616	1:00	59	60
2016-17	21 December 2016	15:30	3,724	17:00	3,543	1:30	111	70
2015-16	8 February 2016	16:30	4,142	17:30	4,004	1:00	71	67
2014-15	5 January 2015	15:30	3,851	15:30	3,744	-	107	-
2013-14	21 January 2014 ^C	16:30	3,782	17:00	3,691	0:30	71	20
2012-13	12 February 2013	16:00	3,782	16:30	3,739	0:30	37	6

A. 2020-21 includes data up to 31 March 2021.

B. Solcast's historical estimates of behind-the-meter PV capacity factors have been revised, which will result in small variations from the 2020 WEM ESOO.

C. Underlying peak demand occurred on a different day to peak demand.

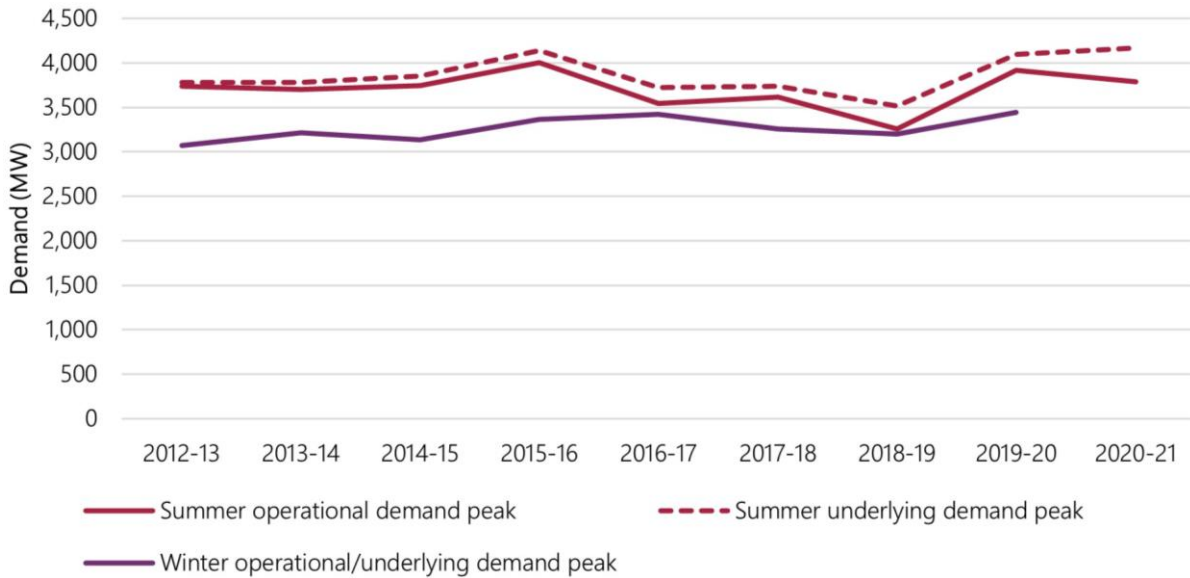
Source: AEMO, CER and Solcast.

3.1.3 Seasonal trends and winter peak demand

Winter operational and underlying peak demand values are identical for the observed period, because winter peak demand historically occurred during night-time hours, when there is no effect from behind-the-meter PV generation. Over the analysis period, the difference between summer and winter peak demand reduces

over time as the peak demand occurs in the evening. However, despite peak demand reduction due to behind-the-meter PV, annual peak demand continues to occur in summer in the SWIS (Figure 10).

Figure 10 Summer and winter peak demand, 2012-13 to 2020-21^{A,B}



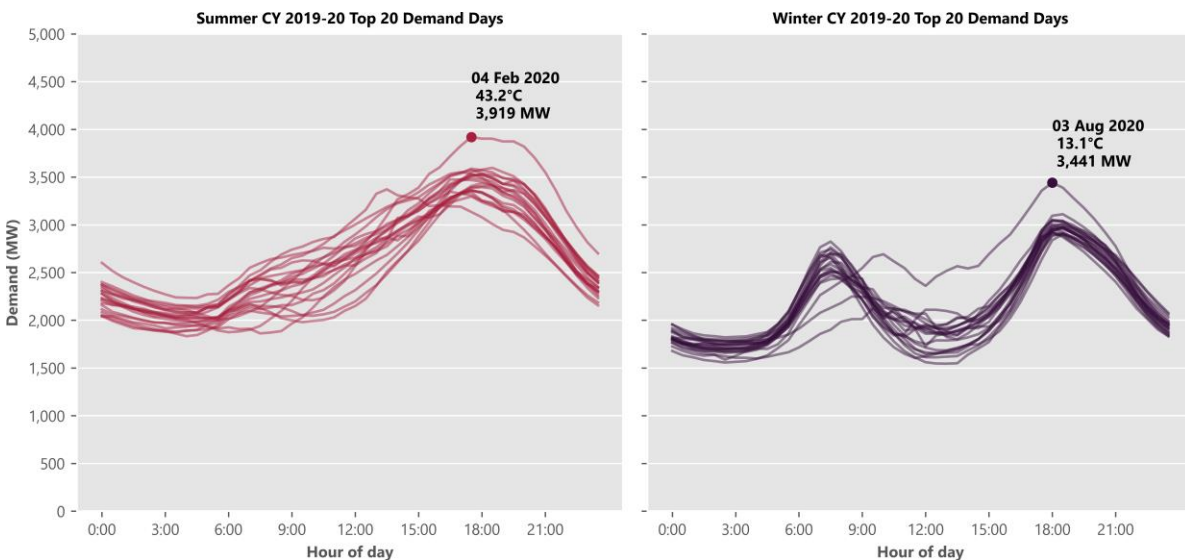
A. At the time of publication, data for winter 2020-21 was not available.

B. No distinction has been made between winter operational demand and underlying demand, as the values are identical for the observed period.

Source: AEMO, CER and Solcast.

The daily load profile in the SWIS is typically bimodal, with the exception of higher demand days in summer, as shown in Figure 11.

Figure 11 Comparison of summer and winter demand profiles for 2019-20^A



A. Based on the top 20 peak demand days for the summer and winter season of 2019-20.

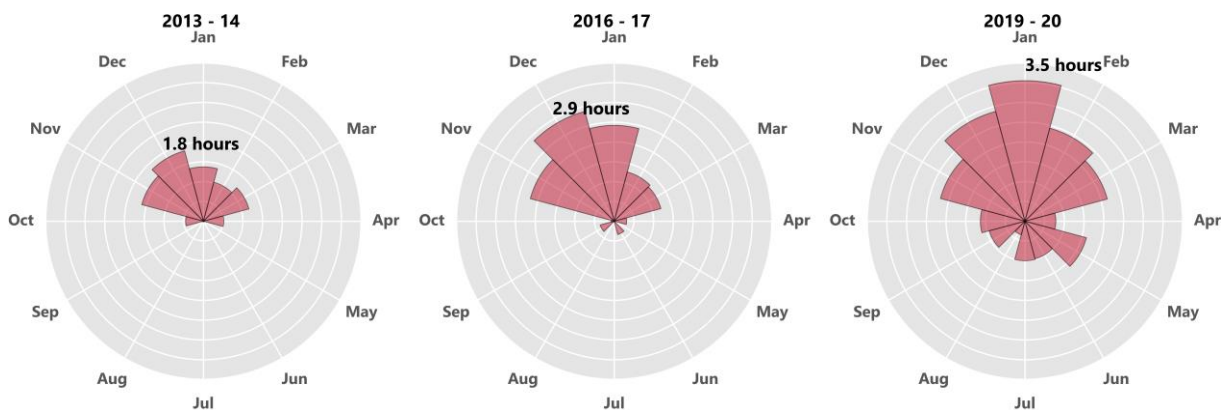
Source: AEMO, BOM, CER and Solcast.

3.1.4 Peak demand timing

As detailed previously for the 2020-21 peak demand day (8 January 2021), the timing of peak demand has shifted, particularly during summer. This shift in the timing of peak demand is a common occurrence and is not limited to extreme weather events.

This timing separation between the underlying and peak demand has grown from a maximum (monthly average) of 1.8 hours in 2013-14 to 3.5 hours⁵⁸ in 2019-20 (Figure 12). The shift is attributable to growth in behind-the-meter PV generation, which has resulted in peak demand frequently occurring closer to sunset. Behind-the-meter PV generation is substantially lower during winter and has minimal influence on peak demand timing, as shown in Figure 12.

Figure 12 Monthly average of the shift^A in peak demand timing from 2013-14 to 2019-20



A. The shift in peak demand is the timing difference between underlying and peak demand. It is presented in Figure 12 as the average for each month of 2013-14, 2016-17, and 2019-20.

Source: AEMO, CER and Solcast.

3.2 Minimum demand

Minimum demand events are frequently occurring during late spring and early autumn when clear skies are coupled with mild temperatures. The mild temperatures and continuous uptake of behind-the-meter PV have resulted in six new minimum demand records⁵⁹ being set in the SWIS since the 2020 WEM ESOO was published.

The latest minimum was 954 MW on 14 March 2021, breaking the previous record of 958 MW set a day earlier. Both records occurred during Trading Intervals when ambient temperatures were relatively mild (23.8°C and 25.4°C respectively).

3.2.1 Historical trends

Historically, daily minimum demand occurred during overnight periods when residential and commercial energy consumption was low. However, the rapid uptake of behind-the-meter PV is now contributing to lower midday demand, despite no equivalent reduction in underlying demand during these periods. In the 2019-20 Capacity Year, daily minimum demand was observed to occur during daytime hours for 64% of the time, up from 11% of the time in the 2016-17 Capacity Year.

Figure 13 illustrates the impact of behind-the-meter PV on reducing minimum demand. It compares historical daily minimums between demand and underlying demand from 2014-15 to 2020-21, showing that:

- The variance between underlying and operational minimum demand increases each year as underlying demand increases⁶⁰ while operational demand declines.
- Demand minimums are most pronounced when mild temperature (~22-23°C) and sunny conditions coincide with low-load periods typical during weekends or holidays.

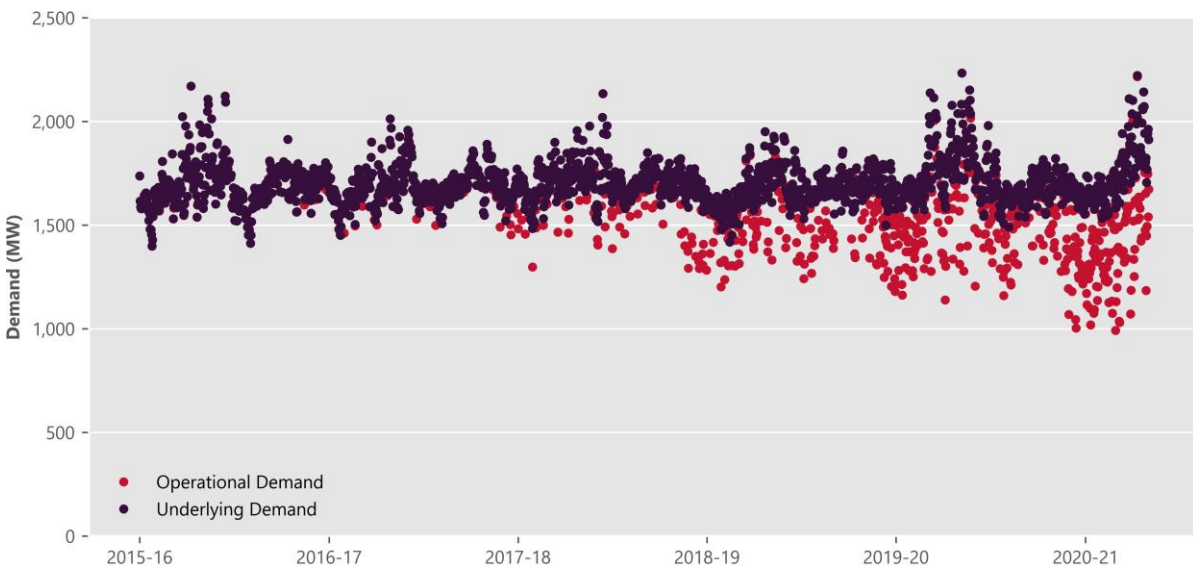
⁵⁸ These values are averaged across a month; 1.8 hours equates to less than four Trading Intervals, and 3.5 hours equals seven Trading Intervals.

⁵⁹ The six new minimum demand records set since the 2020 WEM ESOO was published are 30 August 2020 (1,068 MW), 12 September 2020 (1,044 MW), 13 September 2020 (1,004 MW), 28 November 2020 (991 MW), 13 March 2021 (958 MW) and 14 March 2021 (954 MW).

⁶⁰ Annual underlying minimum demand increased at an annual rate of 2.3% between 2015-16 and 2020-21.

- Annual minimums in demand have decreased at an average annual rate of 7.9% between 2015-16 and 2020-21⁶¹.
 - From October 2020 to February 2021, behind-the-meter PV was estimated to have reduced daily minimum demand by 265 MW (on average). The greatest reduction in daily minimum demand was 670 MW, observed on 5 December 2020.
 - A minimum demand record was set on 14 March 2021 when behind-the-meter PV reduced demand by 1,130 MW (see Table 9).
 - In November 2020, minimum demand dipped below 1,000 MW for the first time.

Figure 13 Daily minimum load, 2015-16 to 2020-21



Source: AEMO, CER and Solcast.

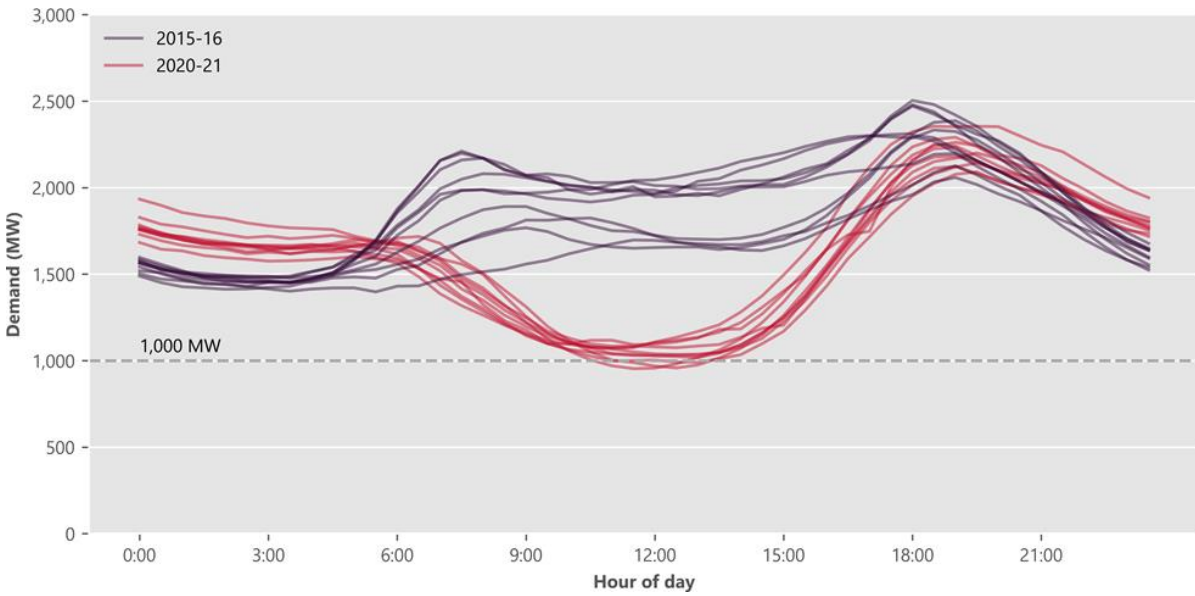
The intraday demand profile for low demand days has changed significantly in recent years.

Figure 14 shows how demand appears to ‘hollow-out’ between 10:00 and 14:00, which corresponds to the daily period of peak behind-the-meter PV generation. This midday demand reduction will continue to grow in step with the sustained adoption of behind-the-meter PV.

The timing of minimum demand is shifting closer to the middle of the day when behind-the-meter PV generation is at its highest. Previously, minimum demand could be expected to occur overnight and in the early hours of the morning, as shown in Figure 14.

⁶¹ Includes data up until 30 March 2021.

Figure 14 Comparison of demand on the 10 low demand days for 2015-16 and 2020-21

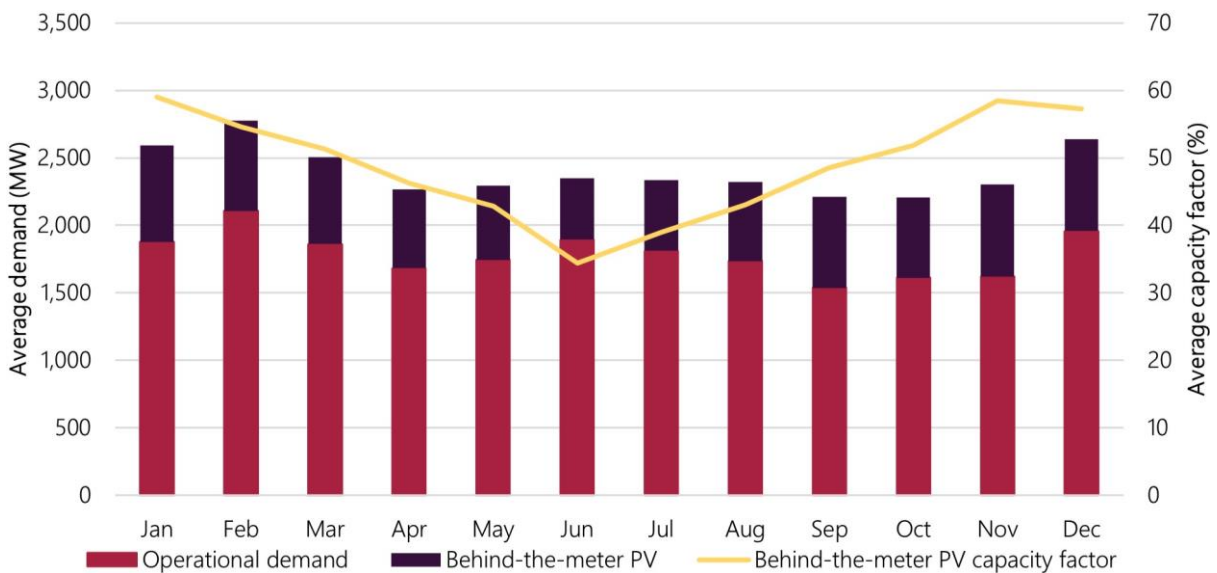


Source: AEMO.

3.2.2 Seasonal trends

The cumulative uptake of behind-the-meter PV has resulted in substantial reductions in average demand throughout the year. Figure 15 illustrates that the average behind-the-meter PV capacity factors⁶² (from Trading Intervals 10:00 to 14:00 inclusive) vary significantly across the year, from as high as 59% in January down to 34% in June. Behind-the-meter PV has a lower impact on average winter demand.

Figure 15 Monthly averages for underlying demand and behind-the-meter PV capacity factors, during the hours of 10:00 to 14:00^A



A. All figure values are calculated using data from 2018-19 and 2019-20.
Source: AEMO, CER and Solcast.

⁶² PV capacity factors are estimated by Solcast and represent the proportion of expected PV generation relative to the installed capacity at a point in time

3.2.3 Minimum demand records

The previous minimum demand record of 1,138 MW (set 4 January 2020) was broken six times after the 2020 WEM ESOO was published (Table 9). These records occurred in the period between late winter and the shoulder season of 2019-20 when sunny days were coupled with milder temperatures. The final two records occurred once milder weather started to return in March 2021. The current minimum demand record stands at 954 MW, which occurred during the 11:30 to 12:00 Trading Interval on 14 March 2021, and was observed on a weekend despite a relatively warm daily maximum temperature of 28.4°C.

Table 9 Minimum demand records since 2020 WEM ESOO

Date	Trading Interval commencing	Day of week	Minimum demand (MW)	Daily maximum temperature (°C)	Demand reduction from PV ^A (MW)
30 August 2020	12:30	Sunday	1,068	20.6	966
12 September 2020	12:00	Saturday	1,044	20.8	991
13 September 2020	12:00	Sunday	1,004	24.5	990
28 November 2020	13:00	Saturday	991	24.2	1,050
13 March 2021^B	12:30	Saturday	958	26.0	1,140
14 March 2021^B	11:30	Sunday	954	28.4	1,130

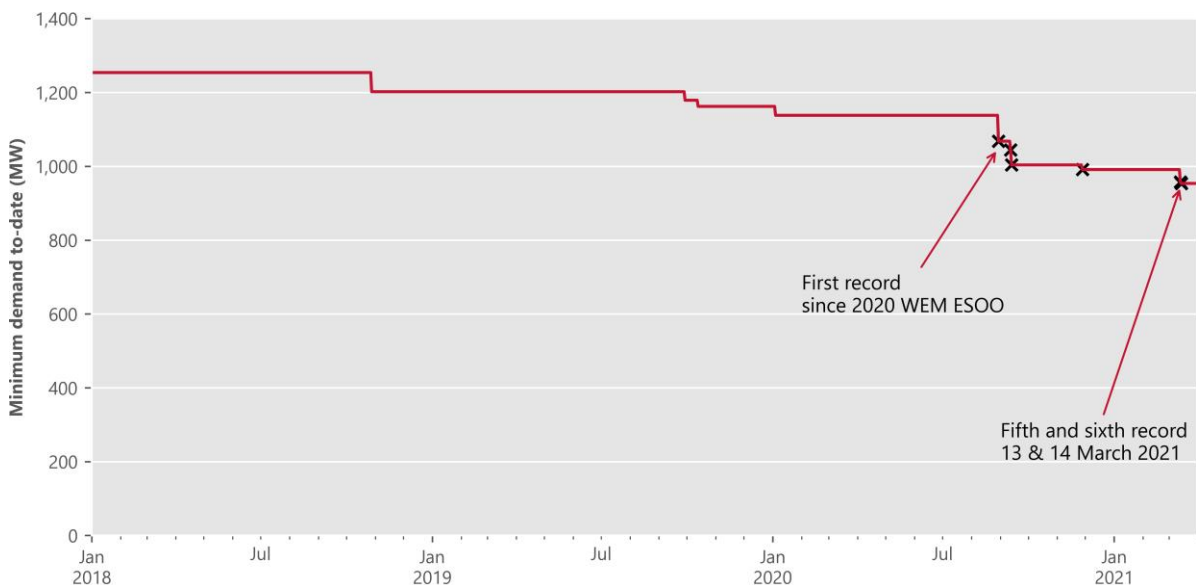
A. Demand reduction from behind-the-meter PV at the time of recorded minimum demand.

B. Temperature at the time of minimum demand on 13 March 2021 was 23.8°C (Trading Interval 12:30 to 13:00) and on 14 March 2021 was 25.4°C (Trading Interval 11:30 to 12:00).

Source: AEMO, BOM, CER and Solcast.

As shown in Figure 16, the record for minimum demand is continually being set. The primary driver of this is the continued uptake of behind-the-meter PV in the SWIS.

Figure 16 Minimum demand since WEM start, January 2018 to March 2021



Source: AEMO.

As the number of behind-the-meter PV installations continues to grow, AEMO expects that new minimum demand records will continue to be set. As these low demand levels continue, management of the SWIS will become increasingly challenging. AEMO is aware of the need for market and operational intervention to

ensure the system stays secure and stable⁶³. AEMO is actively addressing these issues through the WA DER Roadmap in conjunction with Energy Policy WA and Western Power. Chapter 7 contains more details on the minimum demand challenges and the work being undertaken to alleviate the associated risks on the system.

3.3 Historical energy consumption

This section on historical energy consumption investigates the total operational and underlying consumption, consumption by sector and residential consumption, for the period 2012-13 to 2019-20 in the SWIS. All data in this section is presented in Capacity Years unless otherwise specified.

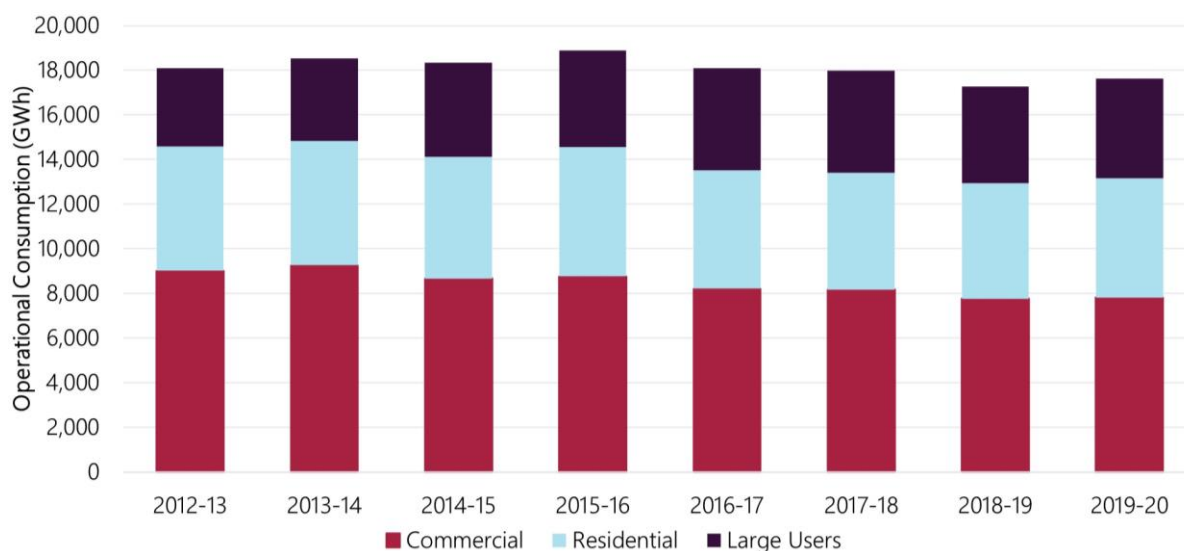
3.3.1 Operational consumption by sector

Figure 17 shows total operational consumption between 2012-13 and 2019-20, broken down into commercial, residential, and large users.

Total operational consumption increased at an average annual rate of 1.5% from 2012-13 to 2015-16, mostly as a result of growth in large users (including desalination plants and large mines) of 7.3% annually. Since 2015-16, total operational consumption has declined steadily, at an average annual rate of 1.7%. The overall decline in total operational consumption was driven by behind-the-meter PV generation, as demonstrated by the reduction in residential and commercial operational consumption shown in Figure 17.

Over the entire period of analysis, 2012-13 to 2019-20, the percentage contribution of commercial and residential to total operational consumption decreased consistently, from 81% to 75%, while large user consumption increased from 19% to 25%. Large user consumption has grown in most years with the exception of 2017-18 and 2018-19 (a decline of 0.3% and 5.4% respectively). The decline in 2018-19 was a result of heavy storms which caused significant maintenance outages at large mines. The most significant annual growth in large user consumption (13.6%) was between 2013-14 and 2014-15.

Figure 17 Annual operational consumption by sector, 2012-13 to 2019-20



Source: AEMO and Synergy.

