Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2019
Issues paper

7 November 2019

Economic Regulation Authority
WESTERN AUSTRALIA

D208540

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Monday, 16 December 2019

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

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Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

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1. Introduction

Each year, the ERA reviews and prepares a report for the Minister for Energy on how effectively the Wholesale Electricity Market (WEM) meets its objectives.

The Wholesale Electricity Market Rules require the report to the Minister to contain the following:[1]

- A summary of the information and data listed in Market Rule 2.16.1. This is the data the Australian Energy Market Operator (AEMO) must provide to the ERA in the Market Surveillance Data Catalogue.
- The ERA's assessment of the effectiveness of the market, including how effectively AEMO carries out its functions, with discussion of the following:
  - Reserve Capacity Market
  - market for bilateral contracts for capacity and energy
  - Short Term Energy Market
  - Balancing Market
  - dispatch processes
  - planning processes
  - administration of the market, including the Market Rule change process
  - compliance monitoring and enforcement
  - ancillary services.
- An assessment of any events or behaviour that influenced the effectiveness of the market.
- Any recommended measures to increase how effectively the market meets the WEM objectives for the Minister for Energy to consider.

The ERA may also address other issues not included above.

The WEM objectives are to:

1. Promote the economically efficient, safe and reliable production and supply of electricity and electricity-related services in the South West Interconnected System (SWIS).
2. Encourage competition among generators and retailers in the SWIS, including by facilitating the efficient entry of new competitors.
3. Avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or reduce overall greenhouse gas emissions.
4. Minimise the long-term cost of electricity supplied to customers from the SIWS.
5. Encourage the taking of measures to manage the amount of electricity used and when it is used.

1 Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 2.16.12 (online)

1.1 Purpose of this issues paper

To prepare for the review, the ERA has analysed market data, considered information provided in discussions with market participants, and collected evidence from past reviews of the market. This issues paper combines this analysis and outlines the ERA's initial observations of:

- how well the WEM is achieving its objectives
- what may be driving these market outcomes.

Information received during the consultation process will inform the ERA's preparation of the final report to the Minister for Energy.

1.2 Reporting context

In March 2019, the Minister for Energy announced the Government's Energy Transformation Strategy in response to the rapid and ongoing uptake in rooftop photovoltaic systems and an increase in the number of larger-scale wind and solar farms connecting to the electricity network.[2]

As part of the strategy, a whole of system plan and distributed energy resource roadmap will be prepared to complement the market and constrained network access reforms currently under way. The Energy Transformation Strategy is overseen by a Taskforce and supported by a dedicated implementation unit within Energy Policy WA (EPWA), a new energy sub-department within the Department of Mines, Industry Regulation and Safety.[3]

At the time of writing, the Energy Transformation Taskforce had released several papers providing information on aspects of the future market design and regulatory framework.[4] Further papers and detail on the design and operation of the future electricity market and network are expected. The ERA does not intend to investigate issues under the purview of the Taskforce, however it will look at areas that may be emerging gaps.

1.3 Scope and structure

This paper comprises two main components; a summary of the major market trends and features that the ERA has observed over the previous year in Section 2.1 and a summary of the WEM's effectiveness in meeting the market objectives in Section 2.2. This is followed by a discussion in Section 3 of market challenges that may not be addressed by the energy reform work currently underway. Detailed market observations are provided in Appendix 1.

This issues paper presents an opportunity to respond to the information presented and the conclusions drawn from it. The ERA encourages interested parties to make submissions during the consultation period, providing evidence or practical examples where possible.

2 Government of Western Australia Media Statements, 6 March 2019, *McGowan Government launches Energy Transformation Strategy* (online).

3 Government of Western Australia Hansard, 15 August 2019, *Energy Policy WA*, (online).

4 Energy Transformation Taskforce publications (online)

2. The state of the Wholesale Electricity Market

The following sections provides a summary of the operation of aspects of WEM operation, consistent with the ERA's monitoring and reporting requirements in the market rules.

2.1 Wholesale Electricity Market observations

Main points

- In 2018/19, the installed electricity generation capacity on household and business rooftops overtook the combined capacity of Synergy's coal generators.
- This has reduced the amount of electricity demand from the network, with the lowest level of customer demand since 2009/10. Mild weather and subdued economic activity also contributed to the low demand.
- This low demand, coupled with more low-cost wind generation entering the market in 2019, reduced average Wholesale Electricity Market prices in 2018/19.
- Ancillary service costs increased in absolute and per unit terms in 2018/19. Load following ancillary service costs in per unit terms have nearly doubled since 2015/16.
- Excess capacity in the market will fall with the retirement of Muja Power Station Stage C by 2024.

2.1.1 Electricity demand

Average, maximum and minimum demand during off-peak periods grew modestly from the start of the balancing market in 2012/13 until 2017/18, and then fell slightly in 2018/19.[5] The same demand measures for peak periods have been falling since 2015/16 (Figure 1).

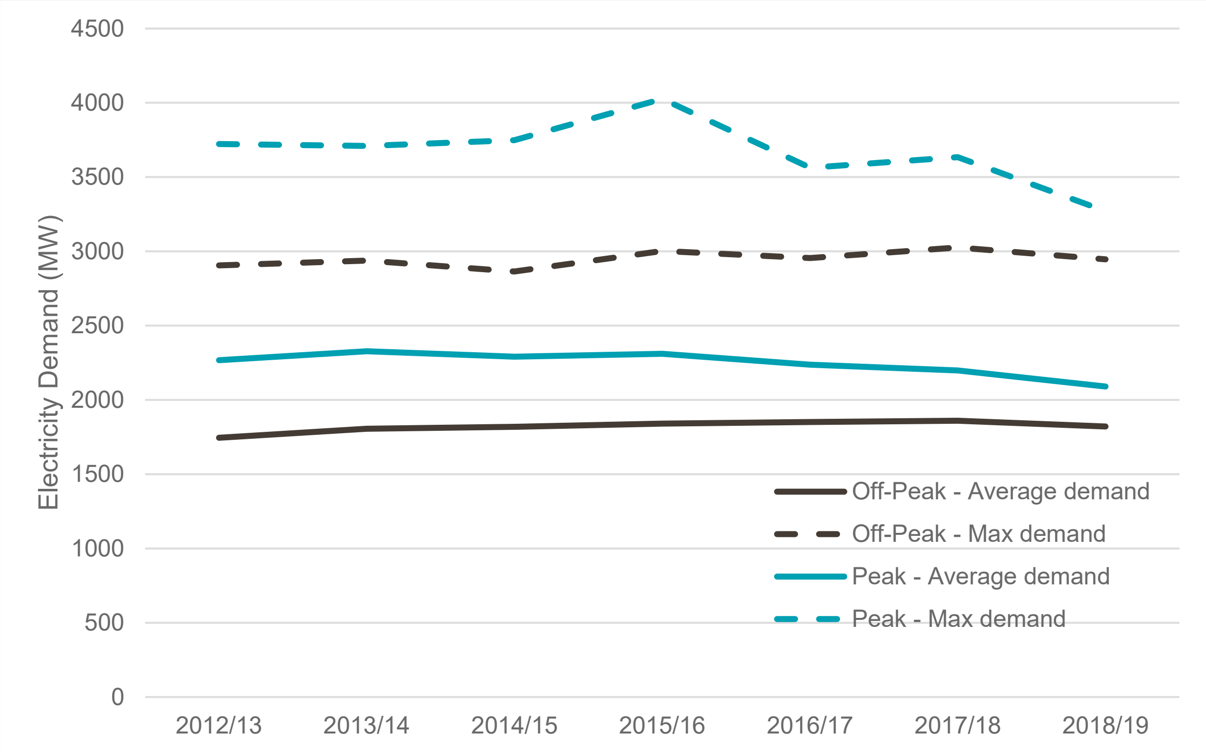
The greatest reductions in maximum demand occurred during weekday peak periods, indicating the effect of solar generation and possibly mild weather and reduced economic activity.[6] These effects are discussed further below. Weekends, especially Sundays, have lower demand than weekdays.

5 Peak periods are defined in the market rules as those between 8AM and 10PM for both weekdays and weekends. All other periods are off-peak.

6 From 2015/16 to 2017/18 financial years, growth in Western Australia's gross state product increased at a lower rate than long term averages and below the national gross domestic product. Gross state product data for 2018/19 was unavailable at time of writing, however, state final demand, growth in business investment and growth in private consumption were all below national averages.

ABS, 2018, *Australian National Accounts: State Accounts, 2017-18, Cat. No. 5220.0*, (online). WA Department of Treasury, 2019, *State/Domestic Final Demand, June 2019, Western Australian Economic Notes*, (online)

Figure 1: Average and maximum demand by financial year



Source: ERA analysis of AEMO data

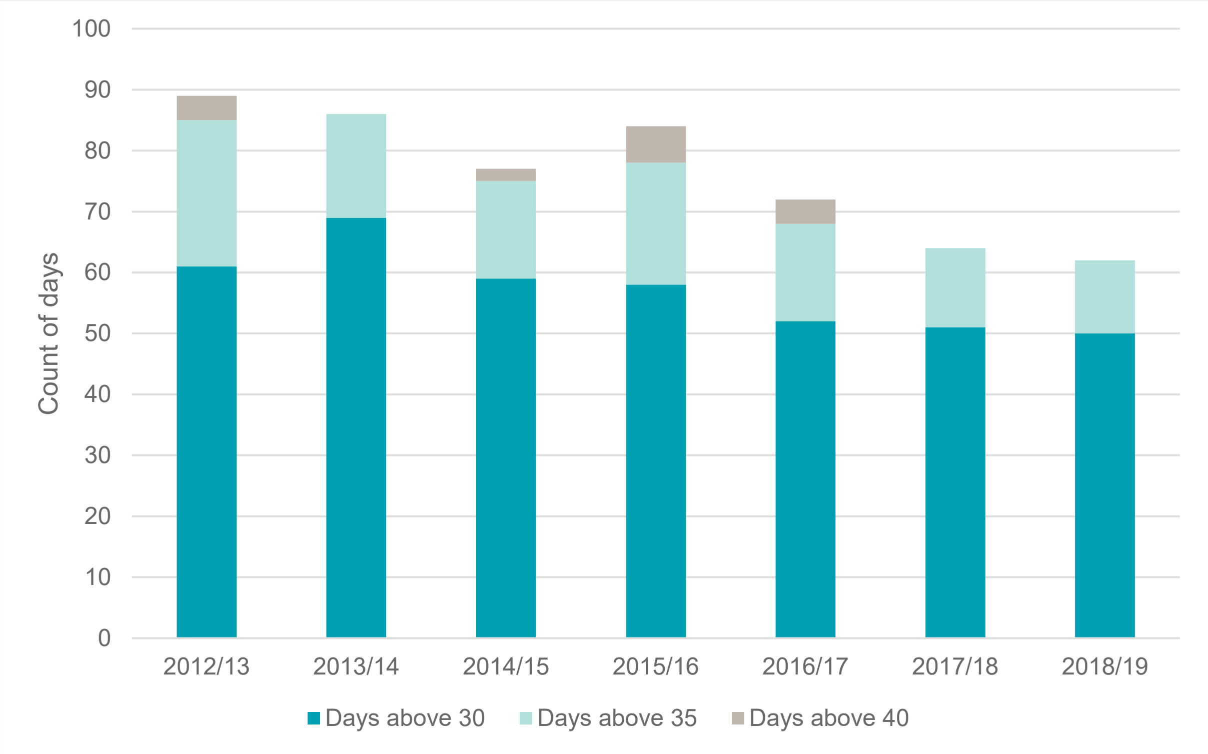
2.1.1.1 Ambient temperature

Ambient temperature affects the demand for electricity. Air conditioning, refrigeration, and heating and cooling loads are all sensitive to ambient temperature. With milder temperatures, the demand for electricity from temperature-sensitive loads decreases. Warm overnight and daytime temperatures in winter reduce residential heating loads. Cooler daytime temperatures reduce commercial and residential air conditioning loads.