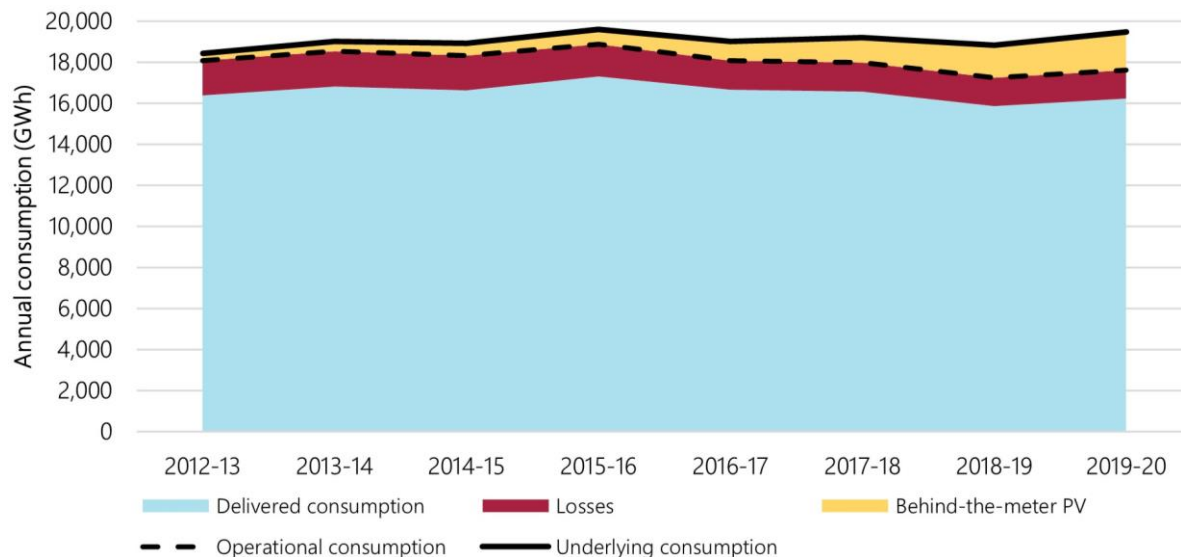
3.3.2 Total consumption breakdown

Figure 18 shows the breakdown of historical consumption, representing both electricity consumed from the SWIS and generation from behind-the-meter PV and an estimate of losses. Underlying consumption increased at an average annual rate of 0.8%, while delivered consumption shows a small decline at an

⁶³ For more information on minimum demand and what is being done to mitigate those challenges, see <https://aemo.com.au/learn/energy-explained/energy-101/energy-explained-minimum-operational-demand>.

average annual rate of 0.2%. Consumption being met by behind-the-meter PV⁶⁴ is the main driver of reduced delivered consumption. Behind-the-meter PV generation increased by 421%, from 362 GWh in 2012-13 to 1,883 GWh in 2019-20.

Figure 18 Total consumption breakdown, 2012-13 to 2019-20



Source: AEMO, CER and Solcast.

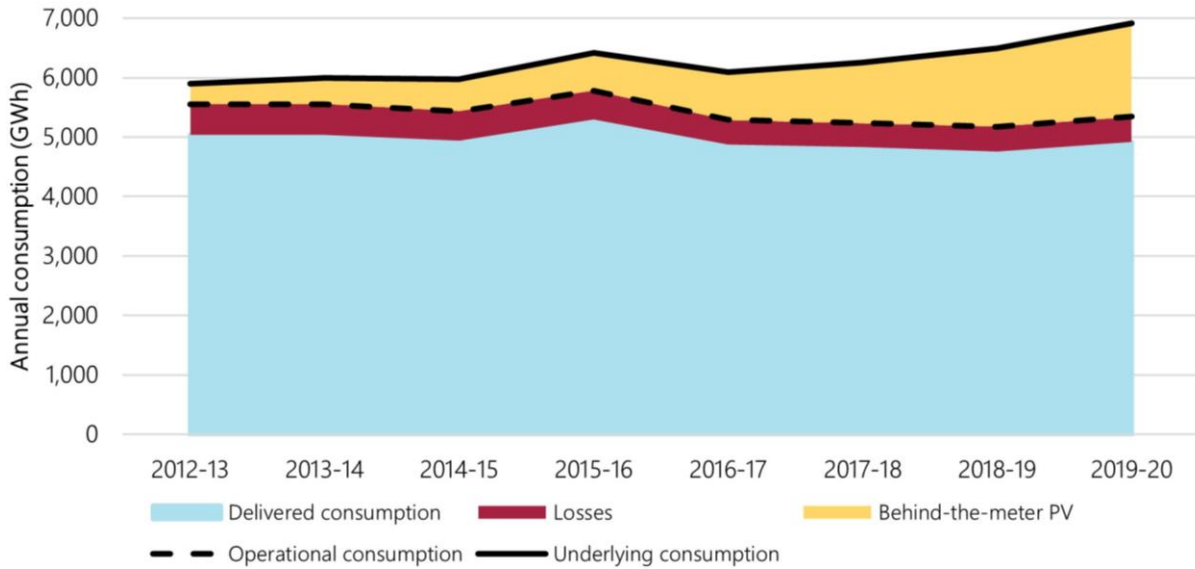
3.3.3 Residential consumption breakdown

AEMO calculated the breakdown of residential consumption over the period 2012-13 to 2019-20, as shown in Figure 19. This includes energy delivered to customers from the SWIS, combined with energy supplied by residential behind-the-meter PV generation and an estimate of losses.

Delivered residential consumption shows a small decline over time at an average annual rate of 0.3%, despite an increase in underlying residential consumption (annual increase of 2.3%). This is driven largely by significant growth in behind-the-meter PV. The share of residential consumption met by residential behind-the-meter PV generation has almost quadrupled, from 6% in 2012-13 to 23% in 2019-20.

⁶⁴ This is consumption that otherwise would have been imported from the SWIS grid.

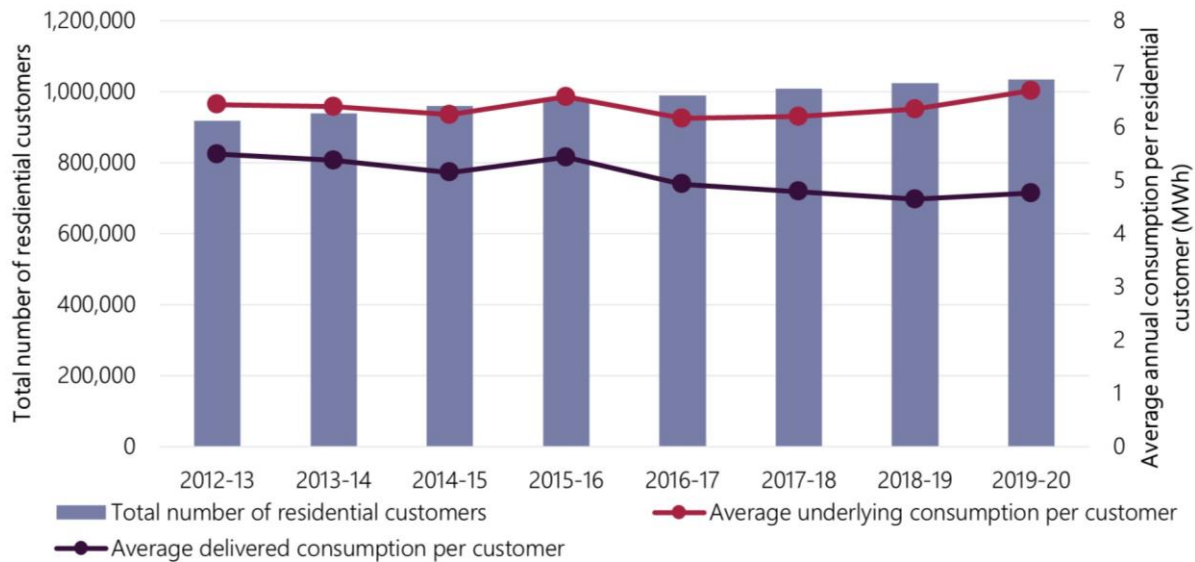
Figure 19 Residential consumption breakdown, 2012-13 to 2019-20



Source: AEMO, CER, Solcast and Synergy.

The underlying consumption per customer rose steadily at an average annual rate of 0.6% throughout the entire period, while the delivered consumption per customer decreased at 2.0%, from 5.5 MWh in 2012-13 to 4.8 MWh in 2019-20, as shown in Figure 20. Underlying consumption per residential customer increased by 5.5% in 2019-20, which is most likely attributable to an increased number of people working from home during the COVID-19 pandemic.

Figure 20 Consumption per residential customer, 2012-13 to 2019-20



Source: AEMO calculations based on data provided by Synergy.

4. Distributed energy resources trends and forecasts

At over 36%, WA's behind-the-meter PV uptake per capita is among the highest in the world. During daylight hours, with clear sky conditions, behind-the-meter PV is the largest single generator in the SWIS. In the 2020 calendar year, there was a 25.3% increase in installed behind-the-meter PV capacity, while battery storage⁶⁵ capacity in the SWIS nearly doubled. As of April 2021, there was 1.74 GW of behind-the-meter PV installed in the SWIS.

The adoption of electric vehicles (EVs) is expected to pick up pace across the outlook period with more than 99,000 EVs projected to be on the road by 2030-31.

This chapter focuses on the pace of DER uptake in recent years and DER forecasts for the outlook period.

4.1 Historical DER uptake trends

4.1.1 Total number of DER installations and total capacity

As shown in Figure 21, year-on-year PV installations have grown at a relatively steady pace since 2015, while behind-the-meter battery installations continue their post-2017 rapid growth trend.

As of April 2021, the generation capacity of residential and small commercial⁶⁶ PV installations has reached a total of 1.74 GW⁶⁷, which represents a capacity greater than the sum of the largest six Scheduled Generators in the SWIS⁶⁸. More than 379,000 systems have been installed⁶⁹ and over 36%⁷⁰ of WA dwellings have behind-the-meter PV installations.

The DER Register includes battery storage installations in the SWIS dating back to 2008. The introduction of the feed-in tariff⁷¹ scheme coincides with a spike in battery installations between July 2010 and August 2011, with no further significant increases until 2017. As reported in the DER Register, as of April 2021, total residential and commercial battery storage capacity exceeds 12.8 MWh.

More customers are choosing to install behind-the-meter PV and battery storage at the same time. Policy changes aiming to shift customers from a flat export tariff to a time-of-use tariff resulted in the WA State

⁶⁵ Battery storage refers to batteries that operate behind-the-meter.

⁶⁶ Includes installations larger than 100 kilowatts (kW) that are not registered as Facilities in the SWIS.

⁶⁷ PV installations as at April 2021 based on Clean Energy Regulator (CER) data.

⁶⁸ Refer to Table 33.

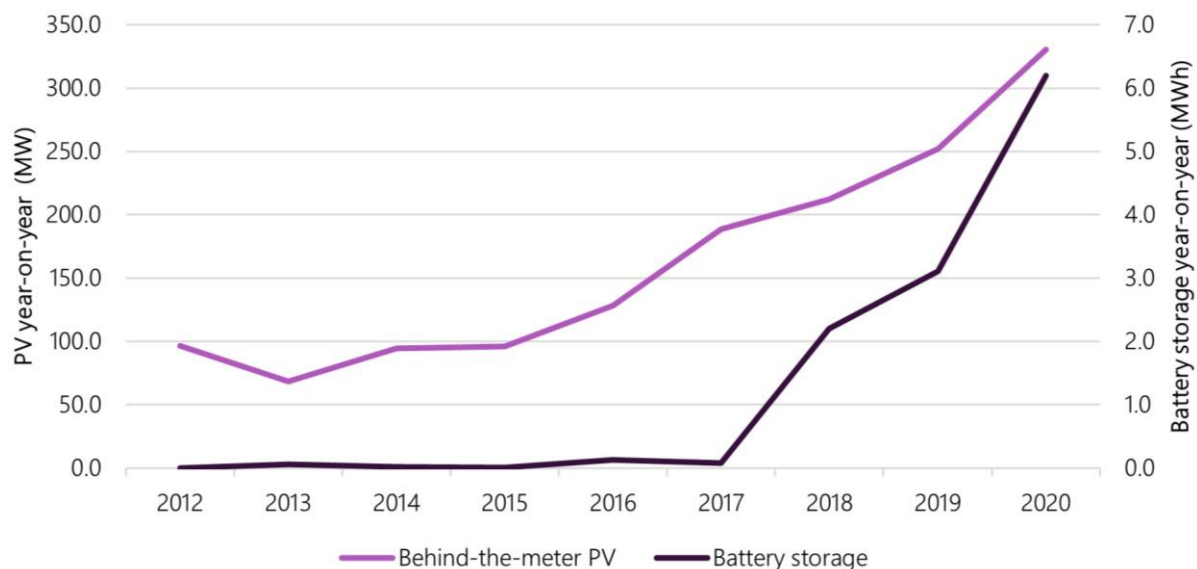
⁶⁹ Installation figures are based on values provided by the CER with minor adjustments made by AEMO.

⁷⁰ Based on SWIS connections estimate.

⁷¹ See <https://www.synergy.net.au/Global/FIT-Faq>.

Government’s launch of the Distributed Energy Buyback Scheme (DEBS)⁷² on 31 August 2020. The new buyback scheme is part of the DER Roadmap⁷³ Tariffs and Investment Signals workstream, which aims to incentivise customers to shift their energy use to the middle of the day when there is excess behind-the-meter PV generation. Time-of-use tariffs can provide cost-reflective pricing signals that reflect the costs to service the peak.

Figure 21 Year-on-year growth in behind-the-meter PV and battery storage, 2012-20^A



A. Behind-the-meter PV data from the Clean Energy Regulator (CER), for each calendar year, with minor adjustments by AEMO. Battery storage installation data from the DER Register⁷⁴.

4.1.2 Installed DER system size trends

The early behind-the-meter PV system average size was 1.2 kilowatts (kW) up until 2009, and increased to 3 kW by 2013. Since 2014 there has been a strong trend to install larger systems, shown in Figure 22, with behind-the-meter PV arrays up to 33%⁷⁵ larger than the inverter size. The larger systems allow for greater generation when solar conditions are not ideal due to cloud cover, installation angle, or panel degradation. Another driver for panel over-sizing is the maximisation of upfront rebates in the form of Small-scale Renewable Energy Scheme⁷⁶ certificates, since the scheme calculates the total system export capability based on installed panel size. With the maximum permitted inverter size of 5 kilovolt-amperes (kVA)⁷⁷, the average installed behind-the-meter PV system increased significantly in 2019 toward the maximum allowable panel size of 6.6 kW.

Systems larger than 10 kW continue to be installed, although at a much slower rate than the 5-10 kW systems. These systems are permitted for three-phase connections, and are more commonplace for commercial installations.

⁷² See <https://www.synergy.net.au/Your-home/Manage-account/Solar-connections-and-upgrades/Distributed-Energy-Buyback-Scheme>.

⁷³ See <https://www.wa.gov.au/government/publications/der-roadmap>.

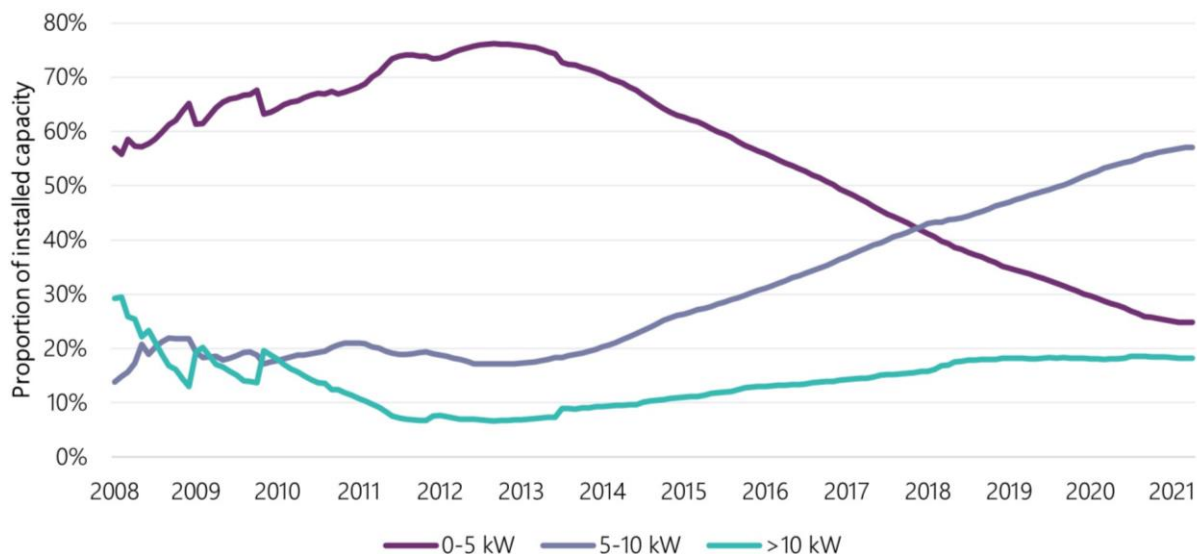
⁷⁴ See <https://aemo.com.au/energy-systems/electricity/der-register/data-der/data-dashboard>.

⁷⁵ According to the Clean Energy Council Accreditation Guidelines, at <https://www.cleanenergycouncil.org.au/industry/installers/compliance-toolkit/accreditation-guidelines>.

⁷⁶ See <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works/Small-scale-Renewable-Energy-Scheme>.

⁷⁷ DEBS information, at <https://www.synergy.net.au/Your-home/Manage-account/Solar-connections-and-upgrades>.

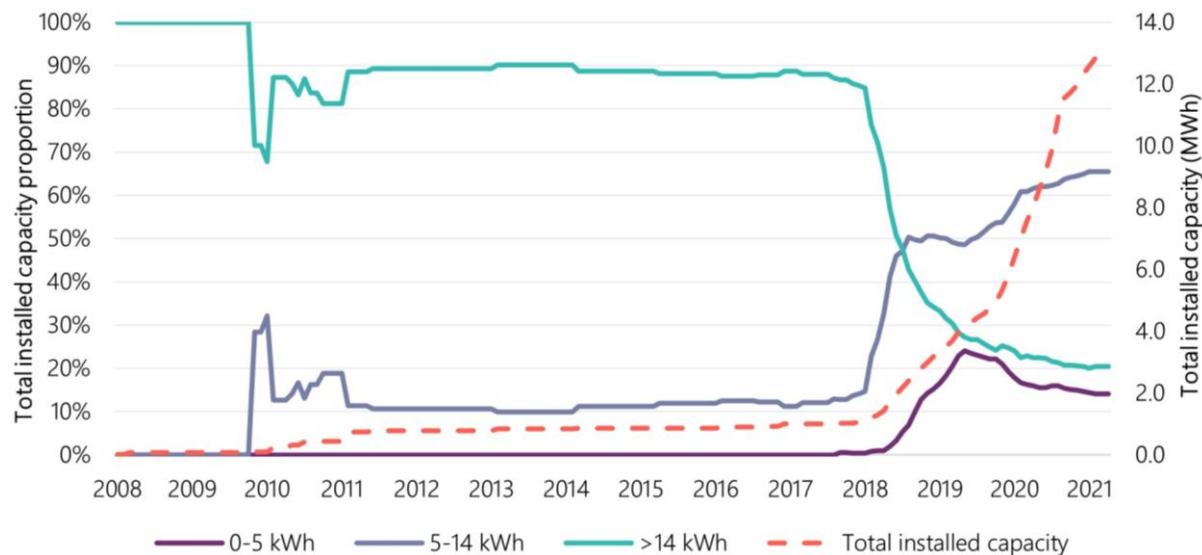
Figure 22 Proportion of installed generation capacity, by behind-the-meter PV system size, 2008 to 2021^A



A. Data as of April 2021, DER Register (for each calendar year).

Figure 23 shows the mix of installed residential and commercial behind-the-meter storage capacity in the SWIS. While initial growth in battery storage was dominated by systems larger than 14 kilowatt hours (kWh), the installation of these larger systems has since declined, as has installation of systems smaller than 5 kWh. The 5-14 kWh systems are now the fastest growing and most dominant segment of the market, and the vast majority of residential battery storage units on the market today are in this size range.

Figure 23 Proportion of installed battery storage, by system size, 2008 to 2021^A



A. Data as of April 2021, DER Register (for each calendar year).

4.1.3 Monthly DER installation rate trends

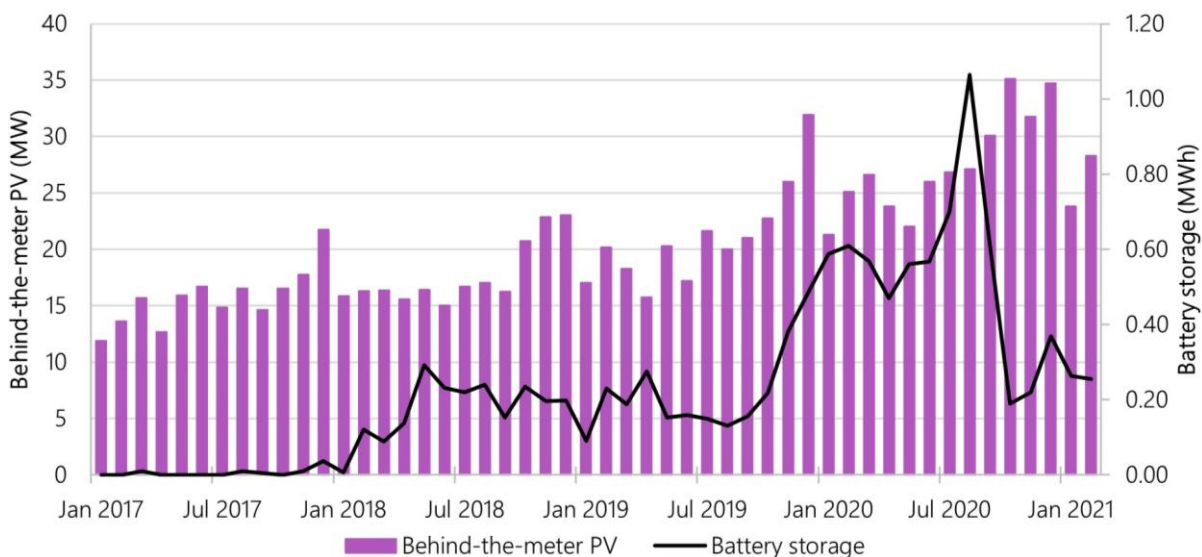
Through the WA Government’s DER Roadmap, WA now has a SWIS-specific database of DER installations. The WEM DER Register provides transparency in the adoption rates of both behind-the-meter PV and battery storage.

As Figure 24 shows, the WEM DER Register reveals a strong uptick in the number of monthly installations of both behind-the-meter PV and battery storage in the second half of the 2020 calendar year.

In 2020, the average monthly installation rate of:

- Behind-the-meter PV was 27.5 MW per month, and the installation rate reached a peak in October with more than 35.1 MW installed.
- Battery storage was 543.2 kWh per month, and the installation rate reached a peak in August with more than 1 MWh installed.

Figure 24 Monthly installed capacity of behind-the-meter PV and battery storage, 2017 to 2021^{A,B,C}



- A. Monthly capacity as of April 2021, DER Register. Data after February 2021 removed due to integrity issues.
 B. Note that there is a reporting lag in the January 2021 installed capacity.
 C. Energy is a measure of power over time, so the quantity of stored energy is measured in MWh.

4.1.4 Dual technology trends

There is an evolving trend towards combining installations of behind-the-meter PV and battery storage. Before 2020, approximately 1.3% of customers installed both behind-the-meter PV and battery storage, but by the end of 2020, this had risen to approximately 2.0% of customers.

Further investigation highlights that households and businesses are installing larger battery storage in combination with their behind-the-meter PV installations.

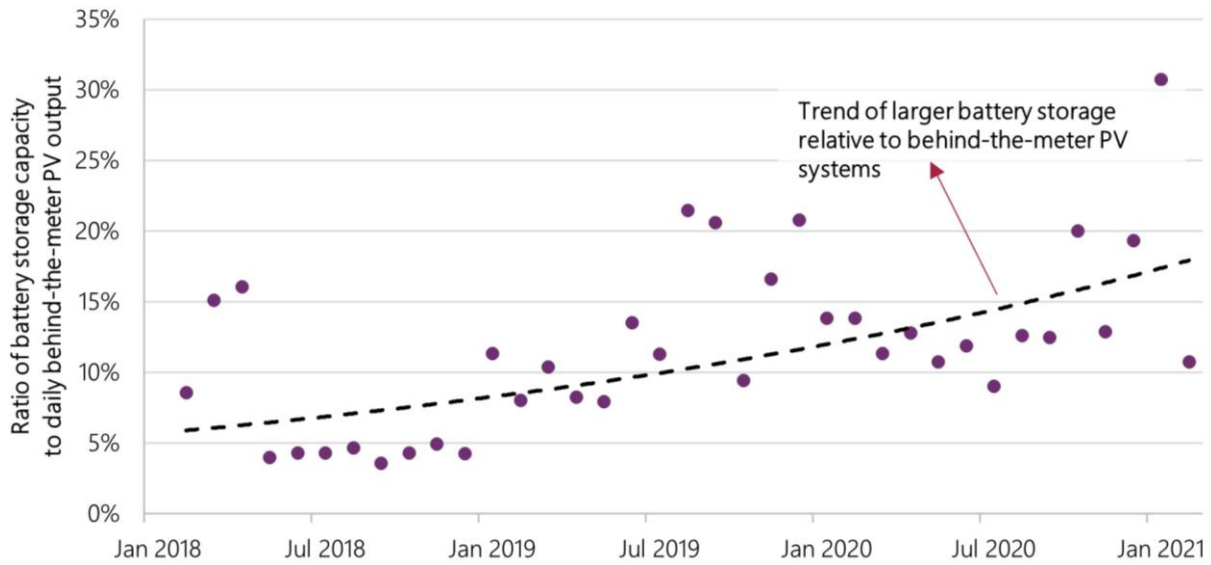
Figure 25 illustrates that in 2018, installed battery storage could accommodate only 5% of the potential solar generation for that connection point, while by 2021, consumers were opting for larger battery storage, sized to hold more than 15% of the potential solar generation for that connection point.

Rather than exporting excess behind-the-meter PV generation to the grid, customers can use this dual technology approach to store power for later use, reducing usage charges on their bill. This could be beneficial from a system stability perspective, as battery storage has the potential to soak up excess behind-the-meter PV generation.

As part of the DER Roadmap⁷⁸, the DER orchestration pilot (Project Symphony) will test the capability of a virtual power plant (VPP) to respond in a coordinated manner under central dispatch instructions, with the aim of determining an optimised battery charging profile with respect to grid load.

⁷⁸ See https://www.wa.gov.au/sites/default/files/2020-04/DER_Roadmap.pdf.

Figure 25 Trend of potential^A daily behind-the-meter PV generation^B relative to installed battery storage, 2018 to 2021

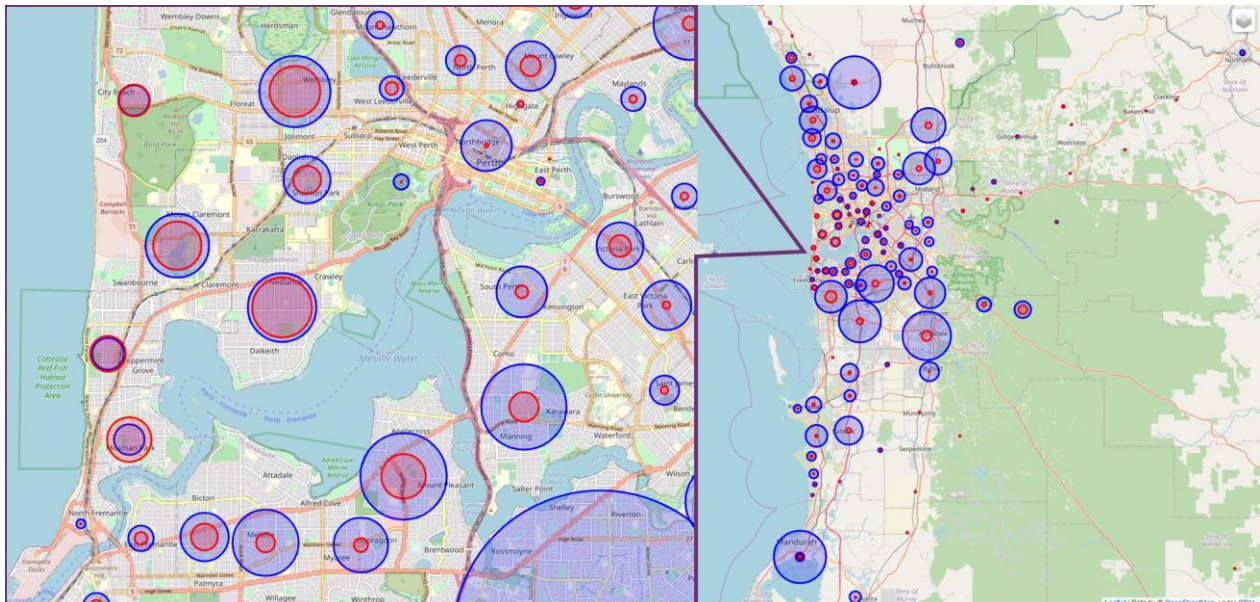


A. Based on an assumed daily behind-the-meter PV generation of 4.65 kWh per kW per day for Perth. For a 5 kW system, this equates to approximately 23 kWh generated per day. If a 23 kWh battery storage was connected to this generation system, the ratio would be 100%.
 B. Analysis is restricted to dual technology installations with behind-the-meter PV systems sized between 5 kW and 10 kW.

4.1.5 DER locational trends

Locational trends highlight strong adoption of behind-the-meter PV in newer residential developments, which tend to be concentrated in the outer metropolitan area of Perth. Furthermore, residential growth along the north coast correlates well with high behind-the-meter PV uptake.

Figure 26 Behind-the meter PV and battery storage postcode aggregations^{A,B}



A. Bubbles illustrate the proportion of installed capacity (at postcode level) for behind-the-meter PV (blue) and battery storage (red) relative to the total installed capacity in the SWIS. Larger bubbles reflect a higher number of behind-the-meter installations for that postcode compared to other postcodes across the SWIS.
 B. Data as of April 2021, DER Register.

In contrast, uptake of battery storage is higher in more established areas. Lower affordability and longer payback periods – currently exceeding the assets’ warranty periods – tend to restrict their use to higher

disposable income households. There has been substantial uptake of battery storage in the Perth suburbs of Dalkeith, Peppermint Grove, Mosman Park, and Mount Claremont.

Areas outside of Perth’s metropolitan area, where power supply reliability is lower, contain installations of relatively large battery storage compared to the accompanying behind-the-meter PV capacity.

4.2 DER forecasts

AEMO commissioned two external consultants to develop DER forecasts:

- The Commonwealth Scientific and Industrial Research Organisation (CSIRO) developed behind-the-meter PV, battery storage, and EV⁷⁹ uptake forecasts.
- Green Energy Market’s (GEM’s) forecasts covered behind-the-meter PV and battery storage⁸⁰.

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

WEM DER forecasts were developed (as part of forecasts for Australia) for multiple scenarios which were mapped to the three demand growth scenarios: low, expected, and high⁸¹. Table 10 shows the allocation of the two consultants’ DER forecasts to the low, expected, and high scenarios.

Table 10 Consultant DER forecast to scenario mapping

	Low	Expected	High
Behind-the-meter PV	GEM Slow Growth	Average of CSIRO and GEM Current Trajectory	CSIRO Rapid Decarbonisation
Behind-the-meter battery storage	GEM Slow Growth	Average of CSIRO and GEM Current Trajectory	CSIRO Rapid Decarbonisation
EVs	CSIRO Slow Growth	CSIRO Current Trajectory	CSIRO Rapid Decarbonisation

A summary of the DER forecast results and methodologies is presented below. Further details on the methodology and assumptions for the DER forecasts are in the CSIRO and GEM reports⁸².

4.2.1 Behind-the-meter PV forecasts

CSIRO and GEM developed monthly behind-the-meter PV installed capacity forecasts for residential (≤ 10 kW), small commercial (10 kW to 100 kW), and large commercial (100 kW to 10 MW) PV installations⁸³.

At a high level, the methodologies were:

- CSIRO used a combination of techniques across the outlook period. Up to the end of the 2022 calendar year, CSIRO used trend-based modelling to capture recent growth trajectories. For PV systems under

⁷⁹ CSIRO, Small-Scale Solar and Battery Projections 2021, see https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf?la=en; CSIRO, Electric Vehicle Projections 2021, see https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf?la=en.

⁸⁰ 2021 GEM DER report, see https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en.

⁸¹ Low, expected, and high demand growth scenarios are named slow growth, current trajectory, and rapid decarbonisation respectively in CSIRO’s and GEM’s reports. In addition to these scenarios, CSIRO and GEM developed forecasts for net zero, sustainable growth, and export superpower scenarios. These scenarios were not used in this 2021 WEM ESOO. See CSIRO and GEM’s reports, and the appendix of the Inputs Assumptions and Scenarios Report Consultation Feedback slide pack, see <https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr-consultation-feedback.pdf?la=en> for further information.

⁸² At <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities>.

⁸³ Classified in the NEM as PV Non-Scheduled Generators (PVNSG).

100 kW, CSIRO 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.

COVID-19 adjustments have not been made, since behind-the-meter PV and battery storage uptake has remained strong despite the pandemic. Current trends point to a higher short-term DER uptake.

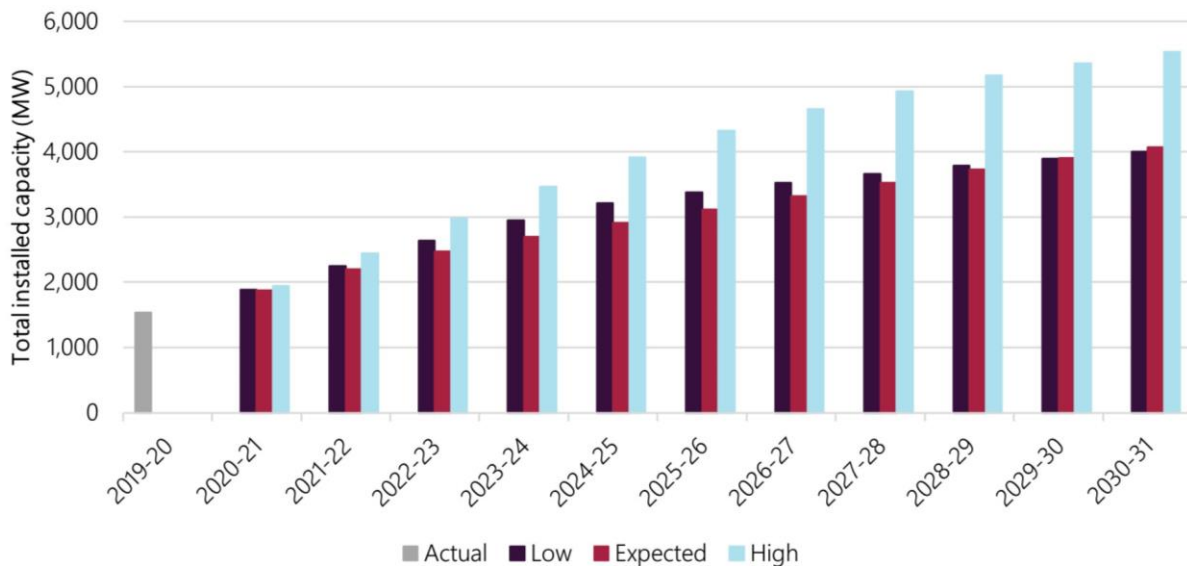
The behind-the-meter PV forecasts account for technological developments that may take place during the forecast outlook period. Rapid advancement in PV module development is leading to increasingly powerful⁸⁴ and efficient panels. AEMO continues to monitor emerging progress in PV technology.

Installed capacity forecasts

Figure 27 shows the forecast⁸⁵ uptake of total behind-the-meter PV in the SWIS under the low, expected, and high demand growth scenarios. Installed behind-the-meter PV capacity is forecast to grow:

- Under the low demand growth scenario at an average annual rate of 7.8%, to reach 4,003 MW by 2030-31, up from 1,885 MW in 2020-21.
- Under the expected demand growth scenario at an average annual rate of 8.0%, to reach 4,069 MW by 2030-31, up from 1,877 MW in 2020-21.
- Under the high demand growth scenario at an average annual rate of 11.0%, to reach 5,531 MW by 2030-31, up from 1,941 MW in 2020-21.

Figure 27 Actual and forecast installed behind-the-meter PV capacity, 2019-20 to 2030-31



Source: CSIRO and GEM.

The 10-year average annual growth rates for all scenarios are significantly higher than the 2020 WEM ESOO forecasts, with the key changes summarised as follows:

⁸⁴ Recently, manufacturers have been releasing 'ultra-high power' commercial PV panels that exceed 600 watts (W) in capacity.

⁸⁵ Forecasted behind-the-meter PV values are inclusive of expected 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.

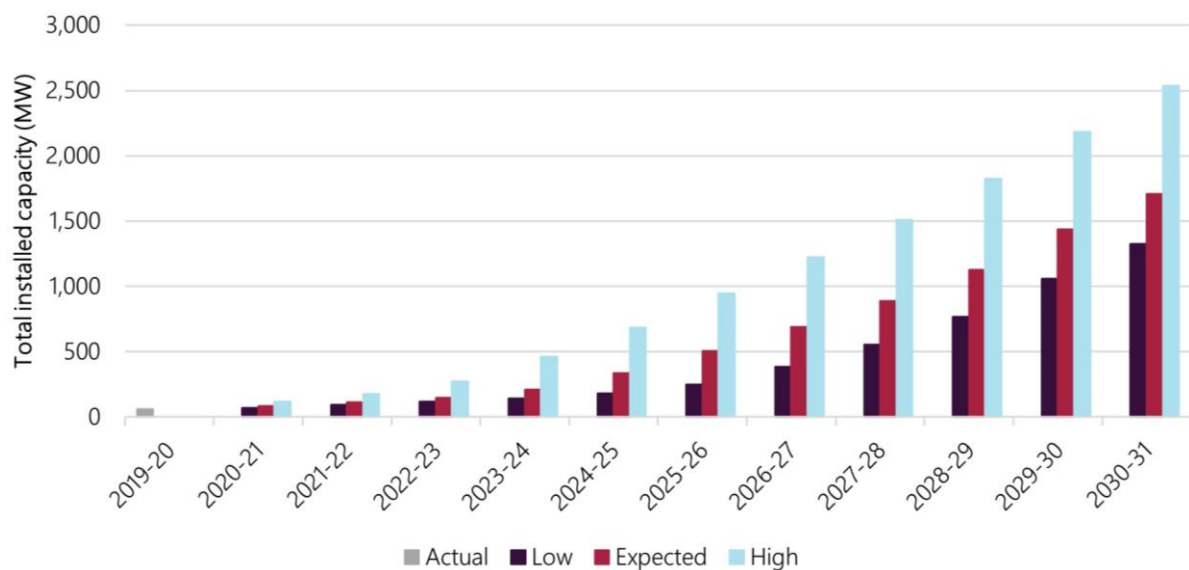
- In the low demand growth scenario, the 10-year average growth is forecast to be 7.8% compared to the 2020 WEM ESOO forecast of 3.2%. The low demand growth scenario starts out higher than the expected demand growth scenario due to stronger response to short-term targeted stimulus to aid recovery from the COVID-19 pandemic. Additionally, in this scenario, projected lower interest rates and borrowing costs results in higher levels of behind-the-meter PV uptake over the next 10 years⁸⁶. These two factors were expected to moderate towards the end of the outlook period.
- Under the expected demand growth scenario, behind-the-meter PV growth is forecast to be 8.0% compared to the 2020 forecast of 6.5%. In the 2020 forecast, the COVID-19 pandemic was expected to limit behind-the-meter PV installations, however installation rates increased. Any COVID-19 related impacts were removed from the forecast and only the last two years of historical data were used for the short-term trend model (up to the end of 2022). Expected further cost reductions for behind-the-meter PV were factored-in to increase installations.
- The forecast annual growth rate for the high demand growth scenario is 11.0%, compared to the 2020 forecast of 9.5%, mainly due to the strong growth used in the trend model and increased electrification of other sectors.

4.2.2 Behind-the-meter battery storage forecasts

Behind-the-meter battery storage forecasts assumed each residential battery storage installation was paired with a behind-the-meter PV system to minimise electricity imports from the grid. At a high level, the assumptions and methodologies are similar to those adopted for forecasting behind-the-meter PV uptake (see Appendix A2).

The battery storage installed capacity forecasts for the low, expected, and high demand growth scenarios are shown in Figure 28. Under the expected demand growth scenario, the installed storage capacity of battery systems in the SWIS is projected to increase at an annual average rate of 34.8%, from 86 MWh in 2020-21 to 1,708 MWh in 2030-31. The high growth rate is primarily attributed to the projected reduction in the cost of battery systems over the forecast period.

Figure 28 Actual and forecast installed capacity of battery storage (behind-the-meter)^A, 2019-20 to 2030-31



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.

⁸⁶ This assists with exploring system security risks associated with higher penetration of behind-the-meter PV and corresponding declines in minimum demand. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?a=en.

In the 2021 WEM ESOO, both consultants have considered external sources for estimating the number of batteries currently installed in the SWIS. Consequently, the forecast commences from a different (higher) base in 2020-21 compared to the number of installations currently detailed in the DER register (approximately 2,000). This discrepancy is relatively minor compared to the forecast growth in installations. AEMO expects to switch to solely referencing the DER Register for developing forecasts in the future.

Battery discharge profiles

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. 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.

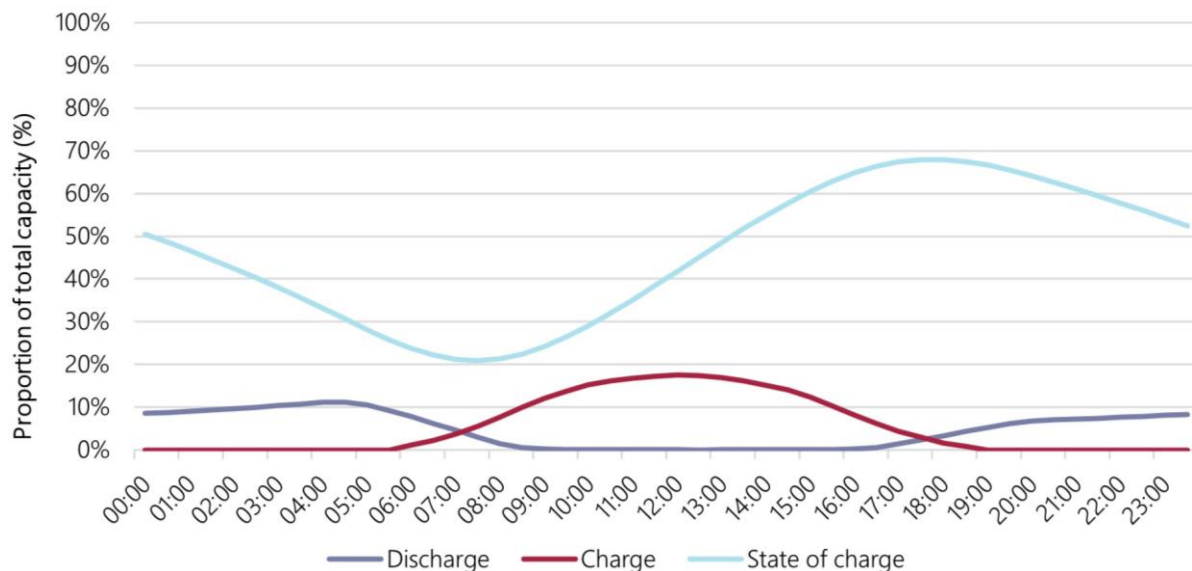
The peak demand forecasts consider operation of behind-the-meter batteries under a combination of flat and time-of-use tariffs. Batteries are assumed to operate to minimise household/commercial business electricity costs without consideration of whether the aggregate outcome is optimised for the electricity system. Under the solar shifting algorithm (flat tariff), customers' batteries:

- 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 some energy from daytime periods to be consumed during the evening household peak, offsetting peak consumption for the customer.

The modelled profile in Figure 29 was generated by CSIRO using PV generation data and household half-hourly demand data, and shows the average February daily charging and discharging pattern for residential customers.

Figure 29 Modelled daily residential battery charging profile (flat tariff)^A



A. Normalised battery charging profile, averaged for February 2019 and February 2020, discharging and state of charge (as a % of total capacity) modelled with no aggregated response.

Source: CSIRO.

Battery displacing operational consumption

The 2021 WEM ESOO continues to use the assumption 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 losses⁸⁷, 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 EV uptake forecasts

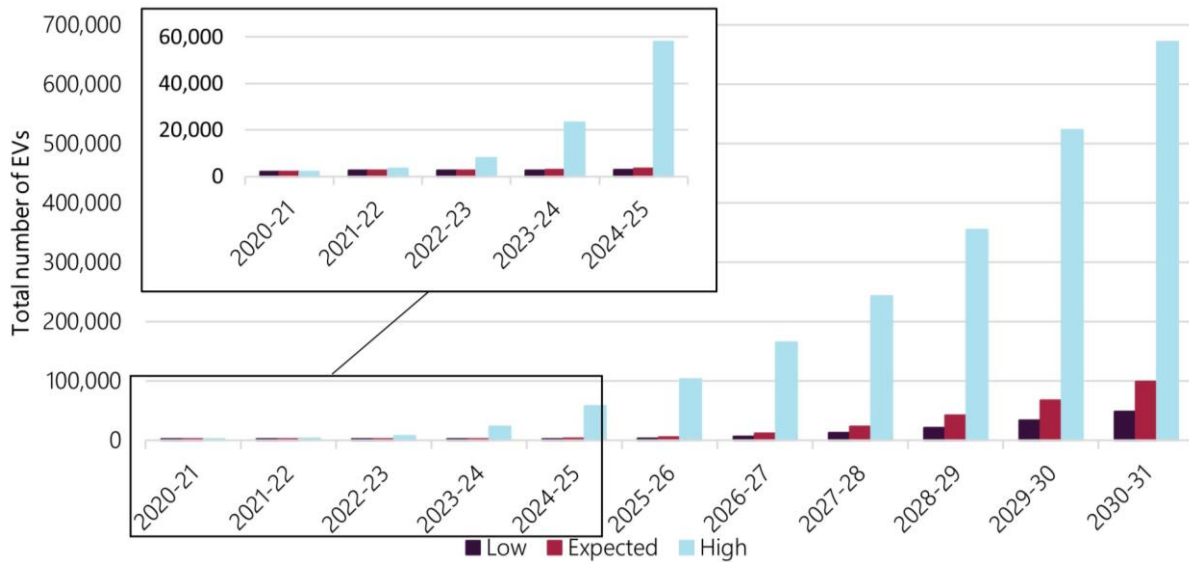
CSIRO developed the forecasts for battery EVs (BEVs) and plug-in hybrid EVs (PHEVs). For each type, CSIRO projected EV uptake for vehicle classes including residential, light commercial, and heavy commercial such as buses and trucks. Forecast EV numbers in the SWIS are shown in Figure 30.

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

The range between the high and low demand growth scenarios is due to:

- Different cost projections applied, 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 demand growth scenario, EV forecasts are comparatively higher, as it is assumed WA will move towards a zero-emission road transport sector by 2050, allowing the EV sales share to grow to 100% by 2040⁸⁸ in most vehicle classes.

Figure 30 Forecast total number of EVs, 2020-21 to 2030-31^A



A. Includes BEVs and PHEVs. BEVs have electric motors (that are solely battery-powered), while PHEVs have both petrol engines and electric motors. Both BEVs and PHEVs can recharge their batteries at a power outlet.

Source: CSIRO.

⁸⁷ Depending on the technology type of battery storage, the typical round-trip efficiency of energy storage in batteries can range between 70% to 95%.

⁸⁸ While long-term policy implications are considered in shaping the forecast, the forecast is limited to the 10-year outlook period.

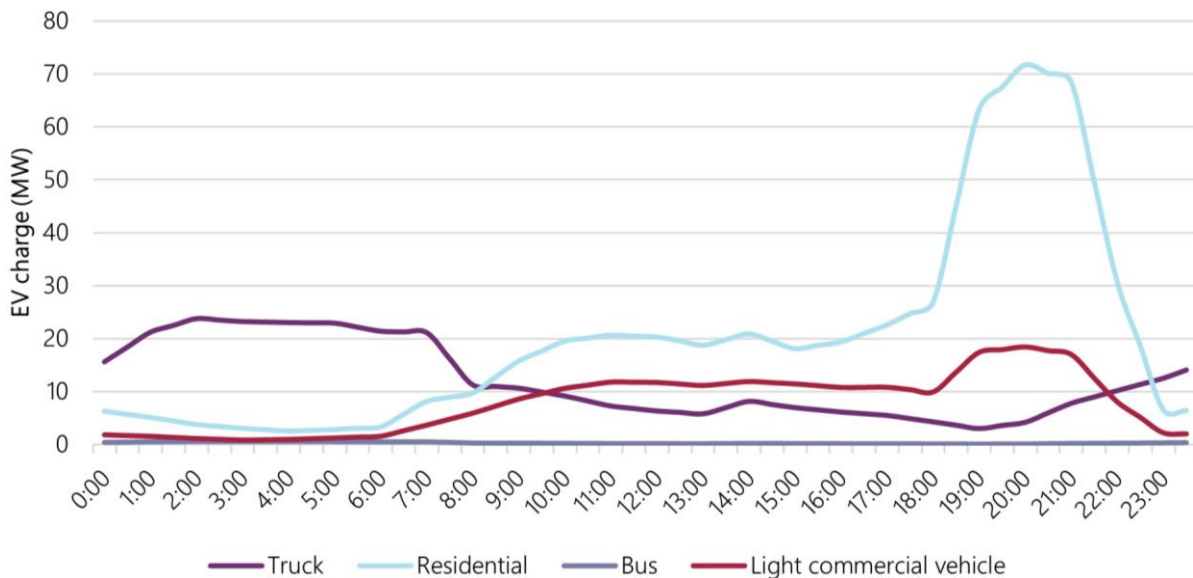
EV charging profiles

The impact of EVs on peak demand is shown in Figure 31, and depends on the number of EVs charging at the time of peak demand⁸⁹.

CSIRO developed four EV charge profiles, defined as follows:

- **Convenience charging** refers to charging of EVs that are assumed to have no incentive to charge at specific times.
- **Fast charging or highway charging** is based on studies from China, where deployment is widespread, and utilisation of fast charging or highway charging has been observed.
- **Day charging** with a higher proportion (relative to night charging) expected in the long-term in response to incentives to charge when behind-the-meter PV generation is at its highest.
- **Night charging** with a higher proportion (relative to day charging) expected in the short term.

Figure 31 Daily weekday EV charging profiles, June 2031



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.

⁸⁹ This is calculated as the forecast number of EVs multiplied by a charge profile specific to the vehicle 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.

5. Peak demand, minimum demand, and consumption forecasts

This chapter presents peak demand and operational consumption forecasts for the outlook period 2021-22 to 2030-31. Minimum demand forecasts are presented for a five-year outlook period. In summary:

- Peak demand⁹⁰ is forecast to increase at an average annual rate of 0.2% across the 10-year outlook period in the expected demand growth scenario.
- Operational consumption is forecast to decline at an average annual rate of 0.8% in the expected demand growth scenario, primarily due to increased consumption from behind-the-meter PV.
- Minimum demand is forecast to decline rapidly to 232 MW⁹¹ by 2025-26 in the expected demand growth scenario, predominantly due to growth in behind-the-meter PV installations.

Forecasts are presented for three demand growth scenarios: low, expected, and high. These scenarios reflect different projections of economic and population growth, large industrial loads (LILs), energy efficiency improvements, and DER uptake rates⁹².

For each of the three demand growth scenarios, the peak demand forecasts have been modelled under three probabilistic outcomes – 10%, 50%, and 90% probability of exceedance (POE)⁹³. These probabilistic outcomes capture variation due to unpredictable drivers such as weather (primarily temperature), seasonal effects, and random stochastic volatility (see Appendix A2).

Minimum demand forecasts are presented for the expected demand growth scenario under three probabilistic outcomes.

In this chapter:

- All data is presented in Capacity Years unless otherwise specified.
- Demand refers to operational demand unless otherwise stated.
- No limitations were applied to uptake of behind-the-meter PV.

⁹⁰ Peak demand based on a 10% POE.

⁹¹ Minimum demand based on a 50% POE.

⁹² For the 2020 WEM ESOO, the expected scenario behind-the-meter PV and battery storage forecasts were applied to the peak demand and operational consumption forecasts in all three demand growth scenarios. However, in the 2021 WEM ESOO, the modelling used different DER (behind-the-meter PV, battery storage, and EV) forecasts in each demand growth scenario to better illustrate a wider range of possible outcomes, particularly for minimum demand.

⁹³ For demand forecasts, a 10% POE represents a 1-in-10-year chance of exceedance, a 50% POE represents a 1-in-2-year chance of exceedance and the 90% POE represents a 9-in-10-year chance of exceedance.

- Forecasts refer to the expected demand growth scenario unless otherwise stated.
- Battery storage refers to batteries that operate behind-the-meter.

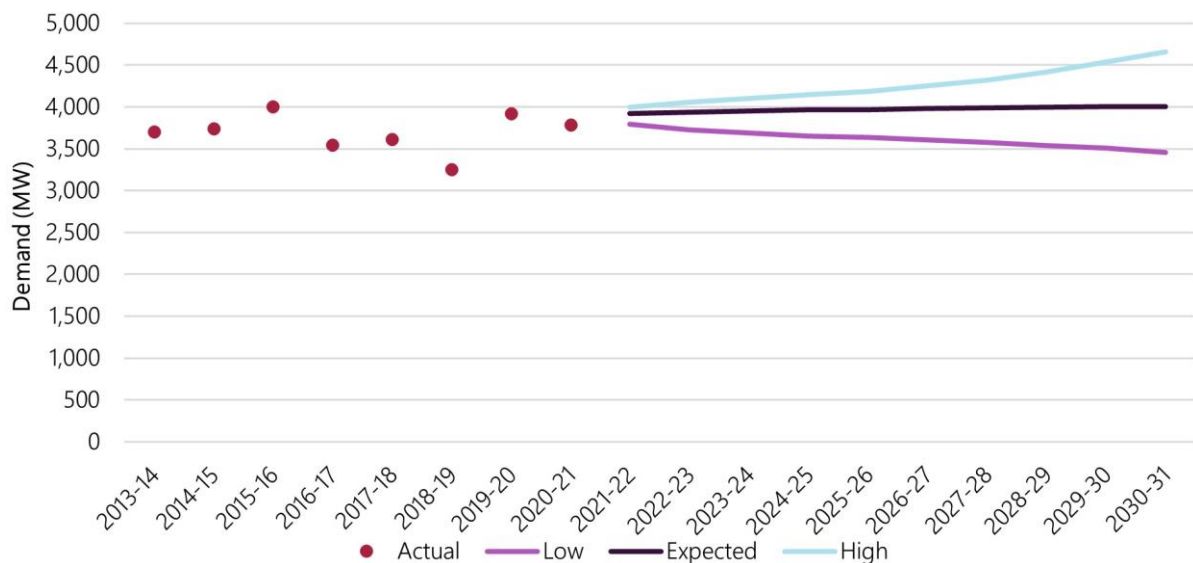
5.1 Peak demand forecasts

5.1.1 Annual peak demand forecasts

Figure 32 shows the 10% POE peak demand forecasts under the three demand growth scenarios, alongside actual peak demand from 2013-14 onwards. In summary:

- In the **low demand growth scenario**, peak demand is forecast to decline at an average annual rate of 1.0%, primarily as a result of falling demand in the business sector⁹⁴. The pace of decline is expected to accelerate in the second half of the outlook period as battery storage discharge during peak periods.
- In the **expected demand growth scenario**, peak demand is forecast to increase at an average annual rate of 0.2%, as a result of increased load from the residential and business sectors combined with EV charging, partially offset by demand reduction from battery storage discharge at the time of peak.
- In the **high demand growth scenario**, peak demand is forecast to increase at an average annual rate of 1.7%, largely driven by EV charging, as well as strong growth in demand from the business sector.