Temperatures in Perth have been milder than normal for the last three summers.[7] Figure 2 shows the count of weekdays where the maximum temperature exceeded 30 degrees, 35 degrees and 40 degrees Celsius during the hot season. The data set has filtered out weekends, when commercial and industrial loads are generally lower or offline and demand is lower. This shows there were fewer weekdays of high temperature to drive up demand.

[7] Bureau of Meteorology, 2019, *Seasonal Climate Summary for Greater Perth – Product Code IDCKGC21LO*, (online). Ibid, 2018, (online). Ibid, 2017, (online).

Figure 2: Count of hot season weekday maximum temperatures for Perth Metro weather station



ERA analysis of Bureau of Meteorology data

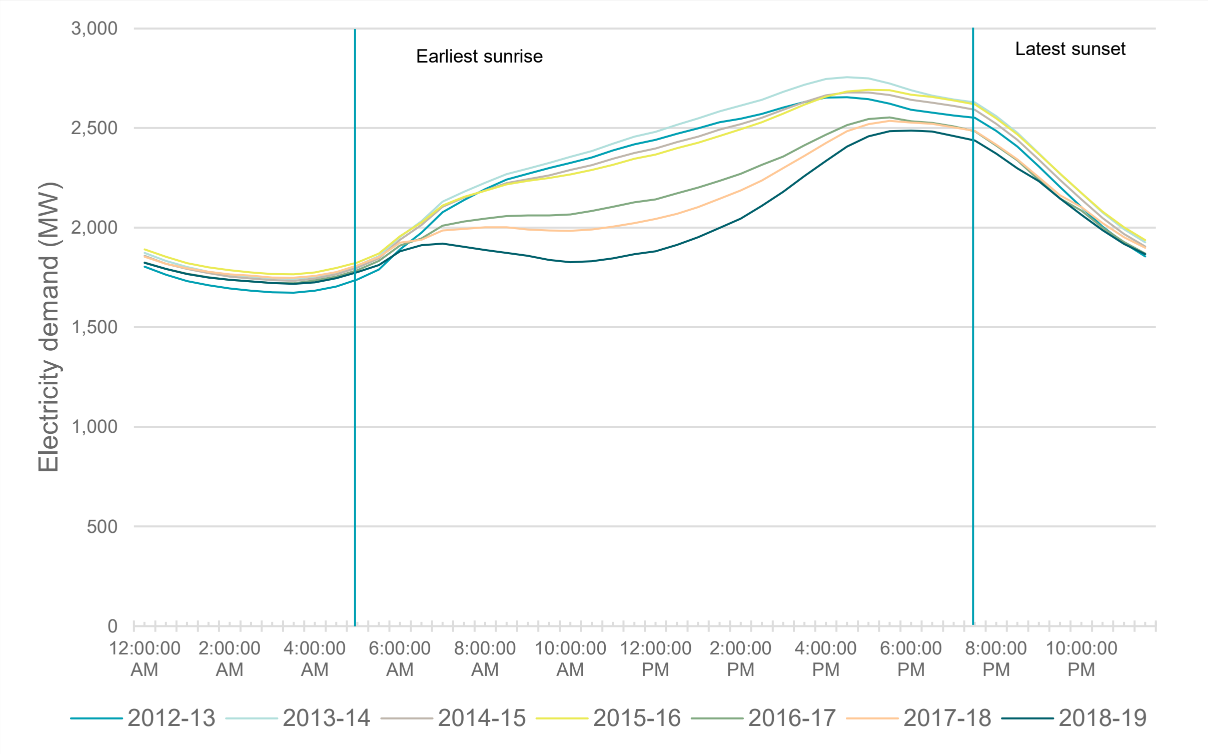
2.1.1.2 Load profile

The load profile, which shows how electricity is used over the day, has changed, as shown in Figure 3.[8] The weekday summer load profile has flattened and demand during the middle of the day has hollowed leading into an afternoon-evening peak. The weekend summer load profile is flat until mid-day with a daily low point around mid-morning which then also rises to an afternoon and evening peak.

The difference in demand in the load profile for the last three summers compared with other years persists after sunset, indicating that some of the demand reduction is weather-related.

8 The load profile is how much electricity is used by time of day for a given period.

Figure 3: Average summer load profile by year[9]



Source: ERA analysis AEMO and Geoscience Australia data

Rooftop photovoltaic (PV) output has reduced the whole WEM annual peak demand by an estimated 300MW for the 2018/19 capacity year.[10] Rooftop PV has also reduced localised network maximum demand in many parts of the network. These demand reductions should translate into less generation capacity required to supply demand in the WEM, and less localised network capacity being required in future, reducing capacity supply costs.

Output from rooftop PV generation has also changed the time of day at which the system peak occurs. The highest demands of the year now occur near sunset on very hot days. Supply from rooftop PV diminishes towards dusk as the available sunlight diminishes. Therefore, future rooftop PV installations will make minimal difference to overall demand at this near-sunset time. This implies that further generation and network capacity costs are unlikely to be avoided by installing additional rooftop PV.[11]

9 This load profile includes December, January, and February.

10 Annual (summer) peak market demand reduction from rooftop PV occurs due to it directly reducing demand around the original time of peak demand (without PV), and also due to the PV output suppressing demand further so that the market demand peak occurs later in the day (near sunset) when underlying demand (without rooftop PV) is normally lower than the original peak demand anyway. See AEMO (2019) Electricity Statement of Opportunities 2019, Perth, pp 42-47, (online).

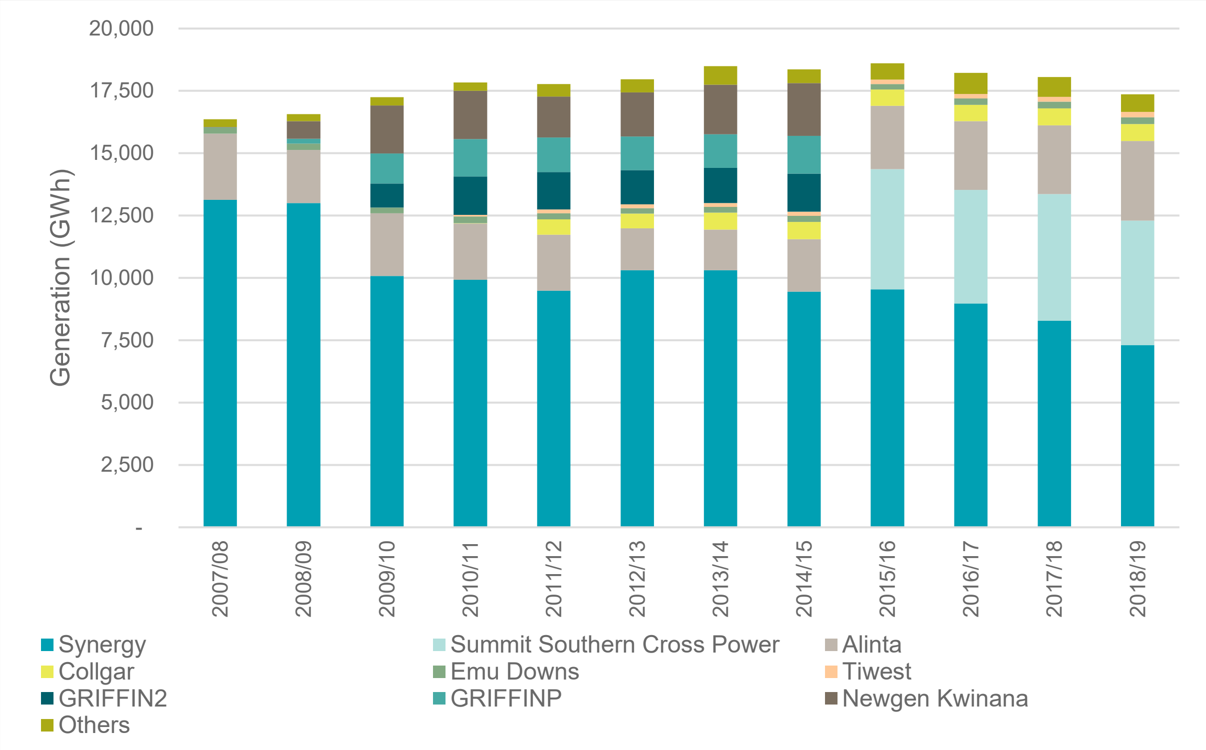
11 The exceptions to this, for network capacity, are locations in the network where the times of annual peak demand are still within relatively strong sunlight hours so that additional rooftop solar will reduce the local peak demand.

2.1.2 Balancing market and Short-Term Energy Market

2.1.2.1 Generation and market concentration indicators

Synergy was the largest generator in 2018/19 by capacity and electricity generated, followed by Summit Southern Cross Power and Alinta Energy. These three generators produced around 90 per cent of the electricity generated in the wholesale market (Figure 4).

Figure 4: Generation by market participant



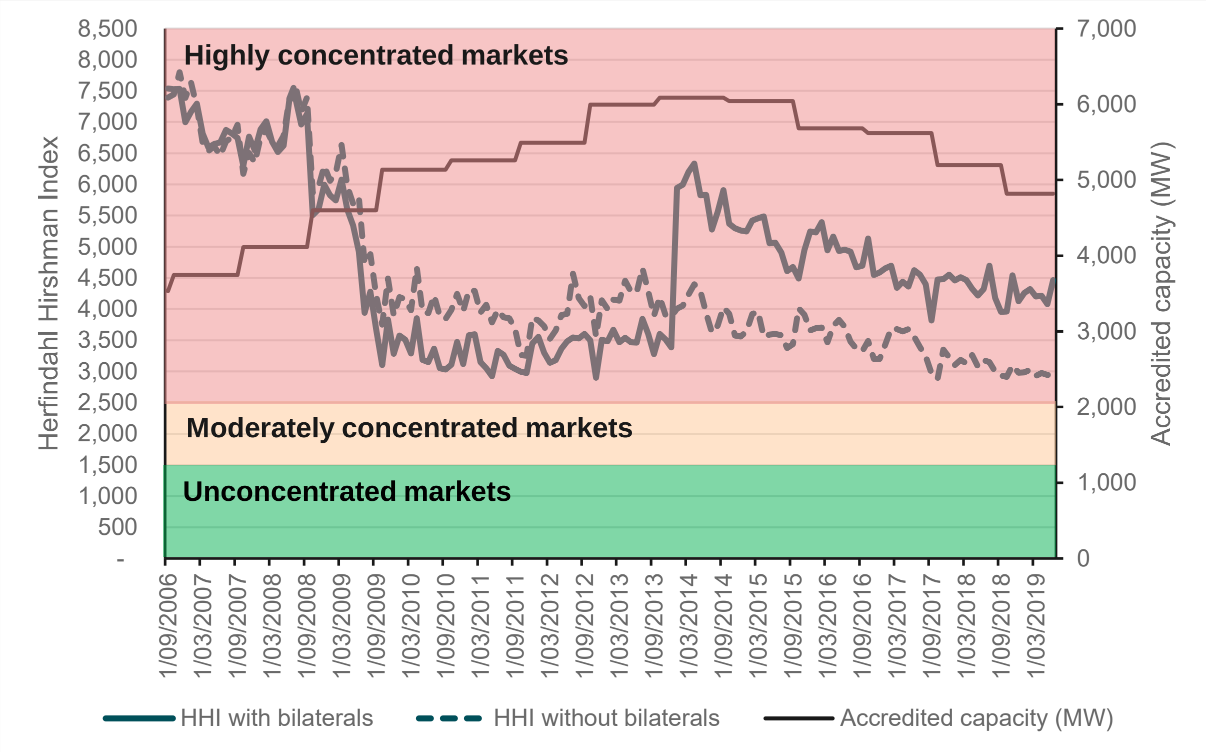
Source: ERA analysis AEMO data

Competition indicators for generation remained largely unchanged in 2018/19 and have not materially shifted in the last decade (Figure 5). While Synergy's market dominance (generation combined with bilateral purchases) has reduced from around 80 per cent in 2014/15 to around 70 per cent in 2018/19, the market concentration indicator for generation has plateaued and the WEM remains highly concentrated before and after accounting for bilateral contracts.[12]

The modest downward trend in the Hirfindahl Hirshman Index since Synergy was reaggregated with Verve Energy in January 2014 reflects change in market share between the three largest generators. The overall concentration index after accounting for bilateral contracts was lower prior to reaggregation as a number of bilateral contracts reallocated generation to other generators with a smaller wholesale market share.