Figure 32 10% POE forecast peak demand under three demand growth scenarios compared to actuals, 2013-14 to 2030-31



Source: AEMO.

DER are expected to have a significant effect on the peak demand forecast across the outlook period (see Section 4.2 for further details on DER forecasts and assumptions). In summary:

- **Behind-the-meter PV** – in the expected demand growth scenario, the peak demand reduction from behind-the-meter PV is expected to remain roughly constant over the outlook period, despite the installed capacity of behind-the-meter PV being forecast to almost double. In 2020-21, the behind-the-meter PV capacity factor⁹⁵ at the time of peak demand is estimated to be 8% and is forecast to decline to 4% by 2030-31. In the high demand growth scenario, peak reduction from behind-the-meter PV is forecast to decline as peak demand shifts closer to sunset when solar irradiance is minimal.

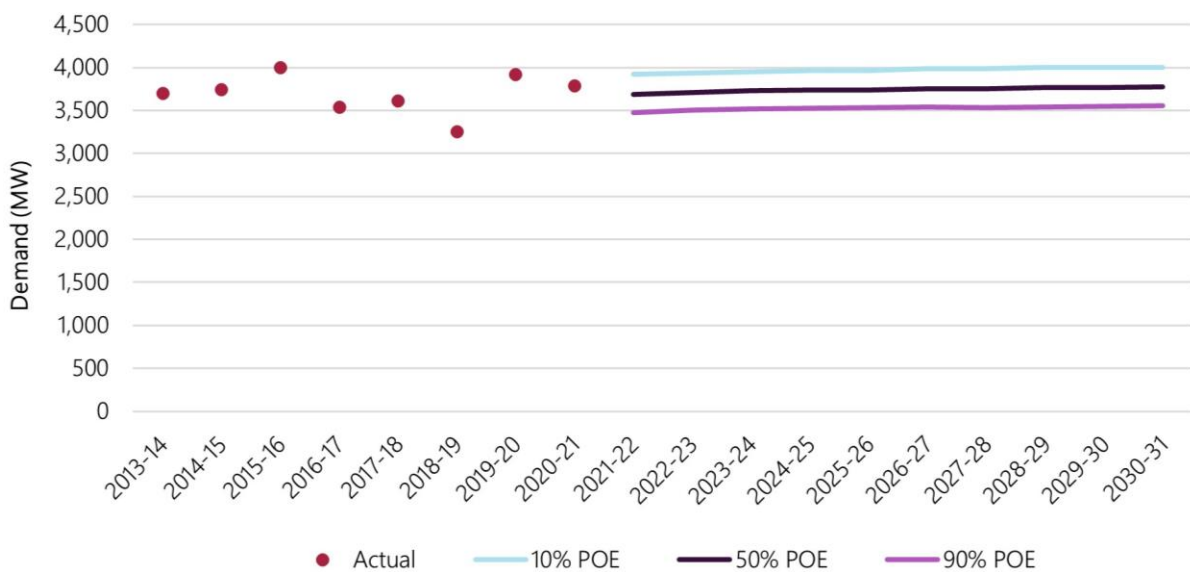
⁹⁴ Business sector refers to small to medium enterprises combined with LILs.

⁹⁵ Capacity factor refers to the ratio between installed behind-the-meter generation and total installed capacity.

- **Battery storage** – in all demand growth scenarios, battery storage is forecast to reduce peak demand, by discharging after sunset (for customers on flat tariffs) or due to high price signals (for customers on time-of-use tariffs).
- **EVs** – of the four modelled profiles (convenience, night, day, and fast/highway)⁹⁶, residential convenience charging is forecast to be the greatest contributor to peak demand. EV charging has a greater impact on peak demand towards the end of the outlook period due to increasing market penetration.

Figure 33 shows actual peak demand for the period 2013-14 to 2020-21 and the 10%, 50%, and 90% POE peak demand forecasts for the outlook period 2021-22 to 2030-31 under the expected demand growth scenario. All three forecasts show similar stable growth across the outlook period, with an average annual growth rate between 0.2% and 0.3%.

Figure 33 10%, 50%, and 90% POE peak demand forecasts under the expected demand growth scenario compared to actuals, 2013-14 to 2030-31



Source: AEMO.

Winter peak demand forecasts⁹⁷

Winter peak demand is expected to remain lower than summer peak demand throughout the outlook period. This is consistent with historical observations in the SWIS, where annual peak demand days are associated with hot weather and elevated loads associated with cooling.

In summary, for the 10% POE forecasts (see Appendix B4 for the full set of winter peak demand forecasts):

- In the **low demand growth scenario**, winter peak demand is projected to decline across the outlook period at an average annual rate of 1.1%, as a result of battery storage discharging, despite increasing demand from LILs and EV charging.
- In the **expected demand growth scenario**, winter peak demand is projected to increase at an average annual rate of 0.1% over the outlook period, as a result of increased EV charging and growth in LILs which is not fully offset by reduced load from battery storage discharging.
- In the **high demand growth scenario**, winter peak demand is projected to increase at an average annual growth rate of 2.0%, largely as a result of higher forecasts for EV charging and for residential and business sector demand compared to the expected and low demand growth scenarios.

⁹⁶ EV charging profiles are discussed in more detail in Section 4.2.3.

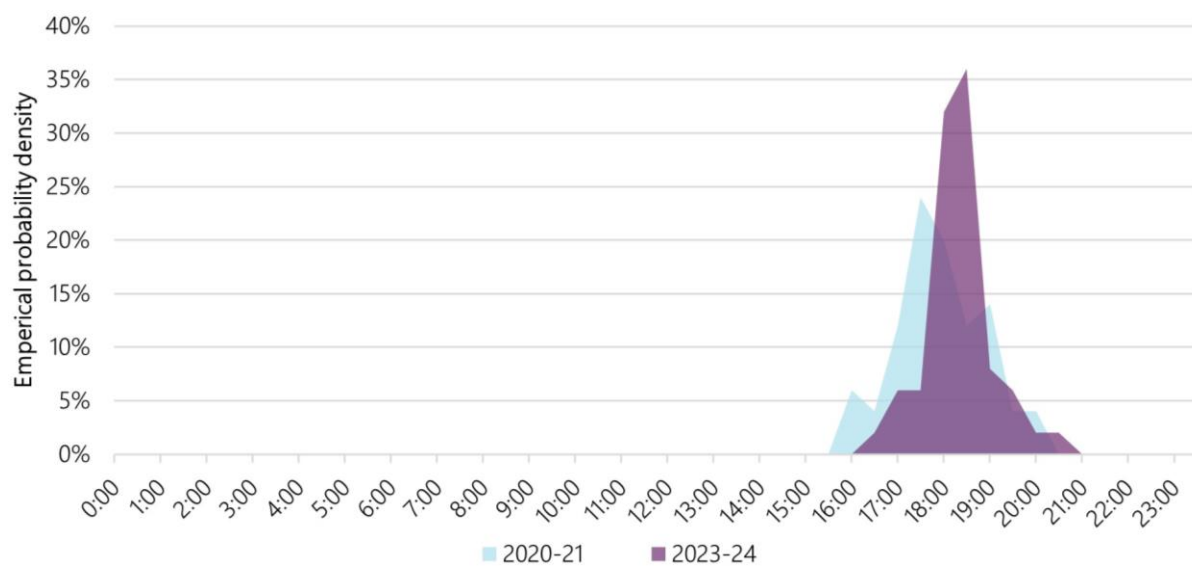
⁹⁷ The seasons are split into summer (Trading Months December – March), winter (Trading Months June – August), and the shoulder season, which includes all other months.

Timing of peak demand

AEMO 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 the timing of peak demand (see Section 3.1.2). For the 2021 WEM ESOO, AEMO ran 5,000 simulations of half-hourly demand for each scenario and year in the outlook period. Increasing the number of simulations (from 1,000 simulations in the 2020 WEM ESOO) provides a greater level of certainty around the expected timing and distribution of peak demand.

In the 10% POE expected demand growth scenario, peak demand is forecast to continue to occur during summer and is expected to shift 30 minutes later, from the period between 17:30 and 18:30⁹⁸ to between 18:00 and 19:00 by 2023-24 (see Figure 34). This is due to the combined impacts of behind-the-meter PV generation and battery storage operation, and, to a lesser extent, convenience charging⁹⁹ of EVs.

Figure 34 Distribution of forecast time of 10% POE peak demand, expected demand growth scenario



Source: AEMO.

5.1.2 Changes from previous forecasts

The peak demand forecasts presented in the 2021 WEM ESOO are lower than the forecasts in the 2020 WEM ESOO in the first two years of the outlook period and are then higher for the remainder of the outlook period (see Table 11).

Key drivers for the differences include:

- Higher residential demand forecasts across the outlook period due to stronger growth in the number of residential connections (see Appendix A1).
- A reduction in the business demand forecast at the start of the outlook period to better align with historical actuals. This is offset later in the outlook period with forecast moderate growth due to reduced downside risk from the COVID-19 pandemic in the 2021 WEM ESOO.
- An increased number of simulations for the 2021 WEM ESOO providing more certainty around the distribution of forecast peak demand and less year-on-year variability.

⁹⁸ The simulated distribution of peak demand times for 2020-21 closely matches observed recent annual peak demand days. Since 2015-16, all annual peak demand days have occurred during the 17:00 to 17:30 and 18:00 to 18:30 Trading Intervals.

⁹⁹ 'Convenience charging' refers to charging of EVs that are assumed to have no incentive to charge at specific times.

Table 11 Difference between 10% POE expected scenario forecasts, 2020 WEM ESOO and 2021 WEM ESOO (MW)

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
2020 WEM ESOO forecast	4,018	4,002	3,913	3,923	3,964	3,942	3,959	3,908	3,937
2021 WEM ESOO forecast	3,917	3,937	3,953	3,966	3,967	3,984	3,989	3,998	4,001
Difference	-101	-65	40	43	3	42	30	90	64

5.1.3 Peak demand forecast accuracy

Peak demand for 2020-21 was 3,789 MW, observed on 8 January 2021 during the 18:00 to 18:30 Trading Interval (see Section 3.1.2 for more details). The peak demand event was 15 MW higher than the 50% POE expected demand growth scenario forecast in the 2020 WEM ESOO, and would be within the range of a 40% to 50% POE event. The conditions observed on the 2020-21 peak demand day suggest that the 2020 WEM ESOO one-year-ahead annual peak forecast performed well.

The following factors contributed to the 15 MW variance:

- **Weather effects** – maximum temperature¹⁰⁰ on the day (41.7°C) was toward the higher end of the forecast distribution for daily maximum temperature (38°C-42°C).
- **Timing of peak demand** – peak demand occurred during the 18:00 to 18:30 Trading Interval, at the later end of the forecast distribution for peak demand timing (between the Trading Interval commencing 16:30 to the Trading Interval commencing 18:00 on a weekday).
- **Behind-the-meter PV** – rooftop PV generation¹⁰¹ (79 MW) was estimated to be toward the lower end of the forecast distribution for a peak demand event (74 MW to 136 MW). This was due to operational peak demand occurring at the later end of the forecast distribution for peak demand timing when solar irradiance is lower.

5.2 Minimum demand forecasts

Market and operational interventions are required to ensure the system stays secure and stable during minimum demand events, and AEMO is actively addressing these issues through the WA DER Roadmap in conjunction with Energy Policy WA and Western Power (see Chapter 7 for more information).

Minimum demand forecasts are presented in the 2021 WEM ESOO for a five-year outlook period. In all demand growth scenarios, decreasing minimum demand is primarily driven by projected growth in behind-the-meter PV installations. In the expected demand growth scenario, installed behind-the-meter PV capacity is forecast to increase from 2,197 MW to 3,115 MW between 2021-22 and 2025-26.

All annual minimum demand events 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).

¹⁰⁰ In the 2021 WEM ESOO, the peak demand forecast model has been based on the Perth Metro weather station (station identification number 9225). All historical temperature references in this WEM ESOO relate to the Perth Airport weather station (station identification number 9021).

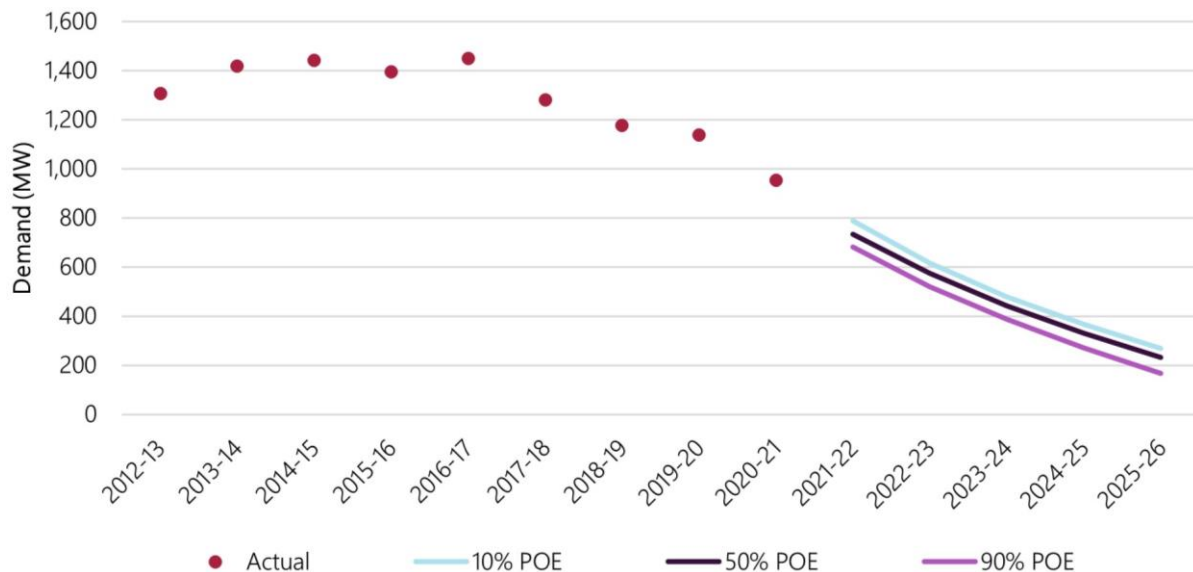
¹⁰¹ Rooftop PV refers to behind-the-meter PV generation excluding PVNSG. Behind-the-meter PVNSG generation was estimated to be 2 MW during this Trading Interval.

5.2.1 Annual minimum demand forecasts

The minimum demand forecast is presented below for the expected demand growth scenario for 10%, 50%, and 90% POE. The key driver for rapidly declining minimum demand is the continued strong uptake of behind-the-meter PV, partially offset by growth in business and residential loads.

The minimum demand forecast in the 2021 WEM ESOO is lower than that forecast in the 2020 WEM ESOO across the five-year outlook period, which is driven by a higher forecast for behind-the-meter PV uptake.

Figure 35 10%, 50%, and 90% POE forecast minimum demand under the expected demand growth scenario compared to actuals^A, 2013-14 to 2025-26



A. Actual minimum demand for the 2020-21 Capacity Year is a year-to-date value, based on data until 31 March 2021.
Source: AEMO.

Timing of minimum demand

Operational minimum demand events continue to occur through the shoulder season and are strongly influenced by behind-the-meter PV generation. While Figure 35 shows minimum demand forecasts by Capacity Year, given the progressive uptake of behind-the-meter throughout the year, minimum demand events are most likely to occur in the shoulder period towards the end of the Capacity Year.

Minimum demand in the expected demand growth scenario is forecast to occur between the Trading Interval commencing 10:30 through to the Trading Interval commencing 13:30 across the outlook period. This period is broadly consistent with historical trends and aligns with solar noon¹⁰² when behind-the-meter PV generation is at its peak (on a clear-sky day). Since the 2020 WEM ESOO was published there have been six new minimum demand records set, all occurring between the Trading Interval commencing 11:30 and Trading Interval commencing 13:00 (see Section 3.2.3).

5.3 Consumption forecasts

Figure 36 compares the operational consumption forecasts for the 2020 and 2021 WEM ESOOs for the low, expected, and high demand growth scenarios. An increased forecast for behind-the-meter PV uptake¹⁰³ in the 2021 WEM ESOO is the primary driver for lower consumption forecasts for all three demand growth scenarios. There was also a small decrease in the EV consumption forecast in the 2021 WEM ESOO, due to revised consumption estimates from CSIRO that incorporate losses and changes in vehicle efficiency. These

¹⁰² Solar noon time is dependent on longitude and date and occurs when the sun is at its highest point in the sky. Solar noon for Perth varies across the year between 12:00 to 12:30, as calculated at <https://gml.noaa.gov/grad/solcalc/>.

¹⁰³ More than 35% increase in behind-the-meter generation by 2030-31 for the expected demand growth scenario.

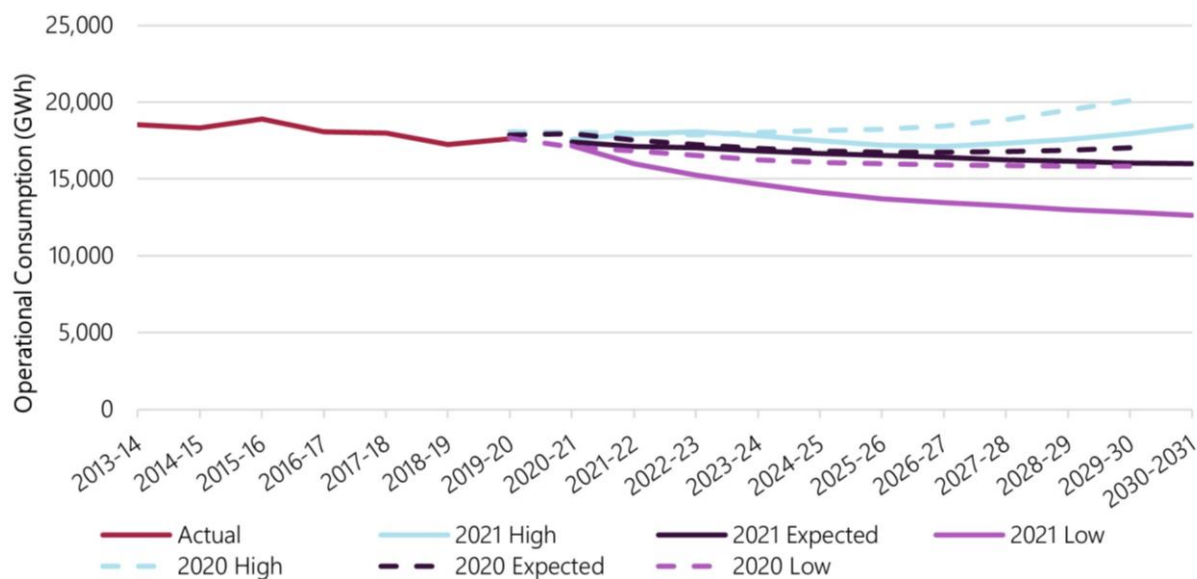
factors were partially offset by moderate discounting applied to the energy efficiency savings¹⁰⁴ for the low and expected demand growth scenarios, which served to increase consumption forecasts. Additionally, downside risk from the COVID-19 pandemic was reduced in the 2021 WEM ESOO, which provided some uplift in consumption.

In summary, over the outlook period:

- In the **low demand growth scenario**, operational consumption is forecast to decline at an average annual rate of 2.6% as a result of a greater proportion of residential and business customer consumption being met by behind-the-meter PV, energy efficiency improvements, and a weaker pace of investment growth (see Appendix A1).
- In the **expected demand growth scenario**, operational consumption is forecast to decline at an average annual rate of 0.8%. In this scenario, increased behind-the-meter PV consumption and energy efficiency improvements are partially offset by energy use by EVs and growth in LIL consumption (1.7% on average) over the outlook period.
- In the **high demand growth scenario**, operational consumption is forecast to grow at an average annual rate of 0.3%. Over the first half of the outlook period, operational consumption is forecast to decline at an average annual rate of 1.1% due to the high rate of behind-the-meter PV uptake. This is offset in the second half of the outlook period by strong uptake of EVs and steady growth from LILs.

A full set of operational consumption forecasts is provided in Appendix B6.

Figure 36 Operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31



Source: AEMO.

5.3.1 Residential sector forecasts

Figure 37 shows residential operational consumption actuals and forecasts under the low, expected, and high scenarios compared with forecasts from the 2020 WEM ESOO.

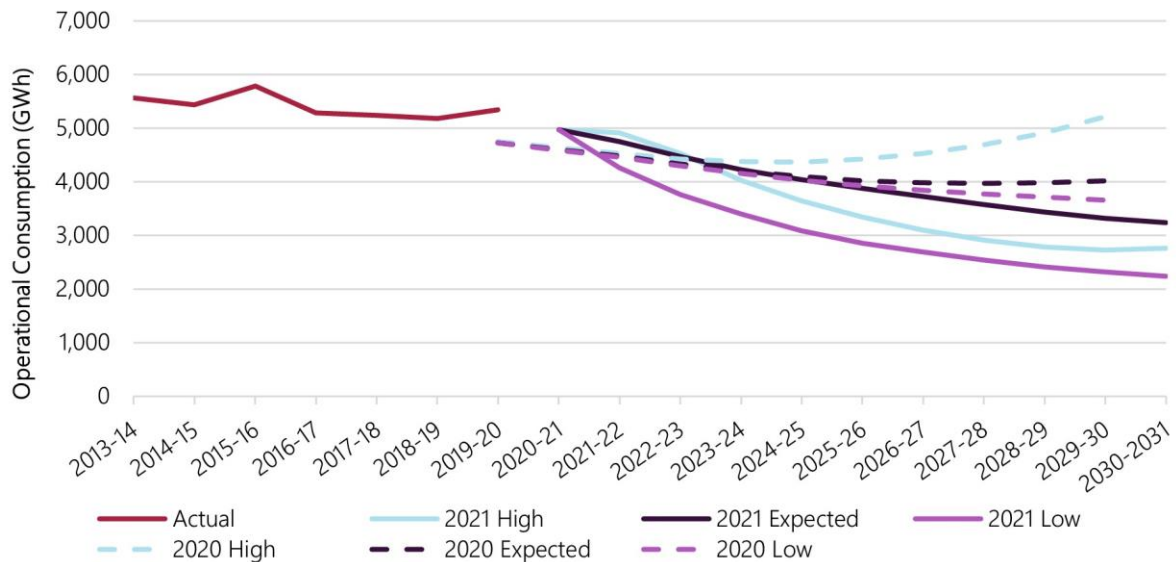
Residential operational consumption is forecast to decline over the outlook period in all three growth scenarios, largely attributed to the continued uptake of behind the-meter PV, at an average annual rate of:

- 6.9% in the low demand growth scenario.

¹⁰⁴ AEMO commissioned Strategy. Policy. Research. Pty Ltd (SPR) to provide energy efficiency forecasts for the 2021 WEM ESOO. SPR revisited policy-based assumptions from its forecasts (previously developed in 2019) with the latest developments in policy roll-out and market-led technological adoption.

- 4.2% in the expected demand growth scenario.
- 6.2% in the high demand growth scenario.

Figure 37 Residential operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31



Source: AEMO.

In the 2021 WEM ESOO, the high growth scenario falls below the expected growth scenario from 2023-24 onwards, due to the higher behind-the-meter PV forecast in the high scenario relative to the expected scenario. This did not occur in the 2020 WEM ESOO because the expected scenario behind-the-meter PV forecast was applied to all three growth scenarios.

Compared to the 2020 WEM ESOO, consumption forecasts are lower across all three scenarios, primarily driven by higher behind-the-meter PV forecasts for the residential sector in the 2021 WEM ESOO.

Underlying residential consumption in the expected demand growth scenario is forecast to continue to grow steadily over the next 10 years, from 6,922 GWh in 2021-22 to 7,527 GWh¹⁰⁵ in 2030-31. While ongoing improvements in energy efficiency are forecast to offset some growth in underlying residential consumption, net growth is positive and largely driven by increases in residential connections and EV uptake.

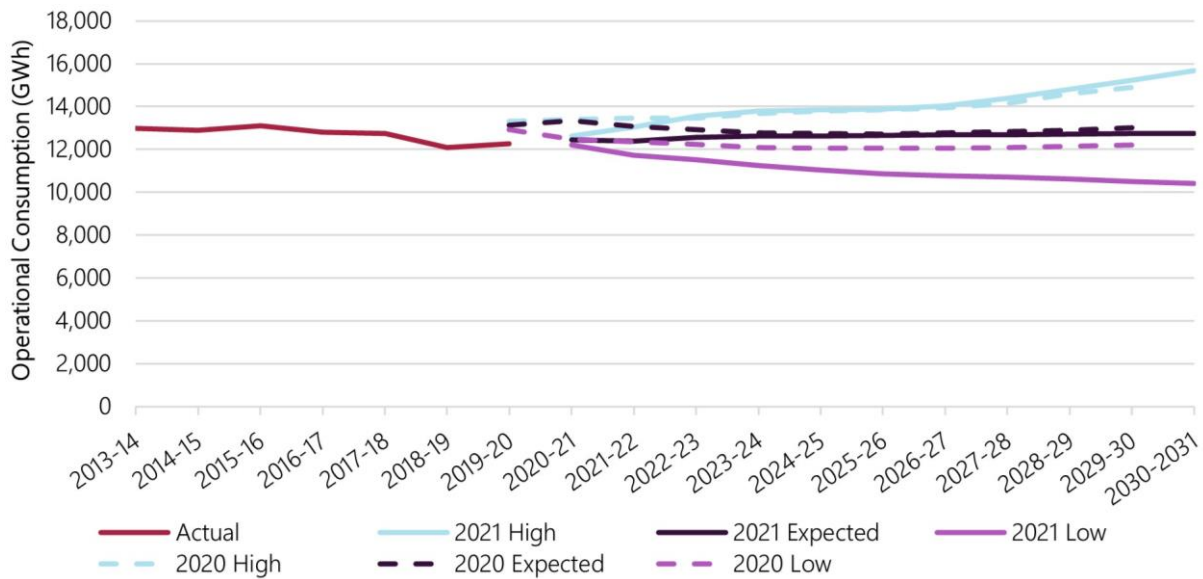
5.3.2 Business sector forecasts

Figure 38 shows business operational consumption forecasts under the expected, low, and high demand growth scenarios. In summary:

- In the **low demand growth scenario**, business operational consumption is forecast to decline at an average annual rate of 1.3%.
- In the **expected demand growth scenario**, business operational consumption is forecast to grow at an average annual rate of 0.3%, largely driven by EV (78.1% a year on average) and LIL consumption (1.5% a year on average), which is partly offset by efficiency improvements and growth in behind-the-meter PV (11.2% a year on average).
- In the **high demand growth scenario**, business operational consumption is forecast to grow at an average annual rate of 2.1% as a result of growth in LILs including prospective loads, combined with higher EV consumption.

¹⁰⁵ Residential underlying consumption excluding consumption associated with EVs.

Figure 38 Business operational consumption forecasts under three demand growth scenarios from the 2020 and 2021 WEM ESOOs compared to actuals, 2013-14 to 2030-31



Source: AEMO.

Compared to the 2020 WEM ESOO:

- For the low demand growth scenario, business sector consumption is lower due to reduced forecasts for small and medium business customers.
- For the expected demand growth scenario, a reduction in forecast consumption for small and medium business customers was partially offset by increased loads from LILs.
- For the high demand growth scenario, increased consumption forecasts were driven by an increase in LIL consumption from new mining and mineral processing plant projects.

6. Reliability assessment outcomes

This chapter reports the Reserve Capacity Target (RCT) determined for each Capacity Year of the 2021 Long Term Projected Assessment of System Adequacy (PASA) Study Horizon (2021-22 to 2030-31 Capacity Years). The RCT determined for the 2023-24 Capacity Year sets the RCR for the 2021 Reserve Capacity Cycle. The RCR for the 2021 Reserve Capacity Cycle is 4,396 MW, and no capacity shortfall is anticipated across the 2021 Long Term PASA Study Horizon.

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 capacity that will only be required during peak periods¹⁰⁶.

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 Rules¹⁰⁷. AEMO uses the Planning Criterion to set the 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 forecast¹⁰⁸ under the expected demand growth scenario plus allowances for Intermittent Loads¹⁰⁹, frequency control¹¹⁰, and a reserve margin¹¹¹ ("defined scenario"¹¹²).

¹⁰⁶ 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 the value that 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. Generally, a more conservative reliability standard has higher costs for consumers.

¹⁰⁷ The 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. From 1 July 2021, responsibility for the review of the Planning Criterion will be transferred from the ERA to the Coordinator of Energy, see <https://www.erawa.com.au/cproot/21698/2/Wholesale-Electricity-Market-Amendment-Governance-Rules-2021.pdf>.

¹⁰⁸ See Section 5.1 for more information on the 10% POE peak demand forecast.

¹⁰⁹ An Intermittent Load is normally fully served by embedded generation and only requires electricity from the network when its embedded generator is not operating. 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.

¹¹⁰ Additional capacity required to provide Minimum Frequency Keeping Capacity and ensure that Load Following Ancillary Services (LFAS) are maintained.

¹¹¹ The reserve margin accounts for both the annual variability of peak demand in the SWIS and the failure of the largest generating unit.

¹¹² For detailed information on the defined scenario, see Section 6.2 of the 2020 WEM ES00, at https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2020/2020-wholesale-electricity-market-electricity-statement-of-opportunities.pdf.

- Limit expected unserved energy (EUE)¹¹³ to 0.002% of annual forecast expected energy consumption¹¹⁴.

Since the RCM commenced in 2005, the defined scenario has set the RCTs, because it has exceeded the capacity required to satisfy the EUE component of the Planning Criterion.

AEMO engaged Robinson Bowmaker Paul (RBP) to conduct the reliability assessment, including the EUE assessment, determination of the Availability Classes capacity requirements and Availability Curves¹¹⁵. A summary of the assessment methodology and changes to the methodology relative to the 2020 WEM ESOO are presented in Appendix A.3. Further information about the methodology can be found in RBP's report¹¹⁶.

6.2 The Reserve Capacity Target

6.2.1 Defined scenario

Table 12 shows the RCT, set by the expected 10% POE peak demand requirement of the Planning Criterion (defined scenario), for each Capacity Year of the 2021 Long Term PASA Study Horizon.

Table 12 Reserve Capacity Targets (MW)^A

Capacity Year	10% POE peak demand	Intermittent Loads ^B	Reserve margin ^C	Load following ^D	Total
2021-22 ^E	3,917	3	331	105	4,356
2022-23 ^E	3,937	3	335	105	4,380
2023-24	3,953	3	335	105	4,396
2024-25	3,966	3	335	105	4,409
2025-26	3,967	3	335	105	4,410
2026-27	3,984	3	335	105	4,427
2027-28	3,989	3	335	105	4,432
2028-29	3,998	3	335	105	4,441
2029-30	4,001	3	335	105	4,444
2030-31	4,000	3	335	105	4,443

A. All figures have been rounded to the nearest MW.

B. Estimate of the capacity allowance required to cover the forecast cumulative needs of Intermittent Loads, which are excluded from the 10% POE expected peak demand forecast; estimated in accordance with clause 4.5.2A of the WEM Rules using an iterative process to adjust the forecast maximum possible Intermittent Load levels by the ratio of the RCT to the 10% POE expected peak demand forecast.

C. Calculated as the greater of 7.6% of the sum of the 10% POE forecast peak demand plus the Intermittent Load allowance and the maximum sent out capacity (measured at 41°C) of the largest generating unit. To set the RCT, 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 for the 2021-22 Capacity Year. NewGen Kwinana (334.8 MW, calculated on a sent out basis at 41°C) becomes the largest generating unit from the 2022-23 Capacity Year onward.

D. Since the 2020 WEM ESOO, the ERA has approved the LFAS requirements for the 2020-21 financial year as 105 MW between 05:30-19:30 and 80 MW between 19:30-05:30 (see <https://www.erawa.com.au/cproot/21449/2/ERA-letter-to-AEMO---Approval-of-revised-2020-21-LFAS-requirements.PDF>). AEMO considers the load following requirement of 105 MW in calculating the RCTs to cover peak demand periods and assumes no change to this requirement over the outlook period. From October 2022, this requirement may change with the implementation of a five-minute Dispatch Interval and the new Essential System Services framework as part of the introduction of security constrained economic dispatch constraints in the WEM.

E. Figures have been updated to reflect the current forecasts. However, the RCR of 4,482 MW set in in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle and the RCR of 4,421 MW set in the 2020 WEM ESOO for the 2020 Reserve Capacity Cycle do not change.

¹¹³ A normalised metric, which does not have a unit.

¹¹⁴ The energy consumption forecast is based on TSOG data. See Section 5.3 for further information.

¹¹⁵ Required under clauses 4.5.12 and 4.5.10(e) of the WEM Rules.

¹¹⁶ RBP 2021. 2021 assessment of system reliability for the South West interconnected system, at <https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

The RCT determined for the 2023-24 Capacity Year is 4,396 MW, which sets the RCR for the 2021 Reserve Capacity Cycle. This is:

- Lower than the RCR for the 2020 Reserve Capacity Cycle in relation to the 2022-23 Capacity Year (4,421 MW) set in the 2020 WEM ESOO, as a result of a lower 10% POE forecast peak demand, partially offset by increased requirements for the reserve margin and load following requirements.
- Higher than the RCT for the 2023-24 Capacity Year (4,332 MW) that was forecast in the 2020 WEM ESOO, due to marginally higher 10% POE peak demand forecasts¹¹⁷ and an increase in the reserve margin and load following requirements.

6.2.2 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 2021 Long Term PASA Study Horizon. In summary, the assessment found EUE is likely to occur both in summer when demand is generally higher, and in winter when more planned outages are scheduled and less intermittent generation is available. Compared to the 2020 WEM ESOO assessment, EUE has increased in each Capacity Year in this assessment, particularly in the 2029-30 Capacity Year. This is largely driven by:

- The implementation of full constrained network access from October 2022¹¹⁸. Generators that are in congested areas of the network, including new generators, increase the risk of unserved energy (or the magnitude of unserved energy if it already exists) when their generation is reduced by constraints.
- An increase in planned outages reported by Rule Participants in response to the information request under clause 4.5.4 of the WEM Rules compared with the 2020 WEM ESOO, particularly in the 2029-30 Capacity Year.
- The implementation of five historical reference years for load forecasting¹¹⁹. In particular, the forecast load profiles based on the 2016-17 and 2018-19 reference years had high winter demand¹²⁰, which has driven the majority of EUE.
- There is forecast to be a higher risk of unserved energy occurring between 17:00 and 20:00¹²¹ because of increasing behind-the-meter PV penetration shifting peak demand Trading Intervals to evening periods when capacity margins become low due to high demand.

The results of the EUE assessment are provided in Appendix B2. See RBP's report for more details¹¹⁶.

6.3 Availability Classes

CRC is allocated to two classes based on capacity availability:

- Availability Class 1 relates to generation capacity and any other capacity¹²² that is expected to be available for dispatch for all Trading Intervals, allowing for outages or other restrictions.

¹¹⁷ The 10% POE peak demand that was forecast for the 2023-24 Capacity Year was 3,913 MW in the 2020 WEM ESOO.

¹¹⁸ This framework is being developed to improve generator access to the Western Power network and is expected to go live in October 2022.

¹¹⁹ In the 2020 WEM ESOO, an average underlying load shape was applied to the 2018-19 Capacity Year's chronology to produce the underlying reference load profile. In the 2021 WEM ESOO, the underlying load shape and chronology of each of the five historical years (the 2015-16 to 2019-20 Capacity Years) was applied to the forecast underlying load profiles for each of Capacity Year in the outlook period. See Appendix A3.1 for further information.

¹²⁰ The 2016-17 and 2018-19 Capacity Years had a mild summer peak demand, but a high winter peak demand (see the 2020 WEM ESOO Section 3.1.3 for more).

¹²¹ This is largely in line with the result presented in the 2020 WEM ESOO. See Section 7.1.2 of the 2020 WEM ESOO for further information.

¹²² Hybrid Facilities that include both generation and ESR capacity are considered to be in Availability Class 1. Amendments to the WEM Rules were gazetted in December 2020 to provide for the participation of ESR capacity under the RCM. See <https://www.erawa.com.au/cproot/21670/2/Wholesale-Electricity-Market-Amendment-Tranches-2-and-3-Amendments-Rules-2020.pdf>.

- Availability Class 2 relates to capacity¹²³ that is not expected to be available for dispatch for all Trading Intervals¹²⁴.

The minimum Availability Class 1 capacity requirement and the capacity associated with Availability Class 2 for the 2022-23 and 2023-24 Capacity Years are shown in Table 13. For the 2021 Reserve Capacity Cycle, the Availability Class 1 capacity requirement outlined in Table 13 for the 2023-24 Capacity Year sets the minimum amount of generation capacity that is required to be procured in the RCM to avoid a generation capacity shortfall. The Availability Class 1 capacity can be used to fulfil the capacity requirement associated with Availability Class 2 to meet the RCR.

Table 13 Availability Classes (MW)

	2022-23 ^A	2023-24 ^B
Minimum capacity required to be provided from Availability Class 1	3,730	3,496
Capacity associated with Availability Class 2	650 ^C	900 ^D
RCT	4,380	4,396

A. These figures reflect the current forecasts. The RCT of 4,421 MW, as determined in the 2020 WEM ESOO for the 2022-23 Capacity Year and which set the RCR for the 2020 Reserve Capacity Cycle, remains unchanged. This comprised capacity requirements of 3,371 MW of Availability Class 1 and 1,050 MW of Availability Class 2 which also remain unchanged.

B. The RCT of 4,396 MW for the 2023-24 Capacity Year is the RCR for the 2021 Reserve Capacity Cycle.

C. Comprises solely DSM capacity, as no stand-alone ESR capacity holds Capacity Credits for the 2022-23 Capacity Year.

D. Included both DSM and stand-alone ESR capacity.

Source: AEMO and RBP.

For the 2022-23 Capacity Year, the minimum capacity required to be provided by Availability Class 1 has increased by 359 MW and the capacity associated with Availability Class 2 has decreased by 400 MW, from the values published in the 2020 WEM ESOO. This is largely driven by a lower capacity margin as a result of more scheduled Planned Outages in the shoulder season, and DSM capacity being typically unavailable for dispatch because its full 200 hours of availability had been exhausted. This leads to a higher Availability Class 1 capacity requirement to limit EUE to 0.002% of annual forecast expected energy consumption.

For the 2023-24 Capacity Year, the maximum Availability Class 2 capacity increases from 650 MW in the 2022-23 Capacity Year to 900 MW, primarily driven by including stand-alone ESR together with DSM capacity as Availability Class 2 capacity in the 2021 Availability Classes modelling. This has increased the amount of Availability Class 2 capacity that is available to mitigate unserved energy during peak demand periods in shoulder seasons¹²⁵. This has reduced the amount of Availability Class 1 capacity required to limit EUE to 0.002% of annual forecast expected energy consumption.

6.4 Availability Curves

The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year¹²⁶. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads and LFAS.

¹²³ Includes DSM and stand-alone ESR capacity.

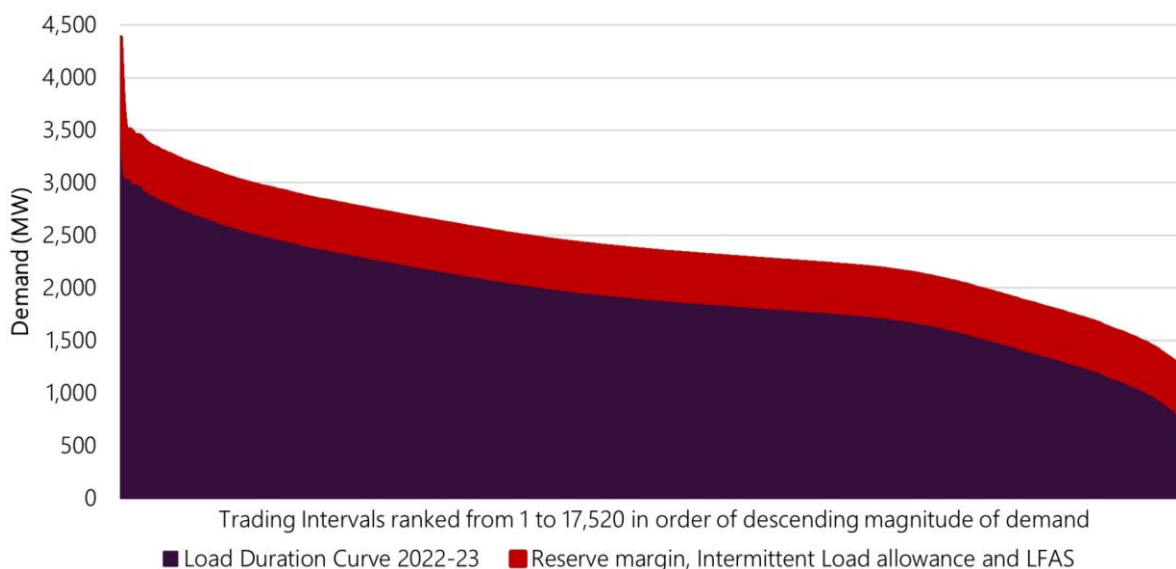
¹²⁴ DSM capacity is required to satisfy the minimum availability requirements as specified in clause 4.10.1(f) of the WEM Rules, including being available to provide capacity for at least 200 hours in a Capacity Year to participate in the RCM. ESR capacity is required to be available for the Electric Storage Resource Obligation Intervals.

¹²⁵ Stand-alone ESR capacity was assumed to be available between 16:00 and 20:00 each Trading Day, as these times generally coincide with peak operational demand.

¹²⁶ 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 plus an amount of available capacity margin.

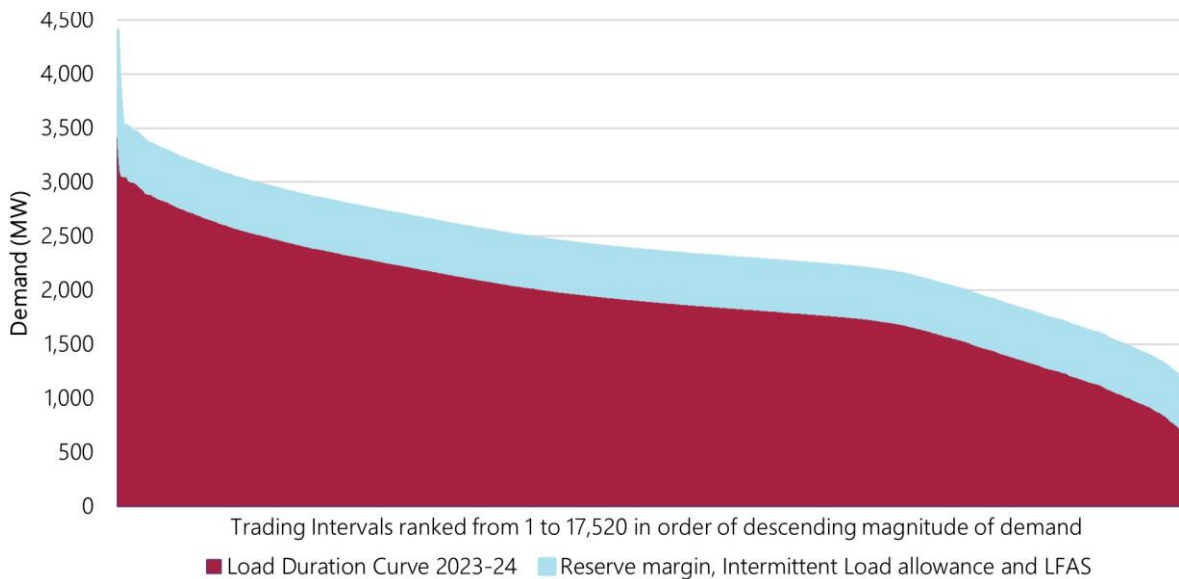
The Availability Curves for the 2022-23 and 2023-24 Capacity Years are shown in Figure 39 and Figure 40¹²⁷.

Figure 39 2022-23 Capacity Year Availability Curve



Source: RBP.

Figure 40 2023-24 Capacity Year Availability Curve



Source: RBP.

6.5 Opportunity for investment

6.5.1 Supply-demand balance

To forecast the capacity supply-demand balance over the 2021 Long Term PASA Study Horizon, AEMO has assumed that:

- There are no scheduled capacity retirements other than Muja C unit 5 and Muja C unit 6¹²⁸.

¹²⁷ Under the current methodology, the forecast minimum capacity requirement for the initial 24 hours uses the 10% POE peak demand forecast, assuming the expected demand growth scenario. After this period, the forecast minimum capacity requirements are expected to match the load profile with a 50% POE peak demand forecast, under the expected demand growth scenario.

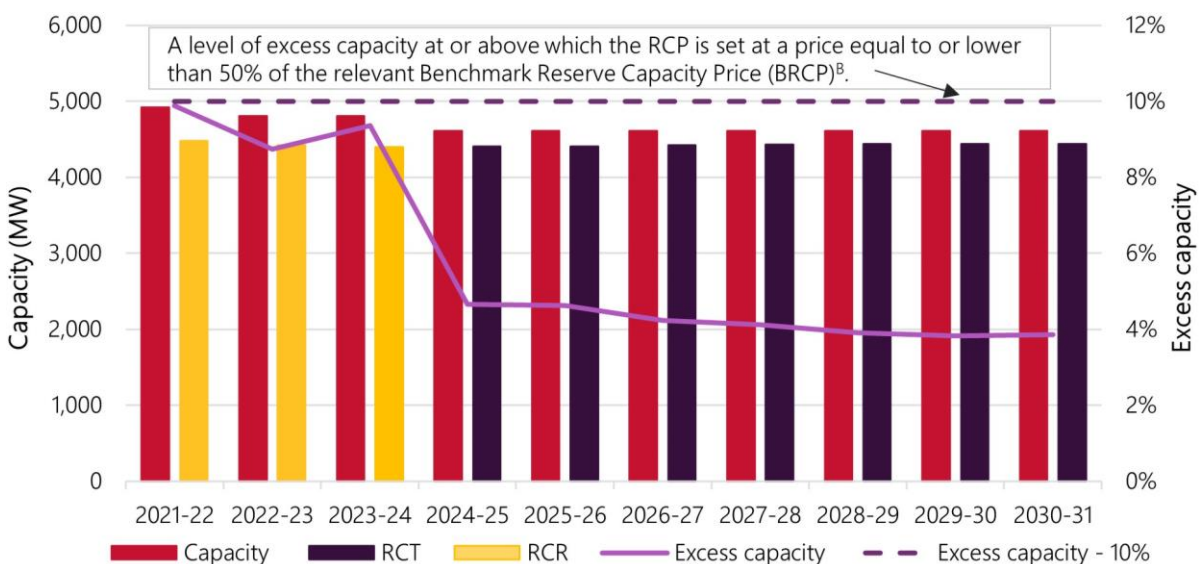
¹²⁸ Muja C unit 5 and Muja C unit 6 are scheduled to retire in the 2022-23 and 2024-25 Capacity Years respectively.

- No new committed capacity¹²⁹ commences operation over the Long Term PASA Study Horizon, except new Facilities¹³⁰ that were assigned Capacity Credits for the 2021-22 and 2022-23 Capacity Years.
- No probable projects¹³¹ are developed over the Long Term PASA Study Horizon.
- The total amount of generation capacity assigned Capacity Credits is 4,840 MW for the 2021-22 Capacity Year, 4,721 MW for the 2022-23 and 2023-24 Capacity Years, and 4,528 MW for each Capacity Year in the remainder of the Long Term PASA Study Horizon¹³².
- The total number of Capacity Credits assigned to DSM capacity is 84.5 MW for the 2021-22 Capacity Year and 86 MW for the remainder of the Long Term PASA Study Horizon.

In Figure 41, 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 retirements of Muja C unit 5 and Muja C unit 6 respectively.

The forecast capacity supply-demand balance for the high and low demand growth scenarios can be found in Appendix B1.

Figure 41 Reserve Capacity supply-demand balance, 2021-22 to 2030-31^{A,B}



A. The 2021-22 and 2022-23 capacity values are actuals and the remaining years are forecasts.

B. The BRCP represents the marginal cost of providing one additional MW of Reserve Capacity in the relevant Capacity Year; see <https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/benchmark-reserve-capacity-price>.

Table 14 provides a more detailed capacity outlook for the 2021-22 to 2023-24 Capacity Years. Excess capacity decreases from 443 MW (9.9%) to 386 MW (8.7%) between the 2021-22 and 2022-23 Capacity Years as a result of the retirement of Muja C unit 5 (195 MW) in October 2022.

This is partially offset by a decrease in the RCR and the inclusion of one new waste-to-energy Facility (25.134 MW of Capacity Credits) and one upgrade to a generation Facility (0.719 MW of Capacity Credits). Excess

¹²⁹ Committed capacity for a Capacity Year refers to new Energy Producing System (generation or ESR) or DSM capacity that holds Capacity Credits for the relevant Capacity Year but has not held Capacity Credits for a previous Reserve Capacity Cycle. See paragraph 2.10.3 of the WEM Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion, at <https://www.aemo.com.au/-/media/files/electricity/wem/procedures/2017/undertaking-the-long-term-pasa-and-conducting-a-review-of-the-planning-criterion.pdf>.

¹³⁰ Phoenix Kwinana waste-to-energy holds Capacity Credits for both the 2021-22 and 2022-23 Capacity Years (33.000 MW). East Rockingham waste-to-energy (25.134 MW) and the AmbriSolar upgrade (0.719 MW) hold Capacity Credits for the 2022-23 Capacity Year.

¹³¹ Probable projects refer to Facilities that have not already received Capacity Credits for a previous Reserve Capacity Cycle but have been granted CRC for the current Reserve Capacity Cycle, as outlined in paragraph 2.10.4 of the WEM Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion.

¹³² The AmbriSolar upgrade is included as generation capacity from the 2022-23 Capacity Year.

capacity is expected to increase to around 411 MW (9.4%) in the 2023-24 Capacity Year, as a result of a lower RCR¹³³.

The 2021 reliability study considered the network constraints that apply to Constrained Access Facilities¹³⁴ for the 2021-22 Capacity Year and full constrained network access from 1 October 2022. No localised supply restrictions are expected to exist in the SWIS that affect the ability of capacity to satisfy the RCT in each Capacity Year over the Long Term PASA Study Horizon¹³⁵.

The level of capacity 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 7). Proponents, investors, and developers should make independent assessments of future possible supply and demand conditions.

Table 14 Capacity outlook in the SWIS, 2021-22 to 2023-24 Capacity Years (MW)^A

Capacity category	2021-22	2022-23	2023-24 ^B
Energy producing capacity^C	4,840	4,721	4,721
• Existing ^D	4,807 ^E	4,695 ^{E, F}	4,721 ^G
• Committed ^H	33 ^E	26 ^H	0
DSM capacity	85	86^I	86
• Existing ^D	85	86	86
• Committed ^H	0	0	0
Total capacity	4,925	4,807	4,807
RCR	4,482	4,421	4,396
Excess capacity	443 (9.9%)	386 (8.7%)	411 (9.4%)

A. All capacity values are in terms of Capacity Credits, rounded to the nearest integer. Values for the 2021-22 and 2022-23 Capacity Years are Capacity Credits assigned for the 2019 and 2020 Reserve Capacity Cycles, respectively.

B. All Facilities are assumed to receive the same quantity of Capacity Credits in the 2023-24 Capacity Year as in the 2022-23 Capacity Year.

C. The Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020 include amending rules with respect to Energy Producing Systems. An Energy Producing System is defined as: "Set of one or more electricity producing resources or devices such as generation systems or Electric Storage Resources". This definition currently has legal effect under the transitional rule specified in clause 1.36C.6 of the WEM Rules.

D. Refers to existing Energy Producing Systems or DSM which has held Capacity Credits for a previous Reserve Capacity Cycle.

E. Comprises solely generation capacity.

F. The reduction from the 2021-22 to 2022-23 Capacity Years is primarily due to Muja C unit 5's retirement.

G. Includes ESR capacity as an upgrade to an existing Facility.

H. Refers to new Energy Producing Systems or DSM that holds Capacity Credits for the relevant Capacity Year but has not held Capacity Credits for a previous Reserve Capacity Cycle.

I. The increase in existing DSM capacity between the 2021-22 and 2022-23 Capacity Years is due to an increase in the quantity of Capacity Credits assigned to Wesfarmers Kleenheat Gas's DSP (1.5 MW of Capacity Credits).

6.5.2 Expressions of Interest for new capacity in the RCM

Under clause 4.1.4 of the WEM Rules, AEMO is required to run an EOI process each year for the relevant Reserve Capacity Cycle.

¹³³ See Section 6.2.1 for further information.

¹³⁴ The Generator Interim Access 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.

¹³⁵ This expectation may change in the future due to changes in the capacity mix or network augmentations in the SWIS.

The EOI process for the 2021 Reserve Capacity Cycle will open on 1 July 2021 and close on 16 August 2021¹³⁶. From the 2021 Reserve Capacity Cycle onwards, the EOI process is mandatory for new Facilities intending to apply for CRC¹³⁷.

¹³⁶ See <https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-timetable>.

¹³⁷ See the commencement dates for specific clauses of the Amending Rules as published in the Government Gazette, at [https://www.slp.wa.gov.au/gazette/gazette.nsf/searchgazette/93C09CCF6FF851CD4825866B0008CB84/\\$file/Gg020.pdf](https://www.slp.wa.gov.au/gazette/gazette.nsf/searchgazette/93C09CCF6FF851CD4825866B0008CB84/$file/Gg020.pdf).

7. Market developments and challenges

Chapter 7 highlights some developments and challenges in the WEM that are relevant to the RCM:

- WEM reviews and rule changes.
- WA's Energy Transformation Strategy initiatives.
- Infrastructure developments in the SWIS.
- Maintaining power system security and reliability.
- Industry trends.

7.1 WEM reviews and rule changes

7.1.1 Economic Regulation Authority reviews

The ERA has historically undertaken reviews of methods underpinning various processes and calculations in the WEM Rules. Although some methodologies scheduled for review have been postponed as a result of WEM reform activities, the 2020 review of incentives to improve the availability of generators has been completed by the ERA¹³⁸.

From 1 July 2021, the responsibility for undertaking the remaining reviews of methods underpinning various processes and calculations in the WEM Rules will be transferred from the ERA to the Coordinator of Energy and will include:

- Planning Criterion and long-term demand forecasting.
- Outage planning criteria.
- Ancillary services review.

However, the review of the Benchmark Reserve Capacity Price and Energy Price Limits¹³⁹ will be completed by the ERA.

7.1.2 Rule Change Proposals

There are multiple Rule Change Proposals¹⁴⁰ currently under development that may affect the RCM, including¹⁴¹:

¹³⁸ 2020 Review of Incentives to Improve Availability of Generators Final Report can be downloaded at <https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/2020-review-of-incentives-to-improve-availability-of-generators>.

¹³⁹ ERA 2021, Methodology Reviews, at <https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews>.

¹⁴⁰ Administrative Improvements to the Outage Process (RC_2014_03) has been finalised with commencement set for 29 June 2021.