12 Refer to Appendix 1 for additional information on the Herfindahl Hirschman Index.

Figure 5: Herfindahl Hirshman Index and accredited capacity



Source: ERA analysis of AEMO data

2.1.2.2 Market prices

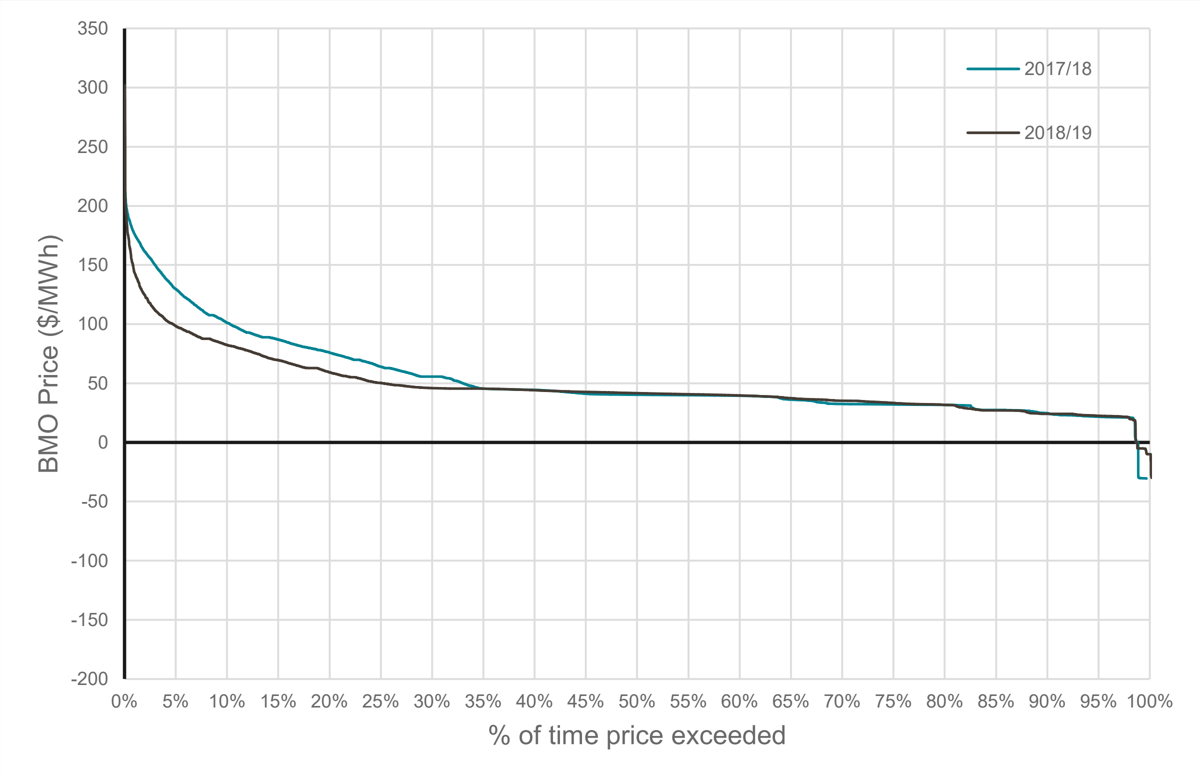
Average annual balancing prices were 13 per cent lower in 2018/19 than in 2017/18. Most of the price reduction was in the high ranges. Below $45/MWh, the price distribution between 2017/18 and 2018/19 was almost identical (Figure 6). Above this level there were fewer intervals with higher market clearing prices. For example, the market was settled:

- Above $50/MWh in 25 per cent of intervals in 2018/19, compared to 33 per cent of intervals in 2017/18.
- Above $100/MWh in just 5 per cent of intervals in 2018/19, compared to 10 per cent of intervals in 2017/18.

Above a price threshold of $40/MWh, Synergy set the price for 87 per cent of intervals in 2017/18 and 86 per cent of intervals in 2018/19. There has been negligible change in which generator sets the price in the market, and at what levels.

As stated in last year's report, the ERA has undertaken an investigation of Synergy's pricing behaviour and concluded that Synergy has market power and has been bidding wholesale energy into the market at values that are higher than the market rules permit.

Figure 6: Price distribution curves for 2017/18 and 2018/19



Source: ERA analysis AEMO data

The ERA has analysed pricing in peak periods and off-peak periods. Peak periods cover a wide range of conditions and demand periods.[13] The market definition of peak is from 8AM until 10PM each day. All other times are off-peak. Historically, demand and market prices are usually higher in peak periods than in off-peak periods. With generally lower consumption on weekends, the market definition of 'peak' has always been a somewhat arbitrary definition, but now lacks currency during weekdays as well due to the low middle-of-day demand.

Most of the price reduction observed in 2018/19 has occurred during the market-defined peak periods.

Weekday peak prices were 19 per cent lower and weekend peak prices were 15 per cent lower in 2018/19 than in 2017/18. Some of the lowest levels of demand and incidences of negative prices, which used to occur in off-peak periods, are now occurring during market-defined peak periods. These are predominantly on weekends when non-residential loads, such as those from small industrial businesses and offices, are lower because they are not operating or open.

The reduction in both maximum and average demand during peak periods referred to in section 2.1.1, has reduced prices. In 2018/19, average wholesale electricity prices during peak periods were the lowest since the start of the balancing market. Similar patterns are observed in the Short-Term Energy Market, albeit in a more muted form likely reflecting the different price-setting mechanism and smaller volumes in that market.

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[13] This paper includes two uses for the term 'peak'. Peak periods are defined in the market rules and cover daylight and evening hours between 8AM and 10PM. System, daily, weekly, seasonal or annual 'demand peaks' refers to the high points in consumption over the time period.

Off-peak balancing market price reductions are harder to discern than those observed during peak periods. While there were some brief periods of very high pricing during off-peak periods, the annual average off-peak prices have been similar for the last three years.

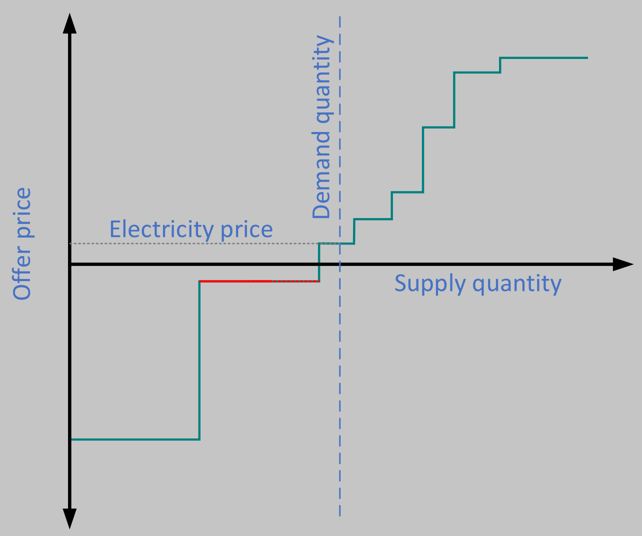
Price volatility

Balancing market pricing volatility has tended to increase, predominantly during peak periods. There are parts of the supply curve where prices escalate sharply. Greater variability in demand can result in material changes in cost.[14]

Rooftop PV generation changes the quantity of demand from the grid. What rooftop PV households and businesses do not consume themselves is exported into the grid and consumed at other premises. This reduces the quantity of generation served by the wholesale market. There is also variability in the supply of electricity from large-scale wind and solar farms. The combination of demand and supply variability contributes to more volatile market prices as outlined in Explanation Box 1.

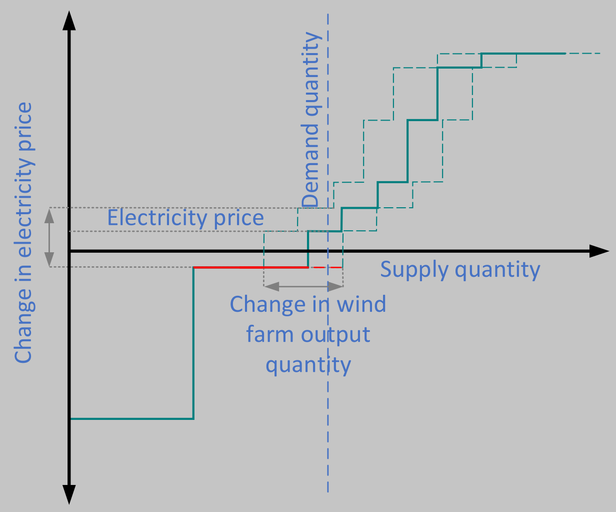
Explanation Box 1: How supply and demand volatility affect price

Offers into the electricity market comprise a price quantity pair. The diagram shows a supply curve with quantity plotted on the x axis and price on the y axis. The price for electricity will depend on where quantity of demand intersects the supply curve, indicated by the vertical line.



Intermittent generators such as wind and utility-scale solar farms produce a variable quantity depending on weather conditions. Variable generator output, shown by the red step in the figure above, will alter the shape of the offer curve. For a given demand quantity, if a wind farm increases output it will shift the curve to the right making electricity cheaper. If it reduces output, the curve will shift to the left making electricity more expensive.

14 Pricing volatility over time is shown in charts Figure A 1and Figure A 2 in Appendix 1.



Rooftop PV output has a similar effect, but on the quantity of demand to be met through the WEM. Lower solar output shifts the demand quantity intersection point to the right making electricity more expensive, and to the left for higher solar output making it cheaper.

Increasing variability in generation supply is likely to continue as large-scale intermittent generators continue to connect to the network and rooftop PV installation grows. More than 650MW of new nameplate capacity large-scale wind and solar has already connected to the network in 2019 or will connect in 2020 (refer to section 2.1.5). Customers are continuing to install approximately 150 to 200MW of rooftop PV each year.

By late 2020, approximately 1200MW of large-scale solar and wind generation will be operating on the network.[15] In addition, and based on current connection rates, around 1300MW of rooftop PV is also projected to have been installed. At times it will be challenging for AEMO to manage the variability of this 2,500MW of intermittent generation and maintain system security and reliability. This will have implications for ancillary services requirements. These difficulties will persist for at least two more years before market reforms are implemented in 2022.[16]

2.1.3 Ancillary services

Ancillary services are required to support the transmission of electricity from generator to customer, and include services designed to help the system cope with a sudden loss of generation and demand, as well as normal load-following to balance supply and demand variability.

The cost of ancillary services in the WEM remained high in 2018/19, both in absolute terms and as a proportion of wholesale electricity prices (Figure 7). The per unit ancillary service costs were $5.95 per MWh in 2018/19, up from $5.80 per MWh in 2017/18 and nearly double the 2015/16 costs of $3.10 per MWh.

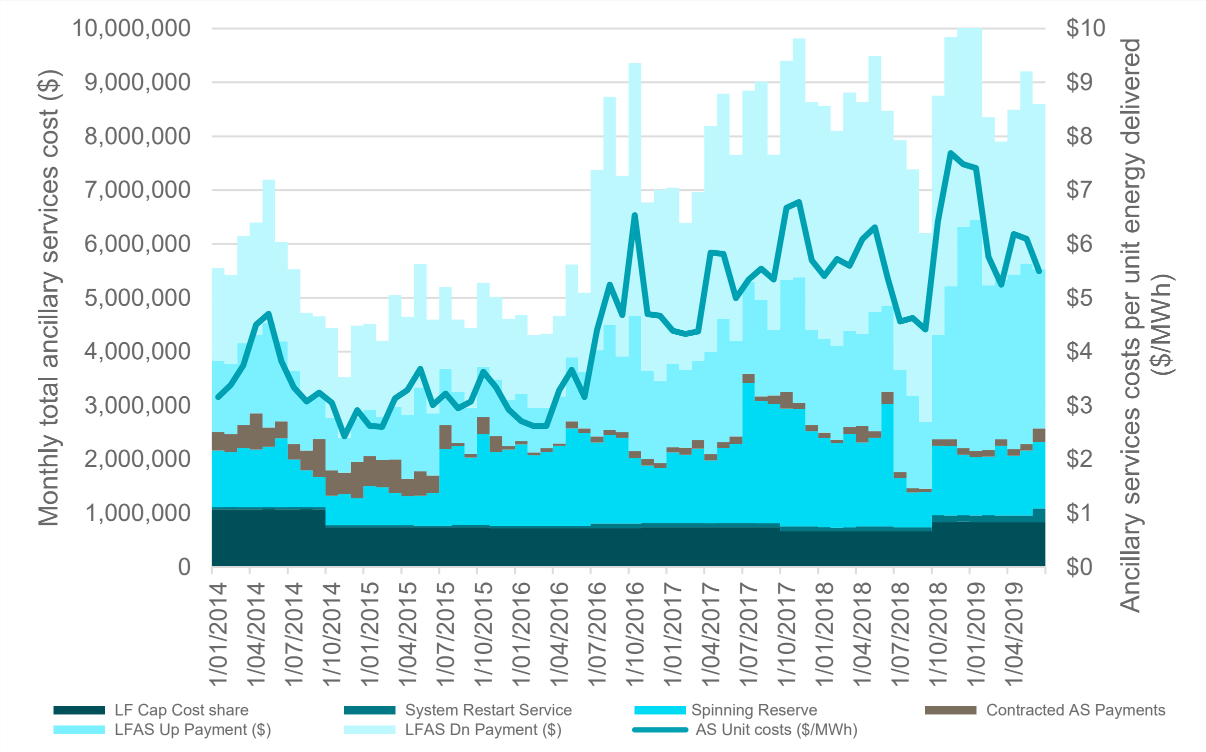
When total ancillary services costs are considered as a proportion of the notional cost of electricity generated, ancillary services costs comprise approximately 12 per cent of notional

[15] Sources: AEMO certification of reserve capacity (online), AEMO data and project websites

[16] See AEMO (2019) Electricity Statement of Opportunities 2019, Perth, p65, (online).

balancing market costs, up from 6 per cent in 2015/16. This increase has occurred despite no material increase in the ancillary service requirement.

Figure 7: Ancillary service costs by service in absolute and per unit terms.



Source: ERA analysis AEMO data

2.1.3.1 Load following

Load Following Ancillary Service (LFAS) is the largest element of the market's ancillary services costs. LFAS is the adjustment of generators' output in real time. This is to balance supply and demand in the WEM and maintain frequency variations within prescribed limits to protect power system security.[17]

Alinta began to participate in the LFAS market in the latter half of 2018/19.[18] An increase in the number of participants providing LFAS services would normally increase the competitive tension and driving lower prices. However, LFAS quantities bid into the market by third parties (other than Synergy) does not reach the total quantity required. Synergy provides the shortfall and continues to set load following prices in nearly all intervals.

While prices for individual services have changed, the overall cost of load following has barely moved with all LFAS prices converging on a single price.[19] The net effect has been that reductions in some service prices have offset increases in others with no discernible net change in the overall cost of LFAS. The reasons for this are unclear and the ERA will investigate this further during its review.

17 Rule Change Panel 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 3.9.1 (online)

18 Load following ancillary service (LFAS) is used to continuously balance supply and demand. LFAS accounts for the difference between scheduled energy (what has been dispatched), actual load, and intermittent generation. LFAS Up requires the provision of additional generation to maintain power quality (frequency) in real-time and LFAS Down requires the reduction in generation to maintain power quality.

19 Refer to Figure A 12 and associated text in Appendix 1.

While the LFAS requirement is ultimately driven by variability, load following quantities remained unchanged throughout 2018/19 and the same as in previous years. Aside from sporadic events where system management has activated backup, or reserve, LFAS quantities, the market did not procure more LFAS in response to the increase in intermittent generation. Consequently, the cost of LFAS observed during 2018/19 is separate from the increase in intermittent generation.

During 2019, AEMO concluded it needed additional LFAS to manage power system security.[20] Collectively, intermittent generation capacity is around two-fifths of the 2018/19 summer maximum demand. Most of this capacity is weather-dependent.[21] The output can change with time of day, solar irradiance and degree of cloud cover for solar generation, and with location and weather patterns for wind generation.

The output variability from rooftop PV, and utility-scale solar and wind farms, poses challenges to maintain the balance between supply and demand and keep the supply frequency within prescribed limits. As with all generators, unexpected output shortfalls must be covered by other generators. Consequently, AEMO has recently opted to increase the LFAS requirement between 5:30AM and 7:30PM and reduce the requirement at other times. However, this change did not take effect during the study period.[22] The growing output variability is expected to increase the future need for LFAS with AEMO anticipating additional increases to load following quantities.[23, 24]

2.1.4 Bilateral trades

Retailers manage the risk of price volatility through hedging arrangements. These can take the form of financial products as in the National Electricity Market, long-term offtake purchases or short-term supply arrangements. Hedging arrangements shield generators from low prices and limit retailers' exposure to high prices.

In the WEM, self-generation and bilateral supply contracts are the main hedging mechanisms. Market participants with more generation than they need to meet their customers' demand can on-sell this surplus to third parties. Regulations require Synergy to make hedging products available in the WEM via the standard product mechanism.[25] However, the suitability of this requirement as a hedging mechanism is limited and trades in such products have been thin and sporadic.[26]

The ERA regularly reviews the regulatory scheme that was set up to manage possible conflicts when retailer Synergy was merged with generator Verve Energy in 2014. Recently, the

20 AEMO, 2019, *Ancillary Services Report for the WEM 2019*, (online)

21 The exception is biomass. Biomass generation is generally not weather dependent (with the exception of anaerobic digesters where the reaction rates are sensitive to ambient temperatures. Landfill gas projects have large, in-situ digesters (landfill cells) in which ground temperature changes lag ambient air temperatures. They are non-scheduled as the gas cannot be readily stored or pressurised.

22 AEMO has changed the quantity of LFAS_UP and LFAS_DOWN procured increasing the quantity to 85MW from 5:30AM to 7:30PM and down to 50MW at other times, from 72MW (at all times) previously. AEMO, 2019, *Ancillary Services Report for the WEM 2019*, P. 16. (online). This changed requirement commenced on 28 August 2019.

23 AEMO, 2019, *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS*, P. 14. (online)

24 Ernst and Young, 2019, *Ancillary services parameter review 2019 methodology and assumptions report*, P. 11. (online)

25 Electricity Corporations (Electricity Generation and Retail Corporation) Regulations 2013, (online)

26 ERA, 2017, *Report to the Minister on the effectiveness of the Electricity Generation and Retail Corporation Regulatory Scheme 2017*, (online)

Minister for Energy endorsed some of the ERA's recommendations to improve the scheme.[27] For 2020, the buy-sell spread for Synergy's standard products will be reduced from 20 per cent to 15 per cent. A lower spread forces greater pricing discipline on Synergy, this may result in standard products becoming more attractive as hedging instruments. After this one-year trial, the spread will revert to 20 per cent.

The directions report outlining the proposed changes also indicated that Synergy would be required to publish the transfer pricing mechanism and any subsequent amendments.[28] Other reforms proposed by the ERA to improve the transparency of Synergy's financial reporting have not been adopted.[29]

2.1.5 Market capacity

Badgingarra Wind Farm (130MW) commenced operation in the first quarter of 2019. Badgingarra is the first generator to connect under the Generator Interim Access arrangement, which allows new generators to connect to the network but with the possibility that their output may be constrained to protect system security. Yandin and Warradarge wind farms are scheduled to be fully commissioned and operational in 2020, adding 394 MW of nameplate capacity to the WEM.[30] Merredin Solar (100MW) and Greenough River solar stage 2 (30MW) are also scheduled to be completed in early 2020.[31]

In August 2019, the Energy Minister announced that Muja Power Station Unit 5 would be retired by 1 October 2022, followed by Unit 6 by 1 October 2024. This will remove 392MW in combined accredited capacity from the market. Yandin, Warradarge and Badgingarra wind farms, plus Merredin and Greenough River stage 2 solar farms, collectively total around 145 MW of certified capacity.[32]

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27 Two Ministerial Orders were gazetted on 23 Jul and require Synergy to publish updated foundation transfer pricing mechanism and to reduce the buy/sell standard product spread in 2020.

28 Public Utilities Office, 2018, *Improving the effectiveness of the Electricity Generation and Retail Corporation Regulatory Scheme*, (online)

29 Recommendations from the 2017 review that were not adopted include:

- Relaxing Synergy's wholesale credit requirements so they are commensurate with the commercial risk of counterparty default,
- Making the force majeure suspension clause in standard product contracts less conservative and more symmetrical to recognise the relative risk of non-supply to both parties
- Extending the non-discrimination requirements of the EGRC scheme to the foundation transfer pricing mechanism
- Requiring Synergy to prepare and provide confidential segmented financial reports to the ERA in a format that is sufficiently transparent to identify anticompetitive behaviour. The format of the segmented financial reports should distinguish between revenues, costs and profits for:
    - gas and electricity activities in each business unit
    - contestable and non-contestable customers in the retail business unit.

Additional information is available in ERA (2019) Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporation Regulatory Scheme 2017, ERA, Perth, online

30 Yandin and Warradarge wind farms will have 40.932MW and 36.124MW of certified capacity respectively. Badgingarra wind and solar farm has 36.428MW of certified capacity. AEMO Summary of certified reserve capacity for 2020-21 capacity year (online)

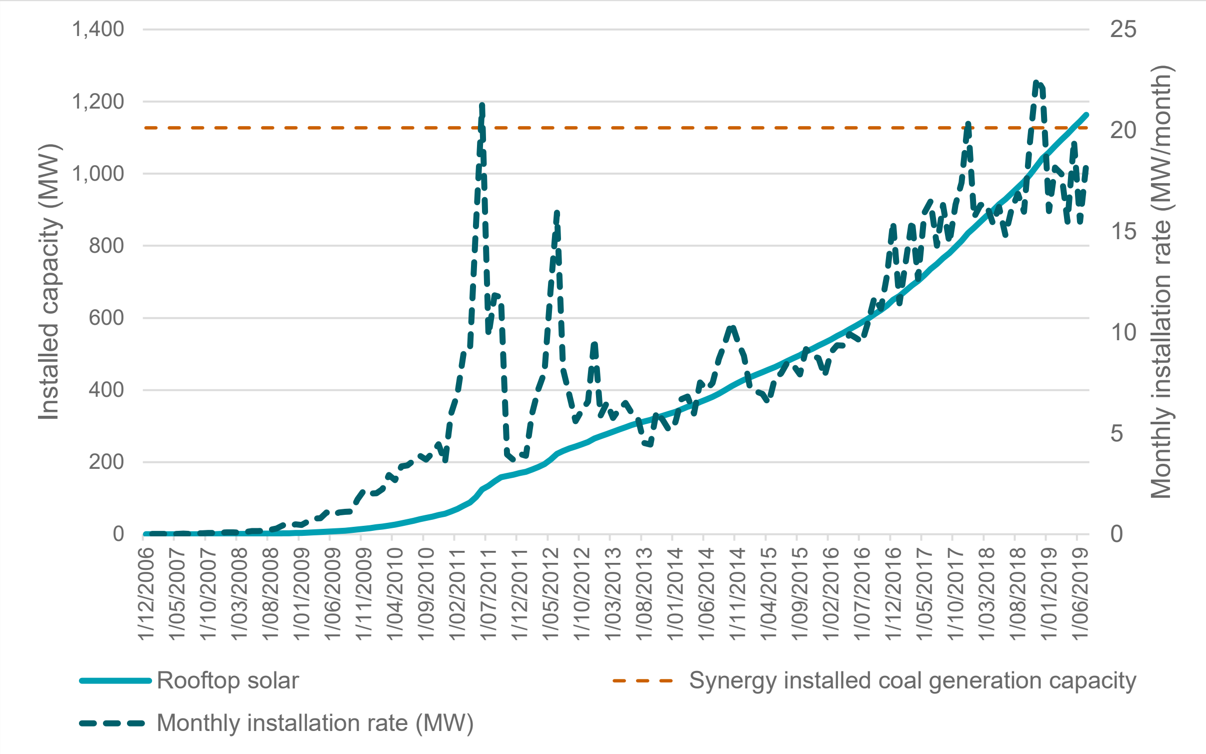
31 Merredin and Greenough River stage 2 solar farms will receive 22.5MW and 8.58MW of certified capacity respectively. AEMO Summary of certified reserve capacity for 2020-21 capacity year (online)

32 Sum of certified capacities in footnotes above.

The market now has 651MW of non-scheduled wind,[33] biomass and solar capacity coupled with 1,135MW of behind-the-meter private rooftop PV capacity across nearly 300,000 installations.[34]

The rooftop PV growth trend continued with 215MW of additional capacity installed in 2018/19, (Figure 8). In 2018/19, the total rooftop PV installed capacity in the SWIS exceeded the combined capacity of Synergy's coal-fired generators.