¹⁴¹ ERA, *WEM Rule Changes* (updated 20 May 2021), at <https://www.erawa.com.au/rule-change-panel/wem-rule-changes>.

- Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03)¹⁴².
- Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price (RC_2014_05).
- Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03).
- The Relevant Demand calculation (RC_2019_01).

Effective from 1 July 2021, the Rule Change Panel function will be transferred from the ERA to the Coordinator of Energy¹⁴³.

7.2 Energy Transformation Strategy

The ETS is a WA Government initiative delivered by the Energy Transformation Implementation Unit within Energy Policy WA (EPWA). The ETS aims to deliver secure, reliable, sustainable and affordable electricity to Western Australians¹⁴⁴ while addressing the technical requirements to support the high penetration of behind-the-meter PV, increasing the number of battery energy storage systems and large-scale renewable generators (wind and solar farms) in the SWIS.

The ETS includes three key workstreams:

- Foundation Regulatory Frameworks (also known as WEM Reform), which consists of:
 - Improving Access to the SWIS – incorporates changes to regulations and other instruments to implement constrained network access as well as necessary, consequential changes to the RCM.
 - Delivering the Future Power System – modernises the WEM to enhance power system security and enable new generators' access to the network.
- Whole of System Plan (WoSP).
- WA DER Roadmap.

The Energy Transformation Implementation Unit concluded in May 2021 after a two-year tenure, with the remaining ETS activities to be led by EPWA¹⁴⁵.

7.2.1 WEM Reform updates

Amendments to the WEM Rules and the *Electricity Networks Access Code 2004* were made to reflect the ETS. 'Tranche 1' and 'Tranches 2 and 3' of the amending WEM Rules were gazetted on 24 November 2020 and 24 December 2020 respectively.

Key changes to the WEM include:

- The introduction of a market for Essential System Services (ESS).
- Security constrained economic dispatch co-optimised across energy and ESS.
- Five-minute dispatch intervals.
- A new framework for market settlement.
- Facility bidding by Synergy.

¹⁴² The Rule Change Panel is currently progressing RC_2019_03: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators. This Rule Change Proposal, if commenced, will change the Relevant Level Methodology used to assign Certified Reserve Capacity to Intermittent Generators. The Rule Change Proposal is expected to provide a better assessment of the capacity contribution of the fleet of Intermittent Generators and individual Intermittent Generators to system reliability and provide a transparent method that can be used by Market Participants to support their investment planning. For more information, see <https://www.erawa.com.au/rule-change-panel>.

¹⁴³ The Coordinator of Energy is supported by Energy Policy WA and will assist the Minister for Energy in planning and co-ordinating the delivery of energy across WA. See <https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/01/Changes-to-Western-Australias-energy-sector-governance.aspx>.

¹⁴⁴ Energy Transformation Strategy website, at <https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy>.

¹⁴⁵ Government of WA 2021, Media Statement (21 May 2021), "Energy Transformation Taskforce successfully concludes", at <https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/05/Energy-Transformation-Taskforce-successfully-concludes.aspx>.

- Improvements to power system operational planning, forecasting and outage management.
- A new framework introducing priority access for Facilities participating in the RCM.
- A new framework to enable the participation of ESR¹⁴⁶ in the RCM.
- Improved arrangements for generator performance monitoring and compliance.
- A new governance framework for WEM Rule changes, development of future WoSPs, and market development.

Full details of the changes to the WEM Rules can be accessed on the ERA website¹⁴⁷.

7.2.2 WEM Reform changes to the RCM

The ETS has implemented wide-ranging reforms in the RCM to support the adoption of a constrained network access model and the participation of ESR¹⁴⁸. The WEM Reform RCM changes will be implemented in a phased approach across both the 2021 and 2022 Reserve Capacity Cycles. The Reserve Capacity timetables for the 2021 and 2022 Reserve Capacity Cycles have been deferred¹⁴⁹ to accommodate these changes.

Key changes to the 2021 Reserve Capacity Cycle include:

- Introduction of the new Registration framework which includes new defined Facility Classes and Facility Technology Types. Changes to the Registration framework also enable the participation of hybrid Facilities which may contain multiple Separately Certified Components behind the same connection point.
- A new method to assign CRC to an ESR by measuring its Linearly De-rated Capacity, which is the maximum output the ESR can sustain across the Electric Storage Resource Obligation Duration.
- Introduction of Facility Sub-Metering for hybrid Facilities that contain multiple Separately Certified Components, to be used for the purposes of Reserve Capacity Testing and CRC.
- Removal of the Reserve Capacity Auction, with any capacity shortfalls being procured through the Supplementary Reserve Capacity process.

Network Access Quantity

The 2022 Reserve Capacity Cycle will introduce the NAQ framework which protects the Capacity Credits of existing Facilities from the entry of new Facilities. A NAQ, measured in MW, represents the network capacity available to the Facility at times of peak demand, and establishes a priority order for the assignment of Capacity Credits. A Facility must be assigned a NAQ to receive Capacity Credits. A new Facility will be assigned a NAQ only up to the residual capacity available in the network after accounting for the NAQs of existing Facilities. This will ensure Capacity Credits are assigned based on the transfer capability of the network.

The NAQ framework includes¹⁵⁰:

- The development of RCM Constraint Equations using RCM Limit Advice and Non-Thermal Network Limits. RCM Constraint Equations will represent the expected configuration of the network at 1 October of Year 3 of a Reserve Capacity Cycle, including new Facilities that have submitted an EOI, planned Facility retirements, and committed augmentations or retirements to the transmission network.

¹⁴⁶ ESR includes both large-scale storage resources connected to the transmission network, either standalone or co-located with another type of generation technology as part of a 'hybrid' Facility, and small-scale aggregated storage connected to the distribution network.

¹⁴⁷ ERA 2021, *Wholesale Electricity Market Rules*, at <https://www.era.gov.au/rule-change-panel/wholesale-electricity-market-rules>.

¹⁴⁸ The ETS has published an information paper in May 2021 on changes to support the implementation of constrained access and facilitate ESR participation in the RCM. See: <https://www.wa.gov.au/sites/default/files/2021-05/Information%20Paper%20Reserve%20Capacity%20Mechanism%20-%20Changes%20to%20support%20the%20implementation%20of%20constrained%20access%20and%20facilitate%20storage%20participation.pdf>.

¹⁴⁹ AEMO 2021, *2021 and 2022 Reserve Capacity timetables*. 26 February 2021, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/timetable/2021-and-2022-reserve-capacity-timetables.pdf?la=en.

¹⁵⁰ ETS 2020, *Assigning Capacity Credits in a Constrained Network*, Network Access Quantity - Key Design Parameters Information Paper, at www.wa.gov.au/sites/default/files/2020-03/Information%20Paper%20-%20Assigning%20Capacity%20Credits%20in%20a%20Constrained%20Network.pdf.

- The development of the NAQ Model which will incorporate RCM Constraint Equations, Facility dispatch scenarios, and a prioritisation order for the assignment of NAQs and Capacity Credits.
- The concept of a Network Augmentation Funding Facility (NAFF), which has funded the costs of augmenting the network. NAFFs will be prioritised to be assigned NAQs for the additional network capacity created by their augmentation.
- The concept of a Highest NAQ, which tracks the maximum NAQ ever assigned to a Facility and enables existing Facilities to be prioritised before new Facilities are assigned a NAQ (up to their Highest NAQ assuming the Facility's performance supports this). The Highest NAQ only decreases for poor performance of a Scheduled Facility.

7.2.3 WA DER Roadmap updates

The WA DER Roadmap was released by the WA Government's Energy Transformation Taskforce in April 2020. It set out a five-year plan to better integrate DER in the SWIS, including solar panels, battery storage, EVs, and active energy management systems.

The DER Roadmap Progress Report indicating the progress of the actions over the past 12 months was released in April 2021. Key highlights included¹⁵¹:

- Changes to the Australian Standard for inverters (AS/NZS 4777.2)¹⁵² in the SWIS, which will affect the autonomous settings of inverters installed from 1 July 2021¹⁵³. These changes will help maintain security and reliability in the SWIS.
- The installation of 13 community batteries with a storage capacity ranging between 105 kW/420 kWh and 116 kW/464 kWh by Western Power in Canning Vale, Dunsborough, Ellenbrook (two batteries), Kalgoorlie, Leda, Parmelia, Port Kennedy, Singleton, Two Rocks, Meadow Vale, Mandurah, and Wanneroo. These battery installations support the local distribution network while also providing the opportunity for Synergy to offer interested residential customers virtual storage services to store excess behind-the-meter PV electricity (see Section 7.5.2 below for more information)¹⁵⁴.
- Release of a Distribution Storage Opportunities Plan by Western Power, outlining an estimated amount of storage and other technology required to support the distribution network¹⁵⁵.
- Changes to the *Electricity Networks Access Code 2004*¹⁵⁶, improving opportunities for providers of network solutions to Western Power.
- Launch of the first WA DER Register¹⁵⁷ in April 2021, which will maintain specification data of distributed energy systems connected to the SWIS. This data set will enable¹⁵⁸:
 - AEMO to forecast, plan, and operate the power system more efficiently.
 - AEMO to understand how DER can be used to respond to major outage or disruption in the system and network.

¹⁵¹ EPWA, *DER Roadmap Progress Report*, April 2021, at www.wa.gov.au/sites/default/files/2021-04/EPWA_DER-Roadmap-progress-update_April2021_1.pdf.

¹⁵² AEMO 2021, *AS/NZS 4777.2 – Inverter Requirements standard*, at <https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/as-nzs-4777-2-inverter-requirements-standard>.

¹⁵³ See <https://www.westernpower.com.au/community/news-opinion/enabling-a-smoother-ride-for-solar-panel-uptake/>.

¹⁵⁴ Western Power 2021, *Community batteries*, at <https://www.westernpower.com.au/faqs/community-batteries/> and Synergy 2021, *PowerBank* at <https://www.synergy.net.au/Our-energy/For-tomorrow/PowerBank>.

¹⁵⁵ Western Power 2020, *Distribution Storage Opportunities Information Paper 2020*, at <https://www.westernpower.com.au/media/4659/distribution-storage-plan-wp201211.pdf>.

¹⁵⁶ WA Legislation 2021, *Electricity Networks Access Code 2004* (published 30 November 2004), at https://www.legislation.wa.gov.au/legislation/statutes/nsf/law_s37191.html.

¹⁵⁷ AEMO 2021, *DER Register data*, at <https://www.aemo.com.au/energy-systems/electricity/der-register/data-der>.

¹⁵⁸ AEMO 2021, *AEMO supports consumer choice for DER with the launch of the WA DER Register* (published 12 April 2021), at <https://aemo.com.au/newsroom/news-updates/wa-der-register>.

- Innovations with DER in WA, such as VPPs¹⁵⁹, and enabling customers to consider participating in new markets.
- Western Power to make better informed decisions about network investment options as demand changes and DER in WA increases.
- Industry players to better understand DER and factor this into their decision-making.
- Commencement of a time-of-use tariff pilot and progress on a second tariff pilot model.
- Progress of reviews on customer protections and data rights.
- Development of a DER orchestration pilot, known as Project Symphony, which will be implemented as a partnership between AEMO, Western Power, Synergy, and the Australian Renewable Energy Agency (ARENA). Project Symphony will demonstrate how large numbers of batteries, behind-the-meter PV, and large appliances (such as air-conditioners and electric hot water systems) can be co-ordinated into a VPP¹⁶⁰.
- Installation of strategic network investments, including 25 megavolt amperes of reactive power (MVAR) to help manage rising voltages. AEMO is working with Western Power on updates to the design and performance of the SWIS' Under Frequency Load Shedding (UFLS) scheme.

7.3 Infrastructure developments in the SWIS

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

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

7.3.1 Western Power's Applications and Queuing Policy

Western Power's Applications and Queuing Policy (AQP)¹⁶¹ 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.

7.3.2 Network access for generators

Several areas in the network have very limited network capacity¹⁶² 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) 2020¹⁶³ 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.

¹⁵⁹ 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.

¹⁶⁰ Government of Western Australia, *Virtual Power Plants to become a reality in WA-first*, Media Statement (3 February 2021), at <https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/02/Virtual-Power-Plants-to-become-a-reality-in-WA-first.aspx>.

¹⁶¹ At <https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/western-power-access-arrangement-period-2017-2022>.

¹⁶² Modelling the impacts of constrained network access, Public report, Public Utilities Office, 1 October 2018.

¹⁶³ At <https://www.westernpower.com.au/media/4768/annual-planning-report-2020-20210211v2.pdf>.

- Generator dispatch outcomes.
- Revenue projections.
- Generation supply adequacy.

The Generator Interim Access (GIA) solution, launched in July 2018, continues to provide interim constrained access connection for a limited number of renewable generators to facilitate further connections to the SWIS prior to Security Constrained Economic Dispatch (SCED) go live¹⁶⁴.

Renewable generation capacity totalling approximately 630 MW has been connected via the GIA since 2019, including Yandin wind farm (211.7 MW), the Warradarge wind farm (180.0 MW), and the Merredin solar farm (100.0 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, prior to the deployment of SCED in October 2022.

7.3.3 Connecting new loads

Both the Electricity Network Access Code and the WEM Rules contemplate application of non-network solutions to address network limitations. Non-network options may be provided by a Network Control Service (NCS), Dispatch Support Service (DSS), 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 are encouraged to contact Western Power to discuss these opportunities.

Western Power will publish the inaugural Network Opportunity Map (NOM) in October 2021 (and then every October annually). The NOM will highlight opportunities for third parties to deliver services to Western Power in the assessment of options to address network needs.

Western Power continues to work with large mining customers, local government, and other stakeholders to facilitate their energy needs, and is in the process of developing revised transmission network strategies. 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. The new transformer is expected to be commissioned in mid-2022.
- Undertaking several projects in the Eastern Goldfields region to increase network capacity in the area and facilitate providing supply to regional mining loads, including:
 - Replacement of static volt-ampere reactive (VAR) compensators¹⁶⁵ at West Kalgoorlie terminal.
 - Installing a third 220/132 kV transformer at West Kalgoorlie terminal and additional static synchronous compensators.

The projects above are expected to be completed by the end of 2021. Further details of the work being undertaken by Western Power can be found in its APR 2020¹⁶⁶.

¹⁶⁴ SCED is a process designed to meet electricity demand at the lowest cost, given the operational limitations of the generation fleet and transmission system. For more information about the development of SCED for the WEM see: <https://www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Energy-scheduling-and-dispatch-paper.pdf>.

¹⁶⁵ A VAR compensator is a set of electrical devices for providing fast-acting reactive power on high-voltage electricity transmission networks.

¹⁶⁶ See <https://www.westernpower.com.au/media/4768/annual-planning-report-2020-20210211v2.pdf>.

7.4 Maintaining power system security and reliability

This section presents current and emerging operational challenges for the operators of the SWIS.

7.4.1 Peaks, troughs, and ramp rates

During 2020, approximately 331 MW of additional behind-the-meter PV was connected to the SWIS, similar in capacity to the largest generation Facility connected to the SWIS (the 330.6 MW Newgen Neerabup power station¹⁶⁷). It is estimated that 1.74 GW¹⁶⁸ of behind-the-meter PV is connected to the SWIS as at April 2021.

Behind-the-meter PV is an uncontrollable generation source and is presenting an increasing challenge for the operators of the SWIS, as it drives:

- The minimum operational demand (trough) lower during the day, which is increasing the disparity between the trough and maximum operational demand (peak).
- An increasing rate of change (swings) as demand moves between the two extremes.

These rapid swings occur when behind-the-meter PV output decreases rapidly, necessitating a quick ramp up from large-scale generators to meet operational demand¹⁶⁹. This ramp up is frequently followed by a rapid increase in PV output requiring a quick ramp down of large-scale generation. These swings are demanding increasing agility from the generating fleet, and some units are not suited to this growing need¹⁷⁰.

When a large generation unit is requested to ramp up quickly from an “off-line” period, there is a higher risk of the unit failing. When coupled with tight reserve margins, there may not be adequate time to implement a contingency plan.

For example, on 8 December 2020, when reserve margins were tight, two large-scale generators went on Forced Outage due to failures following a request to start up, joining another large-scale generator already on Forced Outage for the same reason. This sequence of events did not lead to a supply shortfall, because the forecast peak load was lower than anticipated. However, it does highlight an increasing concern in managing operational challenges.

AEMO is undertaking additional analysis to ensure the capability of the available generation units is adequate to meet expected ramp rate requirements.

A combination of factors during a heatwave from 5 to 9 January 2021 presented the system operators with a challenging set of circumstances, a product of some of the issues presented above. Over the course of these dates:

- Muja C units 5 and 6, and Pinjar unit 10 (large-scale generation units) went on Forced Outages on 5 January 2021. Muja D unit 7 followed on 6 January 2021¹⁷¹.
- Operational demand was high on 7, 8 and 9 January 2021, driven by high temperatures and consequent air-conditioning load.
- Bushfires and thermal constraints limited the ability of some generators to export power.

An assessment of operational load indicated a potential reserves shortfall. AEMO executed procedures to:

- Expedite the return to service of large-scale generators from outage.
- Determine if other generators could increase generation.
- Assess ability of large customers to reduce load.

¹⁶⁷ Based on the TSOG rated at 41°C.

¹⁶⁸ PV installations as at April 2021 based on CER data, see Section 4.1.

¹⁶⁹ See Section 7.4.2.

¹⁷⁰ The ramp rate limit for large baseload generators is approximately 8 MW/min, a ramp rate which is increasingly required to maintain grid stability in the SWIS, see: WA Electricity Consultative Forum (WAEFCF) 14 April 2021 Meeting Pack, at <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/wa-electricity-consultative-forum-waecf>.

¹⁷¹ See <http://data.wa.aemo.com.au/#outages>.

- Prepare for potential involuntary load shedding.
- Understand any potential additional risks¹⁷².

These measures ensured that by the time operational demand reached the maximum peak of 3,789 MW at 18:00 on 8 January 2021 (seventh highest historical record), normal planning margins were achieved, and load shedding or additional actions were not required to maintain power system security.

The events leading to this operational challenge are not desirable, and while the heatwave may be unavoidable, future activities to mitigate such scenarios include:

- Those being implemented as part of the ETS, particularly those relating to the workstream “Delivering the Future Power System”, which focuses on modernising the WEM to enhance power system security and enable new generators’ access to the network (refer to Section 7.2 above).
- Continuous improvement of the methodology and delivery of the Long Term PASA (refer to Chapter 6).

7.4.2 Cloud cover and maintaining power system security and reliability

An emerging trend is the demand fluctuations created from rapid decreases in output from behind-the-meter PV connected to the SWIS. Fast moving cloudbanks over the SWIS result in rapid increases and then decreases in operational demand.

This was observed on 16 March 2021, where a fast-moving cloudbank quickly reduced behind-the-meter PV generation. This resulted in:

- A rapid increase in system load of approximately 300 MW within 30 minutes.
- Grid frequency dropping to 49.50 hertz (Hz)¹⁷³, a drop generally associated with the trip of a large generation unit.

7.4.3 Behind-the-meter PV tripping in response to system disturbances

A portion of behind-the-meter PV inverters cannot ride through power system disturbances and disconnect from the network, leading to a sudden loss of net generation and an increase in operational demand. This poses a system security risk, particularly when coupled with other generation contingencies.

AEMO is assessing these risks¹⁷⁴ to ensure there are provisions for additional reserves during periods of high-risk exposure, that is, when behind-the-meter PV trips in conjunction with a generation loss are likely to occur. In addition, AEMO is refining its understanding of the amount of behind-the-meter PV and load tripping that may follow network faults and net generation shortfall. This process will assist AEMO in determining the most appropriate solutions to manage the issue.

In response to the above, a new requirement for solar inverter systems has been introduced, forming part of the State Government’s ETS. The Australian Standard AS/NZS 4777.2:2020 has been revised to include a mandatory requirement for all new inverters to have a voltage disturbance ride-through capability¹⁷⁵.

7.4.4 Decommitment of large synchronous generators

The increasing uptake of behind-the-meter PV generation is resulting in lower minimum demands in the WEM. As a result, more synchronous generating units are being decommitted (as they are out of merit in the bid-stack¹⁷⁶).

¹⁷² See WAEFC 10 Feb 2021 Meeting Pack, at <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/wa-electricity-consultative-forum-waefc>.

¹⁷³ See Dispatch Advisory # 207921: <http://data.wa.aemo.com.au/#dispatch-advisory>.

¹⁷⁴ For more information see AEMO, *Behaviour of distributed resources during power system disturbances*, May 2021, at <https://www.aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf>.

¹⁷⁵ For more information see <https://www.westernpower.com.au/community/news-opinion/enabling-a-smoother-ride-for-solar-panel-uptake/>.

¹⁷⁶ This is the Balancing Merit Order, which is defined as “for a Trading Interval, the ordered list of Balancing Facilities, and associated quantities, used by AEMO for issuing Dispatch Instructions for the Trading Interval” in the WEM Rules.

Lower amounts of synchronous generation¹⁷⁷ leads to reduced essential system security services such as inertia, frequency control, system strength, and voltage control. AEMO needs to ensure that a minimum number of synchronous generators are online to provide the necessary system security requirements. In an effort to bolster system security services further, Western Power has committed to installing an additional 490 MVar of transmission and distribution level shunt reactors by the end of 2021 to mitigate against some of these voltage issues.

7.4.5 System restart after a system black event

A large-scale blackout of the power system is called a black system event¹⁷⁸. Stable load is required to restart the system. Large amounts of behind-the-meter PV may inhibit a system restart by reducing the amount of stable load available to support operation of synchronous generation units providing system restart services¹⁷⁹; that is, load may not be available at the substations along the preferred restoration path.

To mitigate this risk, AEMO and Western Power have revised the System Restart Plan to include a pathway with adequate load to restart the system even in the middle of the day¹⁸⁰.

7.4.6 Impact on Under-Frequency Load Shedding Scheme

The UFLS scheme is the last line of defence against frequency collapse. Western Power is responsible for configuring the UFLS scheme in accordance with section 2.4 of the Technical Rules¹⁸¹. The UFLS scheme disconnects loads dispersed across the SWIS to restore the supply-demand balance. There are five stages of load shedding in the UFLS scheme (starting at 48.75 Hz, and with 15% of load shed per stage). Each UFLS stage can operate partially or fully to disconnect as much load as necessary to stabilise the system frequency¹⁸². The loads shed in each stage are mainly sourced from distribution feeders serving non-essential commercial and residential customers.

High behind-the-meter PV output is reducing the quantity of load available for UFLS. AEMO has worked with Western Power to shift back-feeding and feeders with high penetration of behind-the-meter PV to later UFLS stages so Stage 1 and 2 UFLS are less compromised. Action 10 of the DER Roadmap is reviewing the UFLS scheme to identify additional actions.

7.5 Industry trends

7.5.1 Utility-scale batteries

Following changes to the WEM Rules to accommodate ESR (see Section 7.2.1), Market Participants are planning to build and connect utility-scale lithium-ion batteries to the SWIS.

Publicly announced projects include:

- A 380 MW peaking gas and diesel Facility in Wagerup, where Alinta has filed an application with the Waroona shire council to co-locate a 100 MW lithium-ion battery (storage capacity not yet announced).
- A 100 MW/200 MWh lithium-ion battery at a decommissioned power station in Kwinana, constructed and operated by Synergy.

¹⁷⁷ Synchronous generators are directly connected to the power system and rotate in synchronism with grid frequency. In WA, all operating synchronous generators are thermal generators (coal and gas Facilities).

¹⁷⁸ A system black event is a sudden, unexpected loss of a major source of supply which can cause very rapid changes in system frequency. In this event, networks and generators will automatically disconnect, or trip, in order to protect people and equipment from harm. See <https://www.aemc.gov.au/sites/default/files/content/b705e0e4-afd3-47ef-bc41-32ea3393629c/Fact-Sheet-Black-system-events.pdf>.

¹⁷⁹ AEMO 2019, *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS* (March 2019), at https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf.

¹⁸⁰ Revised System Restart Plan now targets the stable Perth inner metro loads (such as CBD) with lower exposure to DER.

¹⁸¹ Western Power 2021, Technical Rules, at <https://www.westernpower.com.au/industry/manuals-guides-standards/technical-rules/>.

¹⁸² AEMO 2020, *Investigation Report Under-Frequency Load Shedding Event on 10 January 2020 Report*, at https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2020/aemo-investigation-report---swis-ufls-event-10-january-2020.pdf?la=en.

ESR technology included in the two installations proposed above is expected to meet requests for the fast energy supply more rapidly than traditional synchronous generation. Fast energy supply will be delivered in response to ramp-up and ramp-down requests, used to maintain grid stability¹⁸³.

AEMO will actively participate in discussions on battery participation in the RCM and associated changes to the WEM Rules. AEMO will continue to engage with proponents contemplating the introduction of ESR in the SWIS, and will consider including prospective energy storage in future ESOOs.

7.5.2 Virtual energy storage services

A battery storage trial referred to as Powerbank 3 is offering up to 600 households access to virtual storage services for a daily subscription fee of \$1.20/day for 6 kWh of storage capacity or \$1.40/day for 8 kWh of storage capacity. Powerbank 3 will include the installation of nine 116 kW lithium-ion batteries connected at the distribution level within the community, at Ellenbrook, Kalgoorlie, Ashby, Canning Vale, Two Rocks, Vasse, Port Kennedy, Yokine, and Parmelia¹⁸⁴. Similar virtual storage services are located in Mandurah and Meadow Springs¹⁵⁴.

7.5.3 Hydrogen

Although hydrogen is a gas, its creation and consumption may affect electricity demand and/or supply in the SWIS by increasing load, providing an energy storage medium, and providing a mechanism to export renewable energy overseas. Hydrogen can be created from a range of methods. Two prominent methods are:

- Steam Methane Reforming (SMR), which separates hydrogen from methane and is referred to as blue hydrogen¹⁸⁵.
- Electrolysis, a process that splits water into hydrogen and oxygen via an electrolyser. When the electrolyser is powered by renewable energy, the hydrogen generated is referred to as green hydrogen¹⁸⁶.

A market for hydrogen and related products is expected to emerge in countries such as Japan and South Korea that have set net zero emission targets for 2050^{187, 188} and are expected to import green hydrogen to meet their emission free energy requirements. Consequently, it is anticipated that there will be a significant export market for green hydrogen from WA by 2030^{189,190}.

Green hydrogen products and projects in WA

- By replacing the traditional reducing agent (coking coal) with green hydrogen during the blast furnace stage of the steel-making process, oxygen combines with hydrogen to make water instead of combining with carbon to form carbon dioxide. This product is referred to as green steel¹⁹¹. The WA-based Fortescue Metals Group is planning to trial the use of green hydrogen as the reactant in the steel-making process with the objective of producing green steel on a commercial scale¹⁹².

¹⁸³ In response to increasing behind-the-meter PV and corresponding grid voltage and frequency volatility, the ramping frequency (ramping up and ramping down) of synchronous generators connected to the SWIS is increasing (see Section 7.4.1). For additional information regarding ESR technology and how it can help address increasing requests for fast response, see <https://hornsdalepowerreserve.com.au/learn/>.

¹⁸⁴ Western Power 2021, *Latest battery storage trial to benefit hundreds of WA homes* (updated 10 February 2021), at <https://www.westernpower.com.au/community/news-opinion/latest-battery-storage-trial-to-benefit-hundreds-of-wa-homes/>.

¹⁸⁵ Blue hydrogen is produced from natural gas, where the carbon emissions are captured and stored.

¹⁸⁶ Green hydrogen is produced from electrolysis from renewable energy.

¹⁸⁷ Japan and South Korea have set net-zero emission targets for 2050, in line with the European Union, and Japan is not intending to construct additional nuclear reactors in order to meet these net-zero emission targets. See <https://www.reuters.com/article/us-japan-nuclearpower-environment-idUKKBN27D0AN>.