Figure 8: Rooftop PV installed capacity and monthly installation rate



Source: ERA analysis on AEMO and Clean Energy Regulator data

33 Nearly double the installed capacity of the 340MW Collie Power Station.

34 Nearly three and a half times the installed capacity of the Collie Power Station.

2.2 Is the Wholesale Electricity Market achieving its objectives?

Main points

- The ERA is concerned that the WEM is not meeting all of its objectives effectively, beyond supplying safe and reliable electricity.
- Prices have reduced over 2018/19, but this due to a combination of weather, flat economic conditions and lower demand, not an improvement in competition.
- A return to more typical economic activity and weather conditions could substantially increase wholesale energy and reserve capacity prices.
- Evening peak demand is encouraged by the absence of price signals that might guide consumers to change their energy use.
- Rooftop PV remains the preferred choice for households and small business customers seeking to reduce their electricity costs.
- Wholesale supply remains highly concentrated.
- The retirement of Muja Stage C presents an opportunity for new generators to enter the WEM but there are barriers to the entry of new technologies such as batteries.

2.2.1 Economically efficient, safe and reliable

The WEM has an objective to promote the economically efficient, safe and reliable production and supply of electricity and electricity-related services in the South West Interconnected System.[35]

The provision of electricity has been safe, and the market has achieved its reliability indicators.[36] The WEM has not experienced poor reliability and excess accredited capacity has contributed to supply security. Despite this there are material challenges to security and reliability. Market design and systems were not developed to accommodate the current quantity of intermittent generation. The substantial uptake of rooftop solar and the low cost of intermittent generation is simultaneously reducing demand, increasing variability in demand and supply, and reducing the quantity of scheduled generation available. The Government's reform process is making substantial changes to systems and practices to maintain system security.

2.2.2 Encouraging competition

The WEM has an objective to encourage competition among generators and retailers in the South West Interconnected System, including by facilitating the efficient entry of new competitors.[37]

35 Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 1.2.1 (a) (online)

36 AEMO, 2019, *Ancillary Services Report for the WEM 2019*, (online)

37 Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 1.2.1 (b) (online)

The market effectiveness review for 2017/18 found that the market objective of encouraging competition was not being met.[38] The market remains highly concentrated and the market concentration and competition indicators have not improved to any meaningful degree in the last decade. The top three generators supply around 90 per cent of the wholesale market demand. The ERA remains of the view that Synergy's market dominance impairs competition.

The reform process is working on changes to network access provisions that seek to enable more generators to connect to the network. However, while the connection and capacity certification processes are under active development, it may be difficult for investors to obtain project finance while the outcomes are unknown. The question is whether the opportunity presented with the retirement of Muja Power Station Stage C will reduce market concentration and improve competition.

2.2.3 Avoiding discrimination

The WEM has an objective to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or reduce overall greenhouse gas emissions.[39]

Currently, the WEM is facing discrimination against certain technologies such as batteries and demand side management. A return to more typical weather and economic activity may increase demand above what is anticipated. With the retirement of Muja Stage C, removing barriers to entry and enabling fair competition from emerging technologies is an important issue.

Batteries have no clear registration path into the electricity market. While the market operator has indicated that batteries can be registered as a generator, they may not be able to participate in a wider range of activities that could attract additional revenue streams. Participating in a broad range of activities, such as providing network control services, capacity and ancillary services, could make batteries a more attractive investment. The ERA considers that enabling batteries to participate competitively in the market is critical given the high, and increasing, cost of ancillary services.

Barriers (for example the relevant demand calculation method) also appear to prevent market participation from demand side management providers who have raised concerns in the Market Advisory Committee about whether the current framework appropriately recognises the quantity of capacity the resource can usefully provide. Previous changes to market rules have removed incentives for demand side management providers to participate in the market.

This discrimination arises from the market and technical rules, and regulatory framework not keeping pace with technological changes. This is likely to reduce over time as the market reforms are implemented.

2.2.4 Minimising the long-term cost of electricity supplied to customers

The WEM has an objective to minimise the long-term cost of electricity supplied to customers from the South West Interconnected System.[40]

[38] ERA, 2019, *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2018* PP. ii-iv (online)

[39] Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 1.2.1 (c) (online)

[40] Rule Change Panel, 2019, Wholesale Electricity Market Rules 1 October 2019, clause 1.2.1 (d) (online)

Prices in the WEM have reduced over 2018/19 in comparison with previous years. However, this cannot be attributed to improvements in the market's competitive rivalry or any improvements in the market's structure or regulation.

Instead, it appears that the uptake of solar, modest economic activity, and mild weather conditions are collectively supressing demand for electricity and so reducing prices. A return to more typical economic activity and weather conditions may substantially increase wholesale energy and reserve capacity prices due to increased demand, especially following the retirement of Muja Stage C generators.

2.2.5 Encouraging measures to manage when and how much electricity is used

The WEM has an objective to encourage the taking of measures to manage the amount of electricity used and when it is used.[41]

The time of day consumers choose to consume affects the generation, transmission and distribution infrastructure needed to supply them. Demand peaks occur for relatively small periods of time but can be very expensive to serve.

The system maximum demand occurs in extreme temperature conditions. This increases the need for more generation and network capacity. Because the extra capacity is only required for those transitory peak demand periods, it can be much cheaper to manage the amount of electricity used at these peak times instead of building additional capacity.

The WEM pricing of the individual reserve capacity requirement reflects this. The individual reserve capacity requirement is a calculation of retailers and direct purchasers' contribution to peak demand. These organisations are then required to purchase sufficient capacity credits to cover their contribution to peak demand. Among large consumers at least, the individual reserve capacity requirement is effective at inducing responses from large commercial and industrial electricity consumers to reduce their demand on expected high demand days to minimise their capacity cost exposure.[42]

The move from unconstrained network access to constrained network access recognises the inefficiency of building network assets to avoid network congestion that may occur for very limited periods. Managing demand as a way of reducing capital expenditure on supply capacity may be similarly efficient (and has been elsewhere) but has not received the same recognition or emphasis in the reforms to date. In the residential sector, there has been no structural change to the price signals that most customers receive, with the exception of the large increase in the supply charge in July 2017,[43] and only incremental year-on-year increase in volumetric or variable charges.

The tariffs that underpin retail electricity bills for households and small businesses are based on how much electricity is used, and so do not reflect the causes of the costs to supply electricity. This may have encouraged more air conditioner and rooftop PV installation than might have occurred if customer tariffs had also reflected the peak demand causing higher costs.

Air conditioners and rooftop PVs increase the peaky nature of the market's demand profile. This requires more generators and increased network capacity in areas where demand will

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41 Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 1.2.1 (e) (online)

42 AEMO, 2019, *2019 Electricity Statement of Opportunities*, P. 8. (online)

43 Western Australia, 2017, Government Gazette, No127, Western Australian Government Printer, Perth, pp 3424-3427, online

exceed existing capacity, such as new housing developments and infill. The highest demands occur for relatively small periods over the year, in more extreme weather. Air conditioning and rooftop PV also increases demand volatility in the electricity market, increasing the cost of already-expensive ancillary services provision. More load-following ancillary service capacity is required when demand is more variable.

The record low system demands occurring in the middle of the day due to rooftop PV are expected to cause system security issues in the future. This will probably result in extra costs to manage system security unless the demand during the middle of the day can be increased.

The flatter and less variable the system demand profile, the lower the costs of supply can be for wholesale energy, generation and network capacity, and ancillary services. This is because more energy can be supplied by lower- cost generators and existing network capacity.

There are ways to encourage a flatter demand profile. Many households and smaller customers have loads that can move. Use of appliances such as dishwashers, clothes dryers, washing machines, and pool pumps could be moved from the evening demand peaks to the middle of the day. Shifting load can reduce system security concerns arising from low demand at the same time help reduce annual peak demand and avoid associated infrastructure costs.

Questions

1. Do you agree with the ERA’s assessment of how the market is or is not meeting its objectives? Please explain your perspective using examples.
2. Are there other factors you think the ERA should consider when assessing whether the market is meeting its objectives? Please explain your perspective using examples.

3. Emerging challenges

This section discusses the main issues that are currently preventing the WEM from meeting its objectives and identifies which of these issues are already being addressed through the Government's market reform program.

In its 2018/19 review of the effectiveness of the WEM, the ERA will focus on two issues that do not appear to fall within the scope of reforms. These are discussed in section 3.2.

3.1 Issues addressed by the reform program

3.1.1 Economically efficient, safe and reliable

Although the WEM is effectively meeting its security and reliability objectives, this is becoming increasingly challenging (as noted in section 2.2). Increasing quantities of rooftop PV and large-scale wind and solar farms, all with weather-dependent intermittent output, can create wide swings in supply and demand that are difficult to manage in real time, particularly when low-cost thermal generation is too inflexible to quickly respond. The reform program has identified the security and reliability challenges in the electricity system and is planning mitigation measures to ensure the ongoing security and reliability of the electricity system. These mitigations include:

- Introducing constrained network access, so low cost renewable generation can continue to connect. However, in some areas of the network, generators' output may be constrained to protect network and system security.
- Changes to generator performance standards and the technical rules governing network participation and operation.
- Creating a distributed energy resources (DER) roadmap to guide the continued integration of distributed energy resources such as batteries, electric vehicles and rooftop PV.
- Identification and procurement of new ancillary services to better respond to greater supply and demand variability.
- Defining and implementing a new market dispatch IT system to co-optimise the supply of energy and essential system services in a constrained network.

Currently, system managers manually intervene in the dispatch of generators to maintain the security of the power system. This means that higher cost generators can get dispatched before lower cost generators, which is not economically efficient. AEMO is also limited by the administrative processes in place to procure ancillary services. The reform processes will resolve both issues by automating and co-optimising the dispatch of energy and ancillary services to take account of constraints or congestion on the network. This is intended to deliver the economically efficient procurement and dispatch of energy and ancillary services.

3.1.2 Encouraging competition

The introduction of constrained network access will enable more generators to connect, which may help mitigate the high level of market concentration in the WEM. Beyond this, the reform program has identified a market power workstream but detail of the work program is yet to emerge. Past ERA effectiveness reviews have identified matters of market power that stem from Synergy's wholesale market dominance.[44] The ERA maintains its view that the most effective means of addressing this market imbalance is to address Synergy's market power.

3.1.3 Encouraging measures to manage when and how much electricity is used

Installation of rooftop PV generation is continuing to substitute demand previously served by market generators and alter the system load profile. As discussed in section 2.1.1, the load profile is now characterised by low load in the middle of the day followed by an early evening peak. Battery storage and electric vehicle charging could ameliorate or exacerbate the amount of generation and network capacity required to cover the load profile in coming years.

The DER roadmap, to be delivered to government by the end of 2019, is intended to guide how distributed generation, such as rooftop PV, batteries and electric vehicles are integrated into the market in a manner that maintains system security. The DER roadmap may help address the WEM objective of managing the amount of energy used and when it is used, if it addresses the use of price signals with supporting customer education. Such price signals and education could influence the adoption of new technologies or encourage less costly consumption patterns.

3.2 The ERA's areas of focus

Main points

- The reform process is addressing many of the elements the ERA has raised in previous WEM reports.
- However, two areas do not appear to be within the reform scope:
  - Decisions made in the network can influence outcomes in the WEM. There is no coordinating mechanism to ensure costs are optimised across the whole system to minimise long-term costs to customers.
  - Once reform is implemented, an efficient rule change process is fundamental to ensure the WEM can continue to develop, particularly given the rate of technological innovation in the industry. There is no mechanism to ensure a rule change is developed and implemented to address identified market inefficiencies or emerging problems.

The ERA welcomes and supports the wide-ranging Energy Transformation Strategy that will address many of the matters raised in previous WEM effectiveness reviews. However, changes delivered by the reform may not be sufficient to ensure all market objectives are fully met. The ERA intends to focus this year's review on two areas the reform process does not appear to address. These are discussed below.

[44] ERA, 2019, *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2018* PP.10-11 (online)

3.2.1 Market cost optimisation

The whole of system plan, under development as part of the government's Energy Transformation Strategy, is intended to help guide economically efficient future investment and policy decisions through four possible market development scenarios. However, a significant challenge is to ensure network investment decisions and market costs are optimised across both the network and wholesale energy market.

Currently, network investment decisions and generator connections on the network can have consequences in the wholesale market. This is because decisions on network investment, system management and operation are often made in isolation from one another. Without overall co-ordination, generators and retailers, Western Power, AEMO, and EPWA may make decisions consistent with their own priorities and objectives that do not result in least-cost outcomes for the market as a whole. This can be illustrated by the following examples.

North Country larger contingency

The unexpected loss of a generator causes an imbalance between supply and demand that must be corrected quickly, or the system will be at risk of immediately disconnecting supply to some customers. Restoring the balance is managed through the spinning reserve ancillary service. Spinning reserve is generation capacity that can turn up, or contracted loads that can turn down or off, and so respond rapidly to stabilise the system and restore the supply-demand balance. Sufficient spinning reserve is procured to manage the largest outage contingency risk in the SWIS. Historically, Collie Power station has tended to set the spinning reserve requirement.[45]

In 2020, two new wind farms with total capacity of 390MW are expected to connect in the north of Western Power's network on the same 330kV line as an existing 342MW generator, NewGen Neerabup. This will create a much larger outage risk to the network than those existing and previously contemplated in the market rules. From next year, a network outage on the 330kV line from Northern Terminal to Three Springs Terminal could isolate the Warradarge and Yandin wind farms as well as Newgen Neerabup from the network. In a worst-case scenario, this could cause a loss-of-generation contingency up to 732MW, substantially larger than the contingency posed by loss of either Collie (320MW) or Newgen Neerabup (342MW) alone.[46]

Under the current market rules, where a contingency exceeds that of the largest generation unit, the cost will fall on the entities operating the largest generation units (Collie and Newgen Kwinana), not necessarily the entities causing the largest contingency (Western Power, Newgen Neerabup, Yandin, and Warradarge in this example).

AEMO and the Market Advisory Committee are considering how to address the risk posed by these new connections.[47] There are three options:

- Augment the network to avoid the larger contingency risk. This option is not being considered.

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45 Spinning reserve is operating online capacity (interruptible load or generation) that is able to rapidly contribute to the supply-demand balance if the largest capacity contingency trips off causing a shortfall and system frequency decline.

46 AEMO, 2019, Spinning Reserve Implications of Multiple Generators on a Single Transmission Line, presentation to the Market Advisory Committee, P. 2. (online)

47 Rule Change Panel, 2019, *Market Advisory Committee Meeting 29 July 2019 – Minutes*, P. 7. (online)

- Constrain the wind farms' output down to manage the risk.[48]
- Dispatch generators to provide the additional spinning reserve required to manage the risk.[49]

Each of the options would incur costs that would be borne by different parties. There is currently no market mechanism or entity responsible for evaluating these options to ensure that the optimum option is chosen and implemented.[50]

The Market Advisory Committee has discussed developing rule change proposals to manage the ancillary service requirements and cost allocation for this north country contingency.[51] This will ensure system security is maintained and costs are allocated appropriately. However, resolving how costs can be minimised across the network and wholesale market at the time the decision to connect new generators is being made may require a more comprehensive response.

Network outage planning and effects on market generators

Western Power plans network outages to manage its network effectively. At times, such outages can cause connected generators to be unable to supply – partially or fully – into the wholesale market. The market incurs a cost if more costly generation needs to be dispatched to cover the missing output.

There is currently no mechanism in place to ensure that network outage planning chooses the overall least cost plan accounting for costs to the network owner, wholesale market and customers directly or indirectly affected by the planned outage.

Management of network voltages

Higher rooftop PV generation output in a network location or area generally causes the voltages in the network to rise. Western Power must keep network voltages within prescribed limits at all times, or network and consumer equipment can be damaged.

If network voltage is still too high after Western Power has done all it can operationally to manage the network voltage, AEMO will then dispatch a market generator to assist Western Power with voltage management in that area.[52] This would generally require the generator to be dispatched out-of-merit, at a higher cost to the market.

The increasing take-up of rooftop PV systems is starting to require market generators to be run, at times, for voltage management, when their marginal costs are higher than the market price. When this happens and the generator loses money while running, then it receives a constrained-on payment to compensate for the revenue shortfall. The incidence of this is not material at present but could increase in future as rooftop PV take-up continues to grow.

48 The cost to constrain generation will likely be borne directly by the wind farm market participants through reduced revenue, and by consumers because less low-cost generation will be available.

49 This will not always be possible – i.e. if sufficient spinning reserve-capable generation cannot be online due to low demand and/or high output from low cost intermittent generation.

50 Ancillary services are being renamed essential system services in the new market.

51 Rule Change Panel, 2019, *Market Advisory Committee meeting - 29 July 2019 – Minutes*, PP. 2-7. (online) and *3 September 2019 – Minutes*, PP 7-9, (online) and 15 October 2019 meeting papers. *AEMO presentation*, PP. 80-92, (online)

52 Generators are often able to absorb reactive power (VArs) which helps to lower the voltage.

There are alternatives to running market generators in this mode. Western Power has primary responsibility for voltage control over its network, but will not have visibility of the market cost consequences of the different approaches it takes to network management.

Question

3. Is the objective of minimising costs to consumers materially compromised by a lack of whole-of-system coordination? What is the best way to ensure that such decisions are in the long-term interests of consumers and meet the market objectives?

3.2.2 The rule change process

Market rule changes are fundamental to ensure the WEM continues to meet its objectives, including continuing secure and reliable energy supplies, encouraging competition and minimising the long-term cost of electricity to consumers.

Many rule changes are required to implement the large-scale and wide-ranging reform program under way. Given the scale and timing of the rule changes required, the Minister for Energy will approve the repeal and replacement of relevant rules rather than proceeding through the standard rule change process.

Beyond the current reform program, due to end in 2022, the WEM will need to continually change, particularly as technological innovation is changing the industry. These market changes will require new rules or revisions to existing rules. The rule change process must be effective to ensure the market rules keep pace with the dynamic nature of the industry.

The ERA has identified two issues with the rule change process that may limit the ability of the WEM to respond to ongoing changes in the industry. Without an effective and efficient change process, the WEM may not be able to develop in a manner that continues to meet the WEM objectives.

3.2.2.1 Responsibility for market development rule changes

Market rule 2.5.1 states that “any person may make a Rule Change Proposal.” The exception is the Rule Change Panel itself, which can develop and submit a rule change only if the change is needed to correct a manifest error in the rules or if the change is minor or procedural in nature.

Market participants, the ERA, the Public Utilities Office (now EPWA) and AEMO have all developed and submitted rule change proposals over the last two years. Individual organisations have submitted rule change proposals in support of their market interests or legislative obligations. Therefore, rule change proposals have been somewhat ad hoc with no systematic program to ensure continuous and efficient market operation.

The ERA

The ERA is not a policy-maker. It provides secretariat support to the independent Rule Change Panel. To avoid conflicts of interest, the ERA has developed a position on when it is prepared to submit a rule change proposal. This position is contained in a public document, which states that the ERA will only initiate rule change proposals:[53]

- That are conducive or incidental to the ERA's functions:
  - For example, a rule change to address a process deficiency, such as is proposed in rule change RC_2018_05 ERA access to market information and short run marginal cost information for the investigation process.
- Where the rule change results from the ERA's periodic review functions:
  - For example, the ERA completed its review of the relevant level method for allocating capacity credits to intermittent generators at the end of March 2019 and is in the process of preparing a rule change proposal to give effect to its recommendations to change the relevant level method.

The ERA will not initiate rule change proposals to develop the market or set policy.

AEMO

The Minister for Energy has conferred a transitional function upon AEMO to prepare for wholesale electricity market and constrained network access reform.[54] This function expires on 1 October 2022. Beyond this, AEMO has an obligation "to contribute to the development and improve the effectiveness of the operation and administration of the WEM by developing rule change proposals; providing support and assistance to other parties to develop rule change proposals."[55]

The ERA and AEMO are both obliged to consult with the Market Advisory Committee before preparing and submitting a rule change proposal.[56] This gives the MAC the opportunity to provide advice, comment or objections to the intended rule change proposal. This helps ensure each organisation keeps within its remit when developing and submitting rule change proposals. The ERA and AEMO would be less likely to proceed with a proposed rule change if the MAC raised objections.

Energy Policy WA

EPWA could take on the role of improving market effectiveness, although this agency has no mandate or legislative responsibility for ongoing market development. Currently, EPWA is focussed on delivering the large-scale reform program over the next three years. Afterwards, EPWA may be able to focus on incremental market improvements as rule changes. However, EPWA may suffer from the perception of conflict due to the Government ownership of major assets in the energy industry.

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53 ERA, 2018, *Economic Regulation Authority Rule Change Proposals*, (online)

54 Rule Change Panel, 2019, *Wholesale Electricity Market Rules 1 October 2019*, clause 1.20, (online)

55 Ibid. clause 2.1A.2.(IA)

56 Ibid. clauses 2.5.1A (AEMO) and 2.5.1B (ERA)

Market participants

Developing and submitting a rule change proposal requires considerable care and attention to detail, technical knowledge of market operation and the likely effects of the rule change upon the market, and widespread consultation with market participants. Naturally, market participants will develop and submit rule change proposals only if the expected net benefit of the proposal to them outweighs the cost of time and resources to develop and submit the proposal.

Although different organisations are developing and submitting rule change proposals, no party is mandated to develop and submit a rule change proposal to address an identified, or emerging, market inefficiency. This is a gap in the governance structure that may limit how effectively the WEM develops post reform.

The Pilbara electricity reform process has already considered ongoing market development for the North West Interconnected System (NWIS). In a paper outlining the proposed regulatory framework for the NWIS, the Public Utilities Office (now EPWA), allocated a rules evolution function to the Rule Change Panel.[57] If implemented, the Rule Change Panel will be required to develop and submit rule change proposals that generally improve the operation, efficiency and transparency of the NWIS in line with the Pilbara electricity objective and in consultation with the NWIS Advisory Committee, the Pilbara equivalent to the MAC in the SWIS. The Rule Change Panel recommended that their adherence to the rule change process should be subject to external governance by the Minister for Energy.

Question

4. Do stakeholders share the ERA's concerns about rule changes to enable market development post reform? Should a single entity be given responsibility for ongoing market development? If so, which entity is best placed to have this responsibility and why? What governance arrangements should be placed on that entity?

3.2.2.2 Obligations to process rule changes in a timely manner

When the Rule Change Panel was established in 2017, there were 10 legacy rule change proposals inherited from the now-abolished Independent Market Operator. Since then there have been 16 new rule change proposals made, and one rejected. The Rule Change Panel cannot control how may rule change proposals it receives, when it receives them and the complexity of those proposals.

To manage and efficiently process rule change proposals, the Rule Change Panel has developed a prioritisation framework. The Rule Change Panel Support team consults with the MAC on the appropriate prioritisation for each rule change proposal. To progress a rule change proposal, the Rule Change Panel requires information from other sources, such as AEMO, Synergy or other market participants. If this information is not forthcoming in a timely manner, the Rule Change Panel cannot always progress the rule change proposal consistent with its priority ranking.