¹⁸⁸ ACIL Allen Consulting 2018, *Opportunities for Australia from hydrogen export*, August 2018, at <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>.

¹⁸⁹ Department of Jobs, Tourism, Science and Innovation 2021, *Western Australian Renewable Hydrogen Strategy*, at https://www.wa.gov.au/sites/default/files/2021-01/WA_Renewable_Hydrogen_Strategy_2021_Update.pdf.

¹⁹⁰ Department of Jobs, Tourism, Science and Innovation 2020, *Western Australian Renewable Hydrogen Roadmap* (November 2020), at <https://www.wa.gov.au/sites/default/files/2020-12/Western%20Australian%20Renewable%20Hydrogen%20Roadmap%20-%20November%202020.pdf>.

¹⁹¹ Grattan Institute 2021, *Green steel is no longer a fantasy updated* (11 May 2020), at <https://grattan.edu.au/news/green-steel-is-no-longer-a-fantasy/>.

¹⁹² ABC News 2021, *Andrew Forrest on how green steel and hydrogen offer a chance to fix our climate and our economy* (25 January 2021), at <https://www.abc.net.au/news/2021-01-22/boyer-lecture-andrew-twiggy-forrest-green-hydrogen-climate/13077070>.

- Ammonia is used as a central ingredient in many fertilisers and is typically made from hydrogen derived from natural gas. An alternative production pathway combines green hydrogen and nitrogen to produce ammonia. Collaboration partners Yara International ASA (fertiliser producer) and Engie Renewables Australia Pty Ltd (Engie) are planning to connect a 10 MW electrolyser to an ammonia facility in Karratha, WA. The project has been awarded conditional funding from ARENA^{193,194}.
- ATCO is proposing to build a 10 MW electrolyser at the Warradarge wind farm in WA's Mid-West to produce four tonnes per day of green hydrogen. The green hydrogen will be trucked south to two locations for injection into the WA gas network. ARENA funding has been made available, subject to a final investment decision which is expected in December 2021¹⁹⁴.
- The WA Government aims to blend hydrogen with natural gas transported and consumed via the natural gas networks in WA. Hydrogen blending is expected to start in 2022 and rise to a hydrogen blend goal of 10% (10% hydrogen and 90% natural gas) by 2030¹⁹⁵. With an objective of decarbonising WA's gas sector, it is expected that hydrogen created from renewable energy via electrolysis will be used for blending. Hydrogen goals set by the WA Government have been articulated in the WA Renewable Hydrogen Strategy¹⁸⁹.

¹⁹³ ABC News 2020, *Fertiliser giant Yara aims to decarbonise food production with green hydrogen trial in Pilbara* (19 June 2020), at <https://www.abc.net.au/news/rural/2020-06-19/pilbara-yara-engie-trial-aims-make-sustainable-fertiliser-green/12340826>.

¹⁹⁴ ARENA 2021, *Over \$100 million to build Australia's first large-scale hydrogen plants* (5 May 2021), at <https://arena.gov.au/news/over-100-million-to-build-australias-first-large-scale-hydrogen-plants/>.

¹⁹⁵ See https://www.wa.gov.au/sites/default/files/2021-01/WA_Renewable_Hydrogen_Strategy_2021_Update.pdf.

A1. Supporting forecasts

AEMO engaged BIS Oxford to provide forecasts for WA GSP and population¹⁹⁶. AEMO developed the LIL forecasts in consultation with Western Power and specific LILs in the WEM.

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

A1.1 Economic growth outlook

BIS Oxford's outlook for WA

BIS Oxford applied a suite of models including 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 (imports and exports), financial variables (the United States 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 (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 considers the impact of climate change through three channels:

- Global temperature impact on depreciation of capital stock and production potential.
- Investment in energy efficiency improvements leading to productivity gains.
- Increased renewable penetration and pace of electrification; which has an effect on global demand for transitional emissions-intensive materials (coal, oil, and gas).

The recovery from the COVID-19 pandemic recession dominates the near-term economic outlook. While state governments have been able to relax restrictions considerably, enabling most sectors to resume normal activity levels, other sectors, such as hospitality and entertainment, continue to be exposed to the uncertainty of recurring restrictions. BIS Oxford assumes the vaccine rollout will provide some certainty, particularly with respect to internal state border restrictions, but it will not be sufficient for a full re-opening of the international border. Instead, the model assumed gradual re-opening of the international border, with normal levels of economic activity resuming from the first quarter of the 2022 calendar year.

BIS Oxford's low, expected, and high projections for GSP are presented in Table 15. These projections were applied to the low, expected, and high demand growth scenarios respectively.

Economic growth in WA is expected to be robust over the forecast horizon. With a compounded annual growth rate of 3.2% until the 2025-26 financial year, and 3.0% from 2025-26 to 2030-31. WA's GSP growth rate is projected to exceed the national average.

While mining production is set to decline in the near term, a new round of mining investment projects is expected to kick off in the next 12-24 months. Renewed mining activity will drive growth in investment spending and the construction sector. This will spill over to a number of other areas, including financial

¹⁹⁶ BIS Oxford, *2021 Macroeconomic Projections Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf?la=en.

services, rental, hiring, and real estate, and professional services. Increased economic activity will in turn encourage interstate migration and employment, feeding back into consumer-exposed sectors such as retail trade. Population growth in WA is forecast to exceed the national average in the long term.

Table 15 WA GSP (%) annual growth forecasts for different economic growth scenarios, 2021-22 to 2030-31 financial years^A

Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Low	-0.7	0.4	1.9	3.3	3.7	3.5	3.4	3.0	2.7	2.7
Expected	2.7	3.2	3.4	3.5	3.3	3.1	3.0	3.0	2.9	2.8
High	8.1	2.6	3.3	2.7	3.3	3.4	3.4	3.2	2.8	2.8

A. BIS Oxford's *2021 Macroeconomic Projections Report* adopts the NEM scenario mapping, which for the purposes of the WEM ESOO refers to the high demand growth scenario as Rapid Decarbonisation, expected demand growth scenario as Current Trajectory and low demand growth scenario as Slow Growth.

Source: BIS Oxford.

The low growth scenario is characterised by lower population growth, slower pace of technological progress and weaker investment growth compared to the expected scenario. The weaker mining outlook significantly impacts the outlook for WA, resulting in the state losing share of national gross domestic product (GDP).

The high growth scenario, characterised by strong decarbonisation objectives and moderate economic and population growth, projects in a loss in WA's share of national GDP relative to the expected scenario. This is due to the large role mining plays in the WA economy.

See BIS Oxford's report for more information on the methodology and assumptions for the WA GSP forecasts.

WA's economic recovery from the COVID-19 pandemic

WA's economy was the major performer among Australian states during the COVID-19 pandemic¹⁹⁷, due to strong state government support in the form of the \$5.5 billion WA Recovery Plan¹⁹⁸. Housing construction, Metronet, major road and infrastructure construction, building bonus grants, and apprenticeships received significant funding as part of the stimulus package, aiming to keep and create jobs in the construction sector.

Commodity prices rose significantly over the last financial year¹⁹⁹, which raised the value of mining sector output. As of December 2020, strong uptake in employment numbers resulted in the recovery of more than 90% of jobs lost from when the impact of COVID-19 restrictions peaked between February and May 2020²⁰⁰.

A1.2 Residential electricity connection forecasts

AEMO developed the residential connections forecast under low, expected, and high scenarios for the SWIS. The forecast annual growth rates for the three connections growth scenarios are outlined in Table 16 below.

The forecast was developed by using historical SWIS residential connection point growth rates together with BIS Oxford's dwelling construction forecasts. The short-term trend was blended (over a period of five years) with BIS Oxford's long-term forecast. Forecast new builds from BIS Oxford were split by building class and combined with the Australian Bureau of Statistics dwelling statistics²⁰¹ to forecast residential connections in each scenario.

¹⁹⁷ WA State Budget 2020-21, at <https://www.ourstatebudget.wa.gov.au/2020-21/fact-sheets/economy.pdf>.

¹⁹⁸ See <https://www.wa.gov.au/sites/default/files/2020-07/WA-Recovery-Plan.pdf>.

¹⁹⁹ RBA Index of Commodity Prices, at <https://www.rba.gov.au/statistics/frequency/commodity-prices/2021/icp-0321.html>.

²⁰⁰ Minister media statement, at <https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/01/WA-jobs-market-booming-as-Recovery-and-Jobs-plan-delivers.aspx#:~:text=In%20WA%2C%20employment%20has%20now.per%20cent%20in%20December%202020.>

²⁰¹ ABS. Census 2016, Dwelling Structure by Dwelling Type (SA2+), at http://stat.data.abs.gov.au/Index.aspx?DataSetCode=ABS_C16_T24_SA.

Table 16 Forecast residential connections growth (%) scenarios, 2021-22 to 2030-31 financial years

Scenario	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Low	1.4	1.4	1.5	1.7	1.6	1.6	1.7	1.8	1.9	1.8
Expected	1.5	1.5	1.7	1.9	2.0	1.9	1.9	1.9	1.9	1.9
High	1.6	1.6	1.9	2.2	2.3	2.1	2.0	1.9	2.0	2.1

A1.3 New large industrial loads

AEMO engaged with a range of stakeholders, including Western Power, in deciding to include prospective and committed LILs in the 2021 WEM ESOO. All new LIL²⁰² projects were evaluated on a graded scale according to:

- The project’s current state of progress through environmental approval stages.
- Western Power’s assessment on the likelihood of the project connecting to the SWIS.
- Whether the project proponent has publicly announced that it has taken a positive final investment decision and/or the project has commenced construction.

The graded scale was then used to classify projects based on their likelihood of progressing and ultimately connecting to the SWIS. The evaluation process yielded the following outcomes:

- A LIL graded as highly likely to connect to the SWIS was included in the low, expected, and high demand growth scenarios. These LILs were estimated to add approximately 382 GWh of electricity consumption annually relative to the 2019-20 base year.
- A LIL graded as moderately likely to connect to the SWIS was included in the expected and high demand growth scenarios. These LILs were estimated to add approximately 435 GWh of electricity consumption annually relative to the 2019-20 base year.
- A LIL graded as even chances to connect to the SWIS was included only in the high demand growth scenario. These LILs were estimated to add approximately 854 GWh of electricity consumption annually relative to the 2019-20 base year.

The graded scale approach is a methodological improvement in the 2021 WEM ESOO over the previously adopted decision-tree method. It considers a greater level of information available for each prospective project, both from Western Power’s assessment and the project’s approval stages.

Five projects were identified as new LILs²⁰³ and were included in the demand and operational consumption forecasts for the 2021 WEM ESOO. These include mineral processing plants and a major public infrastructure development. Two of the prospective LILs from the 2020 WEM ESOO have come online and have been included in this WEM ESOO’s operational consumption and demand forecasts.

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

- The LIL projects in the low demand growth scenario were forecast to add approximately 63 MW to peak demand by 2022-23 relative to the 2019-20 base year.
- The LIL projects in the expected growth scenario were forecast to add approximately 69 MW to peak demand by 2023-24 relative to the 2019-20 base year.
- The LIL projects in the high growth scenario were forecast to add approximately 150 MW to peak demand by 2024-25 relative to the 2019-20 base year.

²⁰² 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. For projects with multiple sites, this threshold is considered for the aggregate of the site loads.

²⁰³ AEMO calculated demand and energy consumption for new LILs based on their contracted maximum demand, adjusted by diversity factors.

A2. Forecast methodology and assumptions

A2.1 Overview

The peak demand and operational consumption forecasts for this WEM ESOO were developed in-house by AEMO.

The forecasting methodologies²⁰⁴ applied are consistent with those used for the 2020 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 observations and consultation with stakeholders²⁰⁵.

Development of the peak demand and operational consumption forecasts for this 2021 WEM ESOO was based on the forecasting methodologies outlined in the *Electricity Demand Forecasting Methodology Information Paper* (Methodology Information Paper)²⁰⁶. This section summarises the methodologies, focusing on the WEM-specific features and improvements compared to the 2020 WEM ESOO.

²⁰⁴ The minimum demand forecasts followed a similar approach to the peak demand forecasts.

²⁰⁵ AEMO recently consulted on the Electricity Demand Forecasting Methodology, and a final determination was published in May 2021, see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecast-methodology-final-determination.pdf.

²⁰⁶ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

Key definitions

Table 17 lists definitions for demand and energy consumption terms used in this WEM ESOO.

Table 17 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 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 (2021-22 to 2030-31 Capacity Years²⁰⁷).

These scenarios stem from different levels of economic growth and capture uncertainties in structural drivers, such as population and GSP growth. A summary of the key assumptions of structural drivers for each demand growth scenario is outlined in Table 18.

For the peak demand forecasts, AEMO modelled uncertainties due to random effects including weather conditions (primarily temperature²⁰⁸), seasonal effects, and random volatility. These uncertainties were modelled using a probability distribution where peak demand forecasts were expressed as three POE values from the probability distribution for each scenario, including²⁰⁹:

- 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.

For the 2020 WEM ESOO, the expected scenario DER forecasts were applied to the energy consumption and peak demand forecasts for all three economic growth scenarios. However, in the 2021 WEM ESOO, different

²⁰⁷ Minimum demand forecasts are developed under the low, expected, and high scenarios for a five-year outlook period from the 2021-22 to 2025-26 Capacity Years. See Section 5.2.

²⁰⁸ In the 2021 WEM ESOO, the peak demand forecast model has been based on the Perth Metro weather station (station identification number 9225). All historical temperature references in this WEM ESOO relate to the Perth Airport weather station (station identification number 9021).

²⁰⁹ Contrary to peak demand forecasts, for minimum demand forecasts, a 10% POE forecast represents nine years in 10 on average, demand would be expected to fall below this forecast, and a 90% POE forecast represents one year in 10 on average, demand would be expected to fall below this forecast.

DER forecasts were applied in each economic growth scenario to illustrate a wider range of outcomes. The high scenario DER forecasts assume that more rapid economic growth and strong government support compared to the expected scenario drives a higher DER installation rate, especially for behind-the-meter PV. Applying varying levels of DER uptake across the scenarios makes the WEM ESOO consistent with the NEM ESOO.

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.

Table 18 Key assumptions for expected, low and high demand forecasts

	Expected	Low	High
Demand drivers			
Economic and population growth forecasts Developed by BIS Oxford – see Appendix A1	Expected	Low	High
New LILs forecast Determined by AEMO – see Appendix A1	Expected	Low	High
Residential connections	Expected	Low	High
Energy efficiency	Expected	Low	High
DER uptake			
Behind-the-meter PV systems^A	Expected	Moderate, but elevated in short term	High
Behind-the-meter battery storage systems^A	Expected	Low	High
EVs^B	Expected	Low	High

A. The behind-the-meter PV and battery storage forecasts were developed by the CSIRO and GEM (See Section 4.2).

B. The EV forecasts were developed by CSIRO (See Section 4.2).

A2.1.1 Peak demand forecasts

This year AEMO integrated the WEM demand forecasting model into the broader NEM demand forecasting process. Last year’s model, while consistent with the broader NEM demand forecasting methodology, was run as a bespoke model because the WEM data had not been fully integrated. This year, WEM ESOO forecasting benefited from streamlining and process improvements that have been refined in the NEM in recent years.

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 demand and model the impact of DER. AEMO applied the GEV model to estimate the peak demand in the 2020-21 summer, the base year of the forecast²¹⁰. 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 2030-31.

²¹⁰ Actual demand data for the 2020-21 summer was available at the time of forecasting, however the base year was re-estimated by the GEV model to establish a probability distribution of operational peak demand to calculate the POE operational peak demand values.

Generalised Extreme Value model

The GEV model was fitted by applying weekly, fortnightly or monthly operational maximums as a function of behind-the-meter PV capacity (MW), customer connections, calendar effects, and weather. The GEV models were applied to simulate peak demand for each week, fortnight, or month, then this was aggregated to the seasonal peak demand (summer, winter, and shoulder). 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.

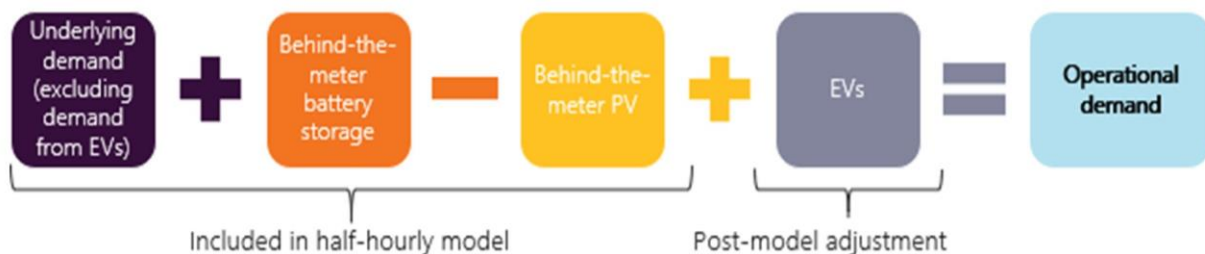
Half-hourly forecasting model

AEMO developed a half-hourly regression model for the peak demand forecasts for the 2021 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 elements²¹¹, then increased half-hourly heating load, cooling load, and base load by annual or seasonal growth indices. The indices were derived from projections on structural drivers including economic conditions (such as electricity price and GSP growth) and demographic conditions (such as connections growth).

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 corresponding demand value was then adjusted to reflect the impact of the modelled behind-the-meter PV and battery storage components. This result was adjusted post-modelling by the impact of EV operation. The operational demand forecasts accounted for the impact of generation of behind-the-meter PV and operation of behind-the-meter battery storage and EVs on underlying demand (see Figure 42).

Figure 42 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).

For each year of the outlook period, the half-hourly model was run for 5,000 simulated weather years. From the 5,000 simulated annual peak demand values, AEMO then extracted the 10% POE, 50% POE, and 90% POE peak values and associated peak timing.

This year, AEMO integrated the WEM minimum/maximum demand forecast process into the NEM simulation process, leveraging the climate change modelling developed in collaboration with BOM and CSIRO (discussed in Appendix A2.3 of the *Methodology Information Paper*). 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*.

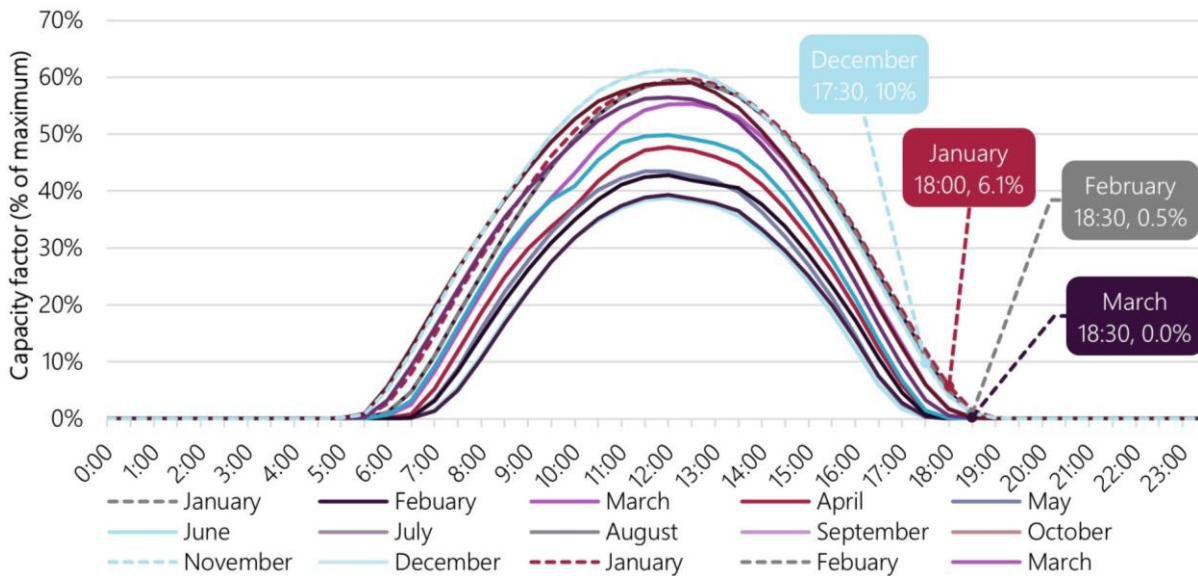
²¹¹ Heating/cooling load is defined as temperature dependent consumption (for example, electricity used for heating/cooling). Load that is independent of temperature (such as electricity used in cooking) is called base load or non-heating load.

Behind-the-meter PV modelling

AEMO models the expected effect of behind-the-meter PV on peak demand by incorporating behind-the-meter PV generation as a dependent variable in the half-hourly modelling of weather conditions, seasonal-effects, and stochastic volatility. By including underlying demand and behind-the-meter PV in the same half-hourly model, the simulated outcomes of each component aligned.

For the 2021 WEM ESOO, AEMO used estimated capacity factors at a half-hourly resolution from Solcast²¹² to calculate behind-the-meter PV capacity factors in the SWIS. Figure 43 shows the historical half-hourly solar capacity factor traces from 2012 to 2020 (calendar years), shown as a separate trace for each month.

Figure 43 Behind-the-meter PV capacity factors (monthly)^{A,B}



A. Based on historical data from Solcast (2012 to 2020 calendar years).

B. The coloured boxes indicate the most frequent Trading Intervals for daily peak demand over the 2019-20 Hot Season (and typical solar capacity factors at these times). For further information on peak demand Trading Intervals, see Chapter 3.

Source: AEMO calculations based on Solcast data.

The average yearly capacity factor calculated from the traces for the 2012 to 2020 calendar years is 15.5%.

This year, Solcast improved its cloud detection and thickness algorithm leading to some change in the profiles in Figure 43 relative to the 2020 WEM ESOO. In particular, Solcast now better accounts for the differences in imagery from the different operational satellites²¹³, and has improved the model's calibration against ground radiation measurement sites.

A2.1.2 Minimum demand forecasts

The methodology applied for minimum demand forecasts is similar to that applied for the peak demand forecasts; 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. This was done 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, for the 2021-22 to 2025-26 Capacity Years. See Section 5.2 for more details.

²¹² See <https://solcast.com/solar-radiation-data/inputs-and-algorithms/>.

²¹³ MTSAT-1R was used from 2005 to 2010; MTSAT-2 from 2010 to 2015; and Himawari-8 from 2015 to the present.

A2.1.3 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 18. These forecasts were segmented into two broad customer sectors, business and residential.

Business consumption forecasts

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

LILs 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 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 market participants 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 factors²¹⁴. Forecasts of these new LILs are detailed in Appendix A1.

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

Small to medium enterprises underlying consumption forecast

SME consumption forecasts²¹⁵ 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 a GSP economic driver.

The short-term model applied a linear regression model to forecast the SME underlying consumption by considering heating degree days (HDD)²¹⁶, cooling degree days (CDD)²¹⁷, and a dummy variable for COVID-19 in 2020. A heating benchmark temperature of 16°C and a cooling benchmark temperature of 21°C were used to calculate HDD and CDD. The short-term model predicted the weather-normalised 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, 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 a linear regression model based on the energy intensity (defined as GSP divided by SME energy usage on an annual basis) to determine the long-term relationship which was carried through the forecast horizon with the high and low demand growth scenarios having an approximate 10% variation by 2030 with respect to the expected demand growth scenario.

²¹⁴ Diversity factors are weightings applied to a new LIL's contracted maximum demand to account for different consumption levels during the load's operation.

²¹⁵ This covers any distribution-connected loads excluded from the LIL category.

²¹⁶ HDD is 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.

²¹⁷ CDD is 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.

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.
- The base load for each forecast period was estimated by applying the SME base load coefficient to the GSP and price projections.

A climate change index was applied by adjusting the heating and cooling load forecasts, where average temperature was adjusted by an increase of 0.03°C per year.

AEMO commissioned Strategy. Policy. Research. Pty Ltd to provide the energy efficiency forecasts for the 2021 WEM ESOO for residential and non-residential sectors.

The short-term and long-term models were then combined to produce a regional consumption forecast. The process for combining the two methods was a weighted average. The first year of the forecast applied a weighting of 100% to the trend-based forecast, dropping to 80% in year two and 60% in year three, through to 0% by year six.

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 44²¹⁸.

Figure 44 Adjustment process for final business operational consumption forecasts^A



A. Excluding network losses and consumption from EVs.

For more information on business consumption forecasts, see 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 connections²¹⁹ 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 calculated for a five-year period (2015-16 to 2019-20 financial years). The five-year period was chosen to capture the most recent residential consumption patterns and seasonality. A 95-5 confidence interval was included, providing dispersion between the low and the high demand growth scenario.
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 (with benchmarks at 21°C and 16°C

²¹⁸ The impact of battery storage on consumption is assumed to be negligible, aside from minor efficiency losses, and therefore not included.

²¹⁹ 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>.

respectively). 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 HDD²²⁰.

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 conditions²⁰⁶.
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 effect²²¹.
5. The forecasts were then scaled up with the connection growth forecast to project future base, heating, and cooling consumption over the forecast period²²².
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.
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.

For more information on residential consumption forecasts, see 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 2020 WEM ESOO, including:

- Increased robustness of the minimum and maximum demand forecasts by increasing the number of simulations from 1,000 to 5,000 runs for each modelled year.
- The SME model short-term trend and inclusion of energy intensity factors for the long term enabled short-term accuracy and the ability to model long-term structural changes that are occurring in the sector but may not be readily observable in the short term.
- The inclusion of a confidence interval in the residential model allows short-term dispersion in the forecast where there is some degree of uncertainty due to intra-year volatility.
- Surveys and interviews were conducted for more LILs to identify broad market dynamics affecting these loads, as well as industry-specific opportunities and threats.
- A graded scale approach for new LILs considers a greater level of information available for each prospective project, both from Western Power's assessment as well as more details on the project's approval stages. This is an improvement over the previously adopted decision tree method.

²²⁰ The coefficients represented the sensitivities of residential loads per connection to cool and warm weather respectively.

²²¹ 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.

²²² The connection forecast methodology has been refined with a split of residential and non-residential connections. Only the residential connections were used. For further information see Appendix A1.

A3. Reliability assessment methodology

This appendix provides a summary of the reliability methodology used to assess EUE, the Availability Class requirements, and Availability Curves for the 2021 Long Term PASA study. The methodology applied for the 2021 reliability assessment is broadly consistent with the 2020 reliability assessment, with the following improvements:

- Hourly load forecasting.
- Intermittent generation modelling.
- Account for full network constraints.
- Incorporate ESR capacity.

In this appendix, historical reference years refer to the 2015-16 to 2019-20 Capacity Years. The underlying and operational peak demand and energy consumption forecasts refer to the expected demand growth scenario.

A detailed description of the methodology and assumptions can be found in RBP's report²²³.

A3.1 Expected unserved energy assessment

The EUE assessment was undertaken with the aim of limiting EUE to no more than 0.002% of annual expected operational consumption for each Capacity Year in the 2021 Long Term PASA Study Horizon²²⁴. RBP carried out the assessment in three phases and applied a combination of time sequential capacity availability simulation and Monte Carlo analysis as follows:

- **Phase 1:** Undertake hourly load forecasting to develop five sets of hourly operational load forecasts for each Capacity Year in the Long Term PASA Study Horizon (for further information about the changes to this process compared to the 2020 EUE assessment, see Appendix A1.4).
 - Underlying historical load profiles were created for each of five historical reference years by adding historical behind-the-meter PV generation to operational demand.
 - The underlying load profiles for each reference year were scaled to the underlying 50% POE peak demand and energy consumption forecasts for each Capacity Year to develop hourly underlying load forecasts²²⁵.
 - Five sets of hourly behind-the-meter PV generation and battery storage charge/discharge contribution were forecast for each Capacity Year²²⁶.