57 Public Utilities Office, 2019, *Regulatory frameworks for the Pilbara electricity networks: System operations arrangements*, P.13. (online)

Two instances provide examples where the MAC has identified a proposal as a high priority but there have been ongoing delays in the rule change process.[58] The timeliness of the rule change process was identified as a problem in the Rule Change Panel's annual stakeholder survey for the last two years: 50 per cent of survey respondents considered the timeliness of the rule change processes were poor or below expectations.[59] However, the trend is improving.

Although the prioritisation framework has been approved and applied by the MAC, it does not obligate AEMO, the ERA or any other market participant to provide input to the rule change process in a timely manner. A delay in progressing high priority rule changes can mean an identified inefficiency in the market persists and the market does not operate effectively.

Questions

5. Do stakeholders share the ERA's concerns about the rule change process? How could the rule change process be changed to ensure parties progress rule change proposals in line with priorities prescribed by the MAC and the Rule Change Panel?

[58] The rule changes are RC_2014_03 Administrative Improvements to the Outage Process, a legacy rule change and RC_2017_02 Implement of 30-Minute Balancing Gate Closure, submitted by Perth Energy.

[59] Rule Change Panel, 2019, *Stakeholder Satisfaction Survey Results, Market Advisory Committee 3 September 2019 meeting papers*, PP. 63,64,67 (online)

Appendix 1 Market Data

AEMO is responsible for collection and primary analysis of data to monitor the effectiveness of the market under clause 2.16 of the market rules. AEMO is required to compile specific data into a Market Surveillance Data Catalogue and provide that data to the ERA.[60] The market rules also set out certain analysis AEMO must undertake and provide to the ERA.[61]

The ERA is responsible for monitoring the effectiveness of the market in meeting the wholesale market objectives and must investigate any market behaviour that may have resulted in the market not functioning effectively. The Market Rules require the ERA to consider specific data and analysis as part of its monitoring of the effectiveness of the market.

The WEM Report for the Minister is required under clause 2.16.12 of the market rules to include a summary of this information and data as well as the ERA's assessment of the effectiveness of the market and the effectiveness of AEMO and System Management in carrying out their functions. This summary will be provided in the final report.

To inform submissions from interested parties in response to this discussion paper, the ERA has identified some preliminary market observations outlined below.

Balancing market

Figure A 1 and Figure A 2 below show the weekly average prices in the balancing market in both peak and off-peak intervals from market start in 2012/13. The maximum and minimum balancing prices and one standard deviation around the average are also displayed on the chart.

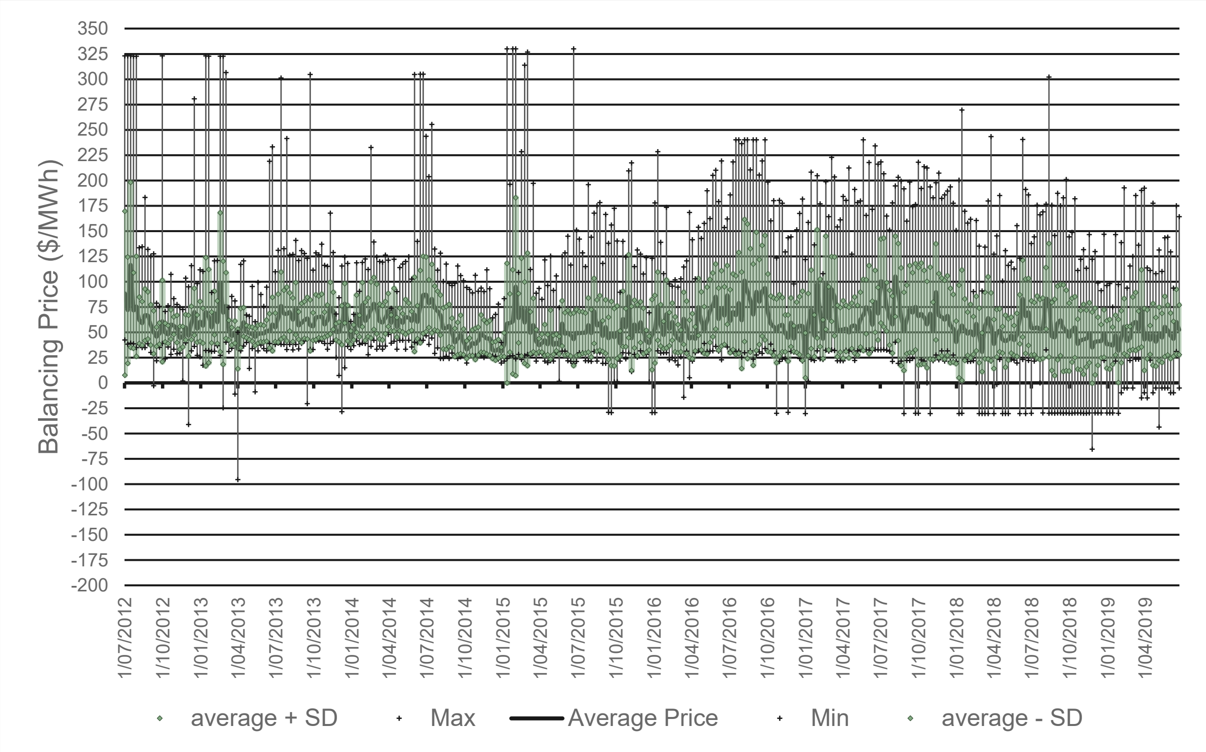
The average wholesale balancing price has decreased from $53.3/MWh in 2017/18 to $46.1/MWh in 2018/19 with prices in the final quarter of 2018 being 23 per cent lower than in the final quarter of 2017. This was primarily due to lower average demand, higher mid-merit generator availability and a milder average summer temperature. The average wholesale balancing price slightly increased through to June 2019 however was still seven per cent lower compared to the average balancing price in June 2018.

Wholesale electricity prices have remained volatile throughout 2018/19. There was an increased occurrence of high balancing prices in the WEM especially during off peak intervals in Q2 2019. The number of times the balancing price cleared at above $100/MWh and $150/MWh increased by 34 per cent and 170 per cent compared to Q1 2019. Of these prices above $150/MWh, 63 per cent of these intervals occurred during the morning peak period between 6:30 AM and 7:30 AM. These high balancing prices were primarily driven by participant bidding behaviour, with small, rapidly escalating price-quantity pair tranches (bids of less than 20 MW) in the Balancing Merit Order around the intersection point of the load forecast. When the load forecast intersects with these small Price-Quantity pair tranches, small variations in demand or fluctuations in non-scheduled generation can cause significant price spikes.

[60] Rule Change Panel, 2019, *Wholesale Electricity Market Rules*, clause 2.16.1, P. 74, (online)

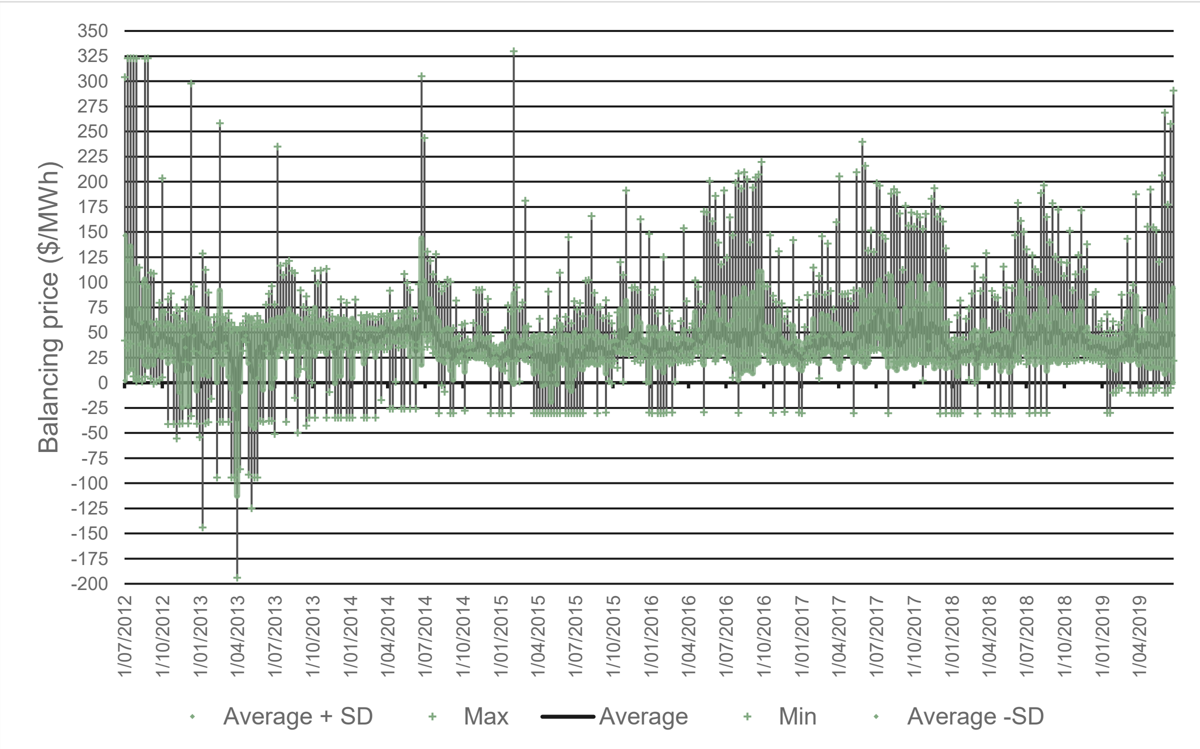
[61] Rule Change Panel, 2019, *Wholesale Electricity Market Rules*, clause 2.16.4, P.75, (online)

Figure A 1: Peak period weekly balancing market prices



Source: ERA analysis of AEMO data

Figure A 2: Off-peak period weekly balancing market prices

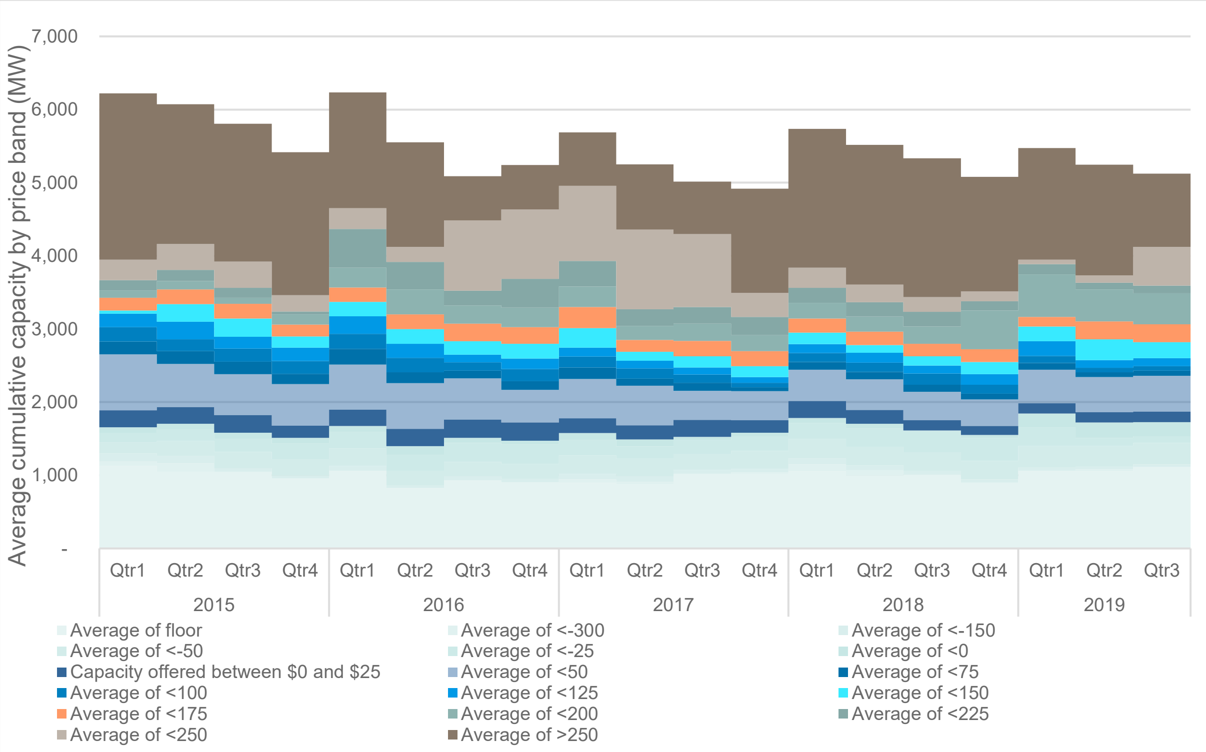


Source: ERA analysis of AEMO data

Figure A 3 shows the cumulative capacity offered above zero dollars per megawatt hour in price bands of $25. This shows the reduction in each capacity band below a price of $125 per MWh and an increase in capacity offered at higher prices between $150 and $225 per MWh.