²²³ RBP 2021. 2021 assessment of system reliability for the South West interconnected system, at <https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo>.

²²⁴ In accordance with the second component of the Planning Criterion outlined in clause 4.5.9(b) of the WEM Rules.

²²⁵ This creates five sets of hourly underlying load forecasts for each Capacity Year based on each of the five historical reference years' underlying load profiles' chronology and shapes.

²²⁶ Each set of forecasts was based on the hourly behind-the-meter PV capacity factor traces and battery storage charge/discharge profiles from each historical reference year and the installed behind-the-meter PV and battery storage capacity forecasts for the relevant Capacity Year in the outlook period.

- Preliminary operational load hourly forecasts were created by aggregating the forecast hourly behind-the-meter PV and battery storage contribution and the forecast hourly underlying load profiles²²⁷, and adjusting for network losses.
- The five preliminary operational load profiles were then scaled to the operational 50% POE peak demand and energy consumption forecasts to produce five hourly operational load forecasts for each Capacity Year.
- **Phase 2:** Run the simulation to calculate the EUE using the hourly operational load forecasts developed in Phase 1.
 - Time sequential capacity availability simulation was used to compare the total available capacity to the corresponding load in an hour.
 - The simulation assesses the capacity gap (available capacity minus load) for every hour of each Capacity Year sequentially, given a specific capacity mix, load profile, network constraints²²⁸, Planned Outage schedules, and randomly sampled Forced Outages.
 - Monte Carlo analysis was used to run the simulation with 50 Forced Outage iterations for each of the five forecast operational load profiles to generate a probability distribution of unserved energy. In total, 250 iterations were carried out for each Capacity Year.
 - Each iteration yielded an estimate of unserved energy. For each Capacity Year, the EUE was calculated as the average of the total estimates of unserved energy from the 250 iterations.
- **Phase 3:** Determine the amount of Reserve Capacity required to limit the EUE to 0.002% of the annual expected operational consumption forecast.
 - The EUE was calculated as a percentage of the annual expected operational consumption forecast for a given Capacity Year. If the percentage of unserved energy forecast for a given Capacity Year is less than or equal to 0.002% then the simulation is stopped and the RCT will be set by the first component of the Planning Criterion (WEM Rule 4.5.9(a)).
 - If the percentage of EUE is more than 0.002%, the capacity requirement calculated based on part (a) of the Planning Criterion is incrementally increased to reassess the EUE until EUE is less than or equal to 0.002%. The RCT will then be set by part (b) of the Planning Criterion.

A3.2 Minimum capacity requirements (Availability Classes)

RBP determined the minimum quantity of capacity required to be provided by Availability Class 1 for the 2022-23 and 2023-24 Capacity Years (the second and third years of the Long Term PASA Study Horizon) by simulating unserved energy as follows:

1. The load forecasts were developed using a similar load forecasting approach as described in Phase 1 under Section A1.1, but with the following differences:
 - Historical sent out generation for the five historical reference years was used to develop an average underlying load shape. This was then applied to the 2019-20 Capacity Year's load chronology and scaled to the underlying 50% POE peak demand and energy consumption forecasts to produce a single forecast underlying load profile.
 - Historical hourly behind-the-meter PV capacity factor traces and battery capacity charge/discharge profiles from the five historical reference years were used to develop an average historical behind-the-meter PV capacity factor trace and battery capacity charge/discharge profile.

²²⁷ Forecast hourly behind-the-meter PV generation was netted off the forecast hourly underlying load profiles. Forecast hourly battery contribution was subtracted from (when discharging) or added to (when charging) the forecast hourly underlying load profiles.

²²⁸ The 2021 reliability study has considered the network constraints that apply to Constrained Access Facilities under the GIA arrangement for the 2021-22 Capacity Year and full constrained network access from 1 October 2022.

- A single operational load profile was forecast by aggregating the hourly underlying load forecasts and the hourly behind-the-meter PV and battery storage contributions. This operational load profile was then adjusted for network losses and scaled to meet the operational 50% POE peak demand and energy consumption forecasts.
2. Availability Class 2 capacity is modelled in greater detail to account for the availability constraints of DSM²²⁹ and ESR capacity. In summary:
 - For the 2022-23 Capacity Year, Availability Class 2 capacity was comprised solely of DSM capacity, as no stand-alone ESR capacity holds Capacity Credits for the 2022-23 Capacity Year.
 - For the 2023-24 Capacity Year, Availability Class 2 capacity included both stand-alone ESR and DSM capacity.
 - ESR was dispatched first to reduce demand, with availability restricted to the period between 16:00 and 20:00 (see Section 6.3 for further information).
 - DSM capacity was then dispatched optimally to reduce residual peak demand, subject to availability and scheduling constraints.
 3. 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).
 4. Forced Outages were removed from the model to avoid double-counting, since the reserve requirement already accounts for Forced Outages.
 5. The model was iterated to increase or reduce the amount of Availability Class 2 capacity (capped at the RCT) until the 0.002% EUE limit was violated.

The quantity of energy producing capacity where the EUE equals 0.002% of the expected operational consumption sets the minimum Availability Class 1 requirement. The Availability Class 2 requirement is calculated by subtracting the Availability Class 1 requirement from the RCT.

A3.3 Availability Curves

For the 2021 WEM ESOO, the Availability Curves were determined for the 2022-23 and 2023-24 Capacity Years (the second and third Capacity Years in the Long Term PASA Study Horizon). RBP determined the Availability Curves by:

- Using the operational load profiles for the 2022-23 and 2023-24 Capacity Years developed in Phase 1 of the EUE assessment 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 load duration curve (LDC).
- 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.

²²⁹ Excluding Interruptible Load used to provide Spinning Reserve.

A3.4 Methodology changes and improvements

In consultation with AEMO, RBP made several methodology changes and improvements for the 2021 reliability assessment. In summary:

- **Hourly load forecasting** – behind-the-meter PV and battery storage uptake are expected to change the shape of the load profile in the SWIS over the Long Term PASA Study Horizon, so the load forecasting modelling has been updated. To align with the changes to the intermittent generation profiles and account for the correlation between behind-the-meter PV and battery storage operation, utility-scale intermittent generation, and weather conditions, hourly load forecasts were developed for each of the five reference years.
- **Intermittent generation profiles** – to better account for intermittent generation’s variability and the potential effects on unserved energy, intra-day hourly profiles for each historical reference year were created based on historical generation data or estimates for new Facilities. A total of 60 intra-day hourly profiles (one profile for each month for each reference year) was used for each intermittent generator. The increased number of profiles (compared to only one monthly profile for each generator in the 2020 WEM ESOO) provides a more comprehensive representation of the level of intermittent generator variability.
- **Constraint modelling** – the SWIS has historically operated on an unconstrained basis, except for the GIA generators, which were incorporated in the 2020 reliability modelling. For the 2021 reliability modelling, full network constraints were modelled from 1 October 2022 by creating a constraint optimisation model²³⁰ that maximises total available generation subject to network constraints, the unconstrained available generation from each Facility, and hourly load.
- **Incorporation of ESR** – the WEM Amendment (Tranche 2 and 3 Amendments) Rules 2020 introduced a new participation framework for ESR in the RCM. ESR has been accounted for as a supply source in the 2021 EUE assessment. For the 2021 Availability Classes modelling, stand-alone ESR has been considered as Availability Class 2 capacity.

Further information about the methodology changes and improvements can be found in RBP’s report¹¹⁶.

²³⁰ This constraint optimisation model is only heuristically applied when there is a risk of or unserved energy in the EUE assessment, as unserved energy is extremely unlikely in periods of low-load.

B1. Supply-demand balance

Table 19 Supply-demand balance, low demand growth scenario (MW)

Capacity Year	RCT ^A	Committed capacity	Balance	
2021-22		4,229	4,925	696
2022-23		4,169	4,807	638
2023-24		4,130	4,807	677
2024-25		4,092	4,614	522
2025-26		4,076	4,614	538
2026-27		4,050	4,614	564
2027-28		4,016	4,614	598
2028-29		3,985	4,614	629
2029-30		3,949	4,614	665
2030-31		3,898	4,614	716

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

Table 20 Supply-demand balance, expected demand growth scenario (MW)

Capacity Year	RCT ^A	Committed capacity	Balance	
2021-22 ^B		4,356	4,925	569
2022-23 ^B		4,380	4,807	427
2023-24		4,396	4,807	411
2024-25		4,409	4,614	205
2025-26		4,410	4,614	204
2026-27		4,427	4,614	187
2027-28		4,432	4,614	182
2028-29		4,441	4,614	173
2029-30		4,444	4,614	170
2030-31		4,443	4,614	171

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 4,482 MW set in the 2019 WEM ESOO for the 2019 Reserve Capacity Cycle and the RCR of 4,421 MW set in the 2020 WEM ESOO for the 2020 Reserve Capacity Cycle do not change.

Table 21 Supply-demand balance, high demand growth scenario (MW)

Capacity Year	RCT ^A	Committed capacity	Balance	
2021-22		4,435	4,925	490
2022-23		4,500	4,807	307
2023-24		4,541	4,807	266
2024-25		4,591	4,614	23
2025-26		4,628	4,614	-14
2026-27		4,693	4,614	-79
2027-28		4,766	4,614	-152
2028-29		4,857	4,614	-243
2029-30		4,980	4,614	-366
2030-31		5,100	4,614	-486

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

B2. Expected unserved energy assessment results

Table 22 EUE assessment results

Capacity Year	Operational consumption (MWh) ^A	0.002% of operational consumption (MWh)	EUE (MWh)	EUE (%)
2021-22	17,127,210	343	4	<0.002
2022-23	17,018,680	340	4	<0.002
2023-24	16,841,560	337	1	<0.002
2024-25	16,666,840	333	8	<0.002
2025-26	16,521,750	330	2	<0.002
2026-27	16,395,180	328	9	<0.002
2027-28	16,263,580	325	4	<0.002
2028-29	16,160,460	323	9	<0.002
2029-30	16,050,720	321	39	<0.002
2030-31	15,986,800	320	5	<0.002

A. These values are the operational consumption forecasts developed under the expected demand growth scenario; see Chapters 5 and 6 for more information.

Source: AEMO and RBP.

B3. Summer peak demand forecasts

Table 23 Summer peak demand forecasts under the low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,790	3,570	3,363
2022-23	3,726	3,517	3,318
2023-23	3,687	3,477	3,275
2024-25	3,649	3,447	3,248
2025-26	3,633	3,416	3,226
2026-27	3,607	3,404	3,205
2027-28	3,573	3,365	3,167
2028-29	3,542	3,342	3,149
2029-30	3,506	3,299	3,100
2030-31	3,455	3,261	3,067
Average growth	-1.0%	-1.0%	-1.0%

Table 24 Summer peak demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,917	3,686	3,476
2022-23	3,937	3,708	3,507
2023-23	3,953	3,733	3,516
2024-25	3,966	3,736	3,527
2025-26	3,967	3,739	3,530
2026-27	3,984	3,755	3,539
2027-28	3,989	3,750	3,535
2028-29	3,998	3,767	3,544
2029-30	4,001	3,769	3,545
2030-31	4,000	3,772	3,554
Average growth	0.2%	0.3%	0.2%

Table 25 Summer peak demand forecasts under the high demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,996	3,752	3,535
2022-23	4,057	3,820	3,610
2023-23	4,098	3,872	3,657
2024-25	4,148	3,915	3,694
2025-26	4,185	3,950	3,733
2026-27	4,250	4,012	3,790
2027-28	4,323	4,080	3,853
2028-29	4,414	4,173	3,945
2029-30	4,537	4,298	4,064
2030-31	4,657	4,421	4,198
Average growth	1.7%	1.8%	1.9%

B4. Winter peak demand forecasts

Table 26 Winter peak demand forecasts under the low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,271	3,174	3,061
2022-23	3,245	3,149	3,043
2023-23	3,224	3,125	3,020
2024-25	3,202	3,100	3,000
2025-26	3,181	3,084	2,977
2026-27	3,151	3,053	2,950
2027-28	3,107	3,014	2,911
2028-29	3,067	2,972	2,869
2029-30	3,004	2,904	2,797
2030-31	2,949	2,844	2,740
Average growth	-1.1%	-1.2%	-1.2%

Table 27 Winter peak demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,382	3,273	3,163
2022-23	3,417	3,312	3,200
2023-23	3,436	3,332	3,222
2024-25	3,443	3,335	3,224
2025-26	3,439	3,329	3,215
2026-27	3,446	3,329	3,213
2027-28	3,425	3,321	3,205
2028-29	3,436	3,321	3,204
2029-30	3,419	3,298	3,186
2030-31	3,415	3,289	3,171
Average growth	0.1%	0.1%	0.0%

Table 28 Winter peak demand forecasts under the high demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	3,445	3,327	3,217
2022-23	3,521	3,411	3,295
2023-23	3,571	3,459	3,347
2024-25	3,605	3,493	3,379
2025-26	3,655	3,528	3,413
2026-27	3,699	3,576	3,459
2027-28	3,776	3,655	3,540
2028-29	3,866	3,747	3,629
2029-30	4,009	3,886	3,770
2030-31	4,115	3,998	3,885
Average growth	2.0%	2.1%	2.1%

B5. Minimum demand forecasts

Table 29 Minimum demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2021-22	787	734	683
2022-23	615	574	520
2023-24	480	442	386
2024-25	366	331	271
2025-26	267	232	168
Average growth	-23.7%	-25.0%	-29.6%

B6. Operational consumption forecasts

Table 30 Operational consumption forecasts (GWh)

Capacity Year	Low	Expected	High	
2021-22		15,987	17,127	17,963
2022-23		15,266	17,019	18,069
2023-24		14,660	16,842	17,825
2024-25		14,118	16,667	17,496
2025-26		13,719	16,522	17,219
2026-27		13,469	16,395	17,128
2027-28		13,237	16,264	17,309
2028-29		13,023	16,160	17,584
2029-30		12,818	16,051	17,948
2030-31		12,645	15,987	18,435
Average growth		-2.6%	-0.8%	0.3%

B7. Power station information in the SWIS

Table 31 Scheduled Generators in the SWIS, 2019-20 Capacity Year

Market Participant	Power station (units included)	Classification	Energy generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%) ^B
Alcoa of Australia	Alcoa Wagerup	Baseload	144.03	0.82	26	0.54
Alinta Sales	Alinta Pinjarra (1 and 2)	Baseload	1816.47	10.31	270.5	5.61
	Alinta Wagerup (1 and 2)	Mid-merit	800.00	4.54	392	8.13
Bluewaters Power 1 Bluewaters Power 2	Bluewaters (1 and 2)	Baseload	3190.77	18.11	434	9.00
Goldfields Power	Parkeston	Mid-merit	62.65	0.36	59.4	1.23
Landfill Gas and Power	Kalamunda	Peaking	0.00	0.00	1.3	0.03
Merredin Energy	Merredin	Peaking	0.27	0.00	82	1.70
NewGen Neerabup Partnership	NewGen Neerabup	Mid-merit	427.84	2.43	330.6	6.86
NewGen Power Kwinana	NewGen Kwinana	Baseload	1679.35	9.53	327.8	6.80
Southern Cross Energy	Southern Cross	Baseload	149.73	0.85	20	0.41
Synergy	Cockburn	Mid-merit	192.23	1.09	240	4.98
	Collie	Baseload	944.32	5.36	317.2	6.58
	Kemerton (11 and 12)	Peaking	82.02	0.47	310	6.43
	Kwinana GT (2 and 3)	Baseload	800.56	4.54	197.7	4.10
	Muja CD (5 to 8)	Baseload	3483.63	19.77	810	16.80
	Mungarra (1 and 3) ^A	NA	8.45	0.05	0	0.00
	Perth Power Partnership Kwinana	Baseload	508.64	2.89	80.4	1.67
	Pinjar (1 to 5, 7)	Peaking	48.20	0.27	209	4.33
Pinjar (9 to 11)	Mid-merit	470.58	2.67	346	7.18	

Market Participant	Power station (units included)	Classification	Energy generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%) ^B
	West Kalgoorlie (2 and 3) ^A	NA	6.85	0.04	0	0.00
Tesla Corporation Management	Tesla Picton	Peaking	0.03	0.00	9.9	0.21
Tesla Geraldton	Tesla Geraldton	Peaking	0.02	0.00	9.9	0.21
Tesla Kemerton	Tesla Kemerton	Peaking	0.03	0.00	9.9	0.21
Tesla Northam	Tesla Northam	Peaking	0.01	0.00	9.9	0.21
Tronox Management	Tiwest Cogeneration	Baseload	246.34	1.40	36	0.75
Western Energy	Perth Energy Kwinana	Mid-merit	111.09	0.63	109	2.26

A. Registered Facilities that that did not participate in the RCM for the 2019-20 Capacity Year.

B. The Capacity Credits share (%) is calculated from a total of 4,821.97 MW of Capacity Credits assigned to Scheduled Generators and INSGs for the 2019-20 Capacity Year. A total of 4,887.970 MW of Capacity Credits were assigned for the 2019-20 Capacity Year, including 66.000 MW of Capacity Credits assigned to DSPs.

Table 32 INSGs in the SWIS, 2019-20 Capacity Year

Market Participant	Power station (units included)	Energy Source	Maximum Capacity (MW)	Energy generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%) ^B
Alinta Sales	Walkaway	Wind	89.10	313.19	1.78	24.75	0.51
	Badgingarra	Wind/solar	130.00	536.25	3.04	35.63	0.74
	Yandin ^A	Wind	211.68	84.93	0.48	0.00	0.00
BEI WWF ATF WWF Trust	Warradarge ^A	Wind	180.00	39.06	0.22	0.00	0.00
Blair Fox	Beros Road Wind Farm ^A	Wind	9.25	14.51	0.08	0.00	0.00
	Karakin	Wind	5.00	5.40	0.03	0.74	0.02
	West Hills ^A	Wind	5.00	2.32	0.01	0.00	0.00
CleanTech Energy	Richgro Biogas	Landfill gas	2.00	3.56	0.02	1.65	0.03
Collgar Wind Farm	Collgar	Wind	206.00	673.24	3.82	18.85	0.39
Denmark Community Windfarm	Denmark Wind Farm	Wind	1.44	5.57	0.03	0.51	0.01
EDWF Manager	Emu Downs	Wind/solar	80.00	291.19	1.65	30.08	0.62
Landfill Gas and Power	Red Hill	Landfill gas	3.64	20.91	0.12	2.79	0.06
	Tamala Park	Landfill gas	4.80	32.48	0.18	4.17	0.09
Merredin Solar Farm Nominee	Merredin	Solar	100.00	15.69	0.09	29.32	0.61

Market Participant	Power station (units included)	Energy Source	Maximum Capacity (MW)	Energy generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%) ^B
Metro Power Company	AmbriSolar ^A	Solar	0.96	2.10	0.01	0.00	0.00
Mt. Barker Power Company	Mount Barker	Wind	2.43	7.03	0.04	0.69	0.01
Mumbida Wind Farm	Mumbida	Wind	55.00	193.54	1.10	9.97	0.21
Northam Solar Project Partnership	Northam	Solar	9.8	22.30	0.13	3.75	0.08
Perth Energy	Rockingham	Landfill gas	4.00	13.23	0.08	2.12	0.04
	South Cardup	Landfill gas	4.16	21.45	0.12	2.94	0.06
SRV AGWF Pty Ltd as trustee for AGWF Trust	Albany	Wind	21.60	58.42	0.33	6.61	0.14
	Grasmere	Wind	13.80	41.79	0.24	4.51	0.09
	Greenough River	Solar	40.00	33.66	0.19	2.00	0.04
Synergy	Bremer Bay	Wind	0.60	1.80	0.01	0.20	0.00
	Kalbarri	Wind	1.60	2.67	0.02	0.34	0.01
Waste Gas Resources	Henderson	Landfill gas	3.00	12.01	0.07	1.85	0.04

A. Registered Facilities that that did not participate in the RCM for the 2019-20 Capacity Year.

B. The Capacity Credits share (%) is calculated from a total of 4,821.97 MW of Capacity Credits assigned to Scheduled Generators and INSGs for the 2019-20 Capacity Year. A total of 4,887.970 MW of Capacity Credits were assigned for the 2019-20 Capacity Year, including 66.000 MW of Capacity Credits assigned to Demand Side Programmes.

B8. Facility capacities

Table 33 Registered generation Facilities – existing and committed (MW)

Market Participant	Facility	Capacity Credits (2022-23)	Maximum Capacity
Alcoa of Australia Limited	ALCOA_WGP	26.000	26.000
Alinta Sales	ALINTA_PNJ_U1	142.450	143.000
Alinta Sales	ALINTA_PNJ_U2	142.450	143.000
Alinta Sales	ALINTA_WGP_GT	196.000	196.000
Alinta Sales	ALINTA_WGP_U2	196.000	196.000
Alinta Sales	ALINTA_WWF	15.546	89.100
Alinta Sales	BADGINGARRA_WF1	26.203	130.000
Alinta Sales	YANDIN_WF1	34.109	211.680
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1	30.223	180.000
Blair Fox Pty Ltd AFT The Blair Fox Trust	BLAIRFOX_BEROSRD_WF1 ^B	0.000	9.252
Blair Fox Pty Ltd AFT The Blair Fox Trust	BLAIRFOX_KARAKIN_WF1	0.452	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	0.821	2.000
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	21.847	206.000
Denmark Community Windfarm Ltd	DCWL_DENMARK_WF1	0.418	1.440
East Rockingham RRF Project Co	ERRRF_WTE_G1 ^A	25.134	29.000
EDWF Manager	EDWFMAN_WF1	14.664	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	RED_HILL	2.767	3.640
Landfill Gas and Power	TAMALA_PARK	4.349	4.800
Merredin Energy	NAMKKN_MERR_SG1	82.000	92.600
Merredin Solar Farm Nominee	MERSOLAR_PV1	13.730	100.000

Market Participant	Facility	Capacity Credits (2022-23)	Maximum Capacity
Metro Power Company	AMBRISOLAR_PV1	0.878	0.960
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.578	2.430
Mumbida Wind Farm	MWF_MUMBIDA_WF1	7.039	55.000
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600	342.000
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	334.800	335.000
Northam Solar Project Partnership	NORTHAM_SF_PV1	1.569	9.800
Perth Energy	ROCKINGHAM	2.245	4.000
Perth Energy	SOUTH_CARDUP	2.914	4.158
Southern Cross Energy	STHRNCRS_EG	21.012	23.000
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	5.545	21.600
SRV AGWF Pty Ltd as trustee for AGWF Trust	GRASMERE_WF1	3.875	13.800
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	6.360	40.000
Synergy	BREMER_BAY_WF1	0.178	0.600
Synergy	COCKBURN_CCG1	240.000	249.700
Synergy	COLLIE_G1	317.200	318.300
Synergy	KALBARRI_WF1	0.245	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_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	31.000	38.500
Synergy	PINJAR_GT10	110.500	118.150
Synergy	PINJAR_GT11	124.000	130.000
Synergy	PINJAR_GT2	30.500	38.500
Synergy	PINJAR_GT3	37.000	39.300
Synergy	PINJAR_GT4	37.000	39.300

Market Participant	Facility	Capacity Credits (2022-23)	Maximum Capacity
Synergy	PINJAR_GT5	37.000	39.300
Synergy	PINJAR_GT7	37.000	39.300
Synergy	PINJAR_GT9	111.000	118.150
Synergy	PPP_KCP_EG1	80.400	90.000
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	36.000	42.100
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	1.588	3.000
Western Energy	PERTHENERGY_KWINANA_GT1	109.000	116.000

A. Candidates for Registration that hold Capacity Credits for the 2022-23 Capacity Year.

B. Registered Facilities that did not participate in the RCM for the 2022-23 Capacity Year.

Table 34 Registered DSM Facilities – capability and availability

Market Participant	Facility	Capacity Credits (2022-23)
Bluewaters Power 1	GRIFFINP_DSP_01	20.000
Synergy	SYNERGY_DSP_04	42.000
Wesfarmers Kleenheat Gas	PREPWR_DSP_02	24.000

Measures and abbreviations

Units of measure

Abbreviation	Unit of measure
GW	Gigawatt
GWh	Gigawatt hour
Hz	Hertz
kV	Kilovolt
kVA	Kilovolt-amperes
kW	Kilowatt
kWh	Kilowatt hour
MVA _r	Megavolt-ampere reactive
MW	Megawatt
MWh	Megawatt hour
VAR	volt-ampere reactive
W	Watt

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
AQP	Applications and Queuing Policy
ARENA	Australian Renewable Energy Agency
BESS	Battery energy storage system
BEV	Battery electric vehicle
BIS Oxford	BIS Oxford Economics

Abbreviation	Expanded name
BOM	Bureau of Meteorology
BRCP	Benchmark Reserve Capacity Price
CDD	Cooling degree day
CER	Clean Energy Regulator
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DEBS	Distribution Energy Buy Back Scheme
DSM	Demand Side Management
DSP	Demand Side Programme
DSS	Dispatch Support Service
EOI	Expressions of Interest
EPWA	Energy Policy Western Australia
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resources
ESS	Essential System Service
ETS	Energy Transformation Strategy
EUE	Expected unserved energy
EV	Electric vehicle
GDP	Gross Domestic Product
GEM	Green Energy Markets
GEV	Generalised Extreme Value
GIA	Generator Interim Access
GSP	Gross state product
HDD	Heating degree day
INSG	Intermittent Non-Scheduled Generator
IRCR	Individual Reserve Capacity Requirement
LDC	Load duration curve
LFAS	Load Following Ancillary Service
LIL	Large Industrial Load
NAFF	Network Augmentation Funding Facility

Abbreviation	Expanded name
NAQ	Network Access Quantity
NEM	National Electricity Market
NCS	Network Control Services
NOM	Network Opportunity Map
Outlook period	2021-22 to 2030-31 Capacity Years
PASA	Projected Assessment of System Adequacy
PHEV	Plug-in hybrid electric vehicle
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic Non-Scheduled Generator
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
RLM	Relevant Level Methodology
SCED	Security Constrained Economic Dispatch
SME	Small and medium-sized enterprises
SMR	Stream Methane Reformation
SPR	Strategy.Policy.Research
SWIS	South West interconnected system
TSOG	Total Sent Out Generation
UFLS	Under Frequency Load Shedding
VDRT	voltage disturbance ride-through
VPP	Virtual Power Plant
WA	Western Australia
WACC	Weighted Average Cost of Capital
WAECF	Western Australian Electricity Consultative Forum
WEM	Wholesale Electricity Market
WoSP	Whole of System Plan

Glossary

This document uses many terms that have meanings defined in the WEM Rules. The WEM meanings are adopted unless otherwise specified.

Term	Definition
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 day (CDD)	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.
Distributed Energy Resources (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.
Expression/s of interest (EOI)	An annual call out for expressions of interest from new generation or demand side management (DSM) Facilities that may seek Certified Reserve Capacity (CRC) and Capacity Credits for the relevant Capacity Year.
Expected Unserved Energy (EUE)	An estimate of the amount of Unserved Energy in the SWIS.
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 Energy Transformation Strategy), and the GIA tool will be decommissioned.
heating degree day (HDD)	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.
installed capacity	The generating capacity (in megawatts (MW)) of a single or multiple generating units.
Large Industrial Loads (LILS)	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.
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.

Term	Definition
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 megawatts (MW) and averaged over a 30-minute period. It is reported on a "sent-out" basis and calculated as the Total Sent Out Generation (TSOG) x 2 to convert megawatt hour (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 (POE)	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
reliability standard	The reliability standard for generation and inter-regional transmission elements in the NEM is defined as a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
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.
Total Sent Out Generation (TSOG)	Electricity referred to as 'sent-out' excludes electricity used by a generator. Electricity used by a generator may be called 'auxiliary load', 'parasitic load', or 'self-load', referring to energy generated for use within power stations.
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.