While the change in the energy price limits (market caps) has played some role in generation offered below $250 per MWh,[62] less capacity is offered below $125. The average capacity offered between $0 and $125/MWh has reduced from an average of 1,360MW in 2015/16 to 860MW in the 2018/19.

Figure A 3: Average capacity offered by price band



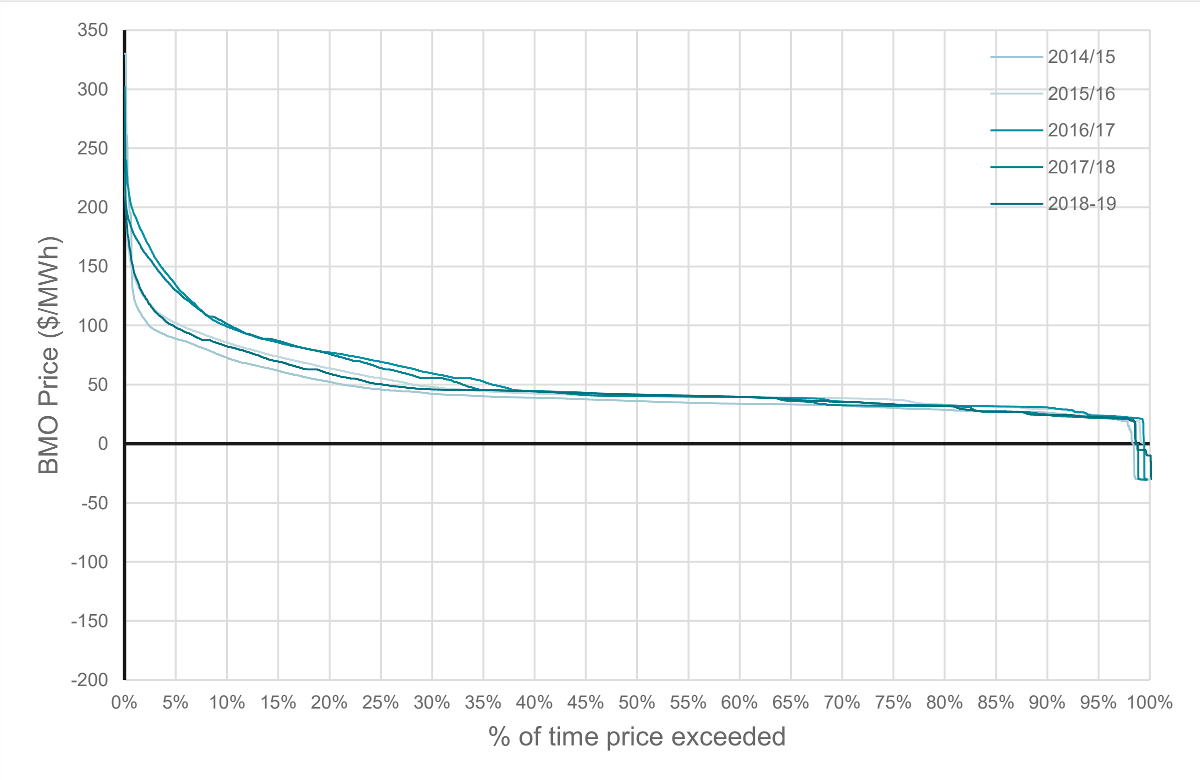
[62] The maximum non-liquid market cap (Maximum STEM price) reduced from $330/MWh to $253/MWh on July 1 2015. It further reduced to $240/MWh on 1 July 2016. On October 1 2017, it increased to $351 then reduced to $302/MWh on 1 July 2018.

Price duration curves

The price duration curve shows the changing demand distribution in the balancing market. Figure A 4 shows the amount of time (expressed as a percentage) that the balancing price exceeded a certain level from the start of the balancing market. For example, on the left-hand side of the chart, the balancing price exceeded maximum levels for only small percentages of time. On the extreme right-hand side of the chart, balancing prices exceeded the lowest balancing price most of the time. In the centre of the chart, balancing prices predominantly hover around $50/MWh.

The most notable feature has been the downward shift in pricing for the top twenty-five per cent of intervals in 2018-19 with prices more closely aligned with the 2015/16 distribution. This is different to the uplift in pricing for the top twenty-five per cent of intervals seen in 2016/17 and 2017/18 where the incidence of pricing above $50/MWh had been substantially higher than in previous years.

Figure A 4: Price duration curve 2014/15 to 2018/19

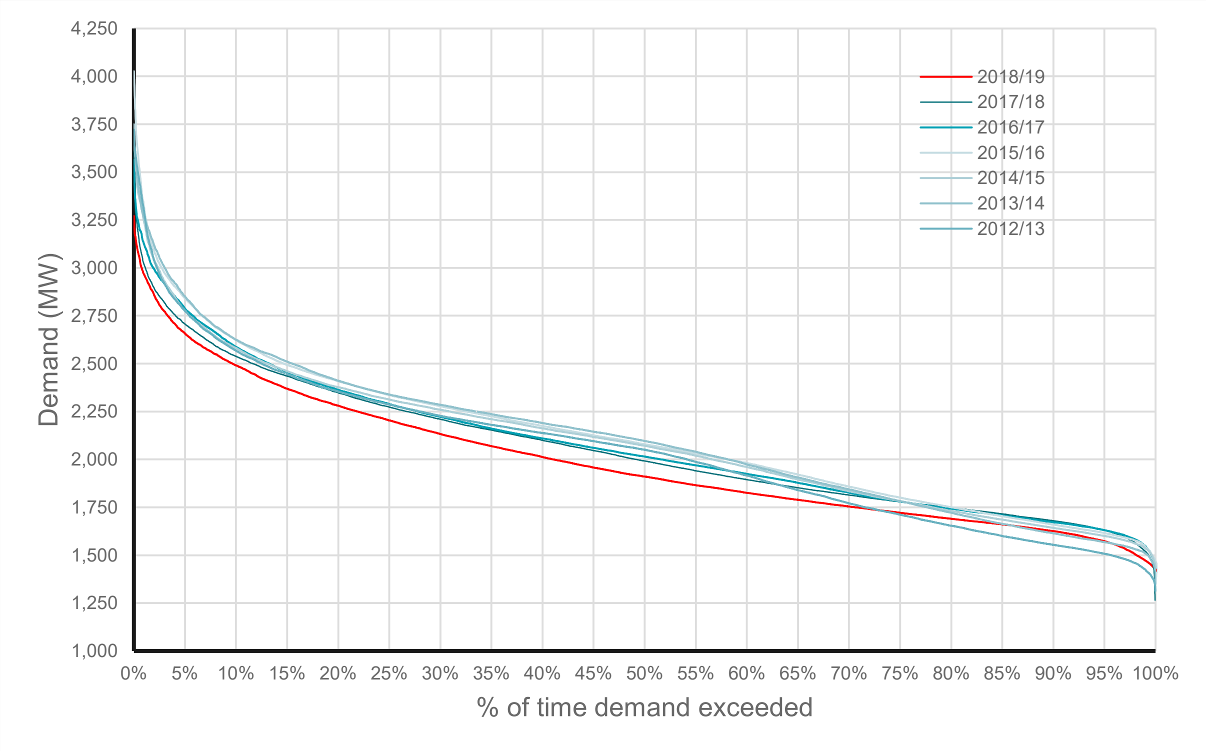


Source: ERA analysis of AEMO data

Load duration curve

Total demand has been falling progressively over recent years. The demand distribution is shown on a cumulative frequency plot termed a load duration curve. Figure A 5 shows the amount of time (expressed as a percentage) that demand exceeded a certain level for periods from 2012/13 to 2018/19. Figure A 5 shows the reduction in demand in 2018/19 where the curve sits below all other years since the start of the balancing market in July 2012. It is only the lowest 30 per cent of demand, below a threshold of 1,750MW, where the earliest two years of the balancing market experienced lower demand.

Figure A 5: Load duration curve 2012/13 to 2018/19

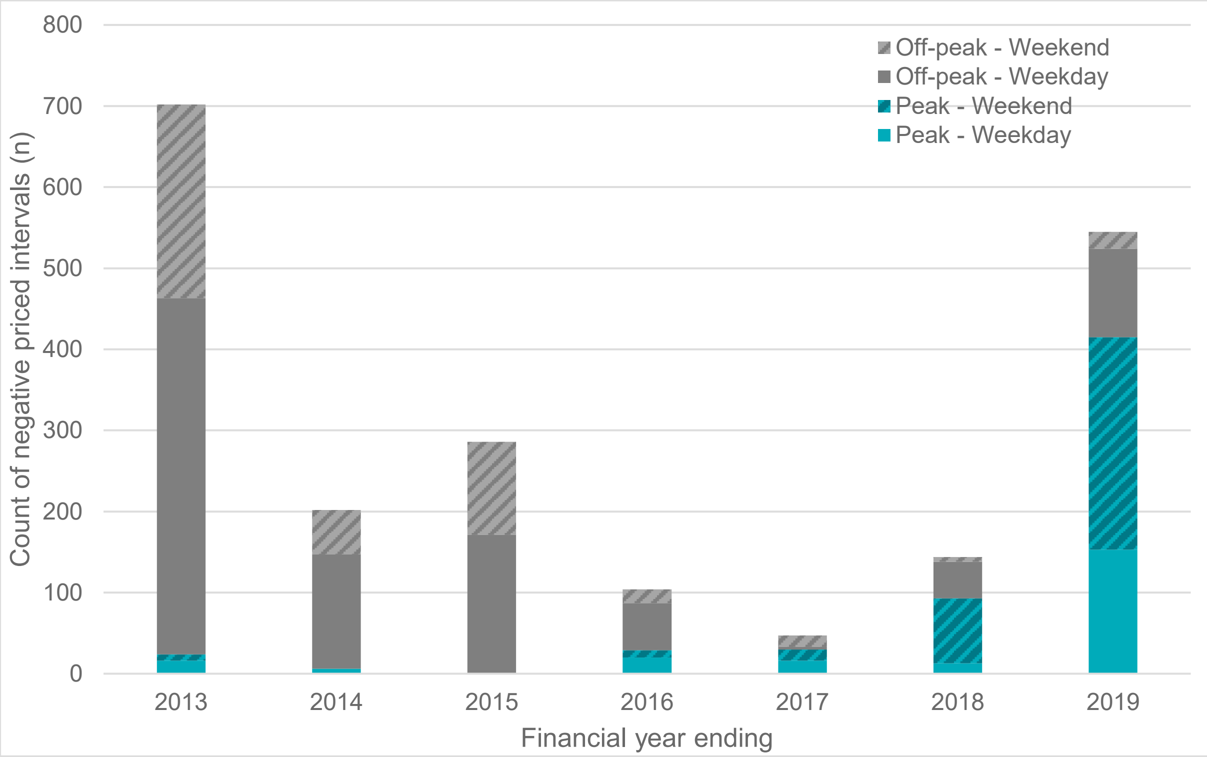


Source: ERA analysis of AEMO data

Incidence of negative pricing

The trend of increasing negatively priced intervals during peak hours times in the balancing market continued in 2018/19 (Figure A 6). The combination of rooftop PV, mild weather conditions and slow economic activity resulted in lower minimum demand. Most of these occurred on weekends. The number of negatively priced off-peak intervals increased in 2018/19 relative to 2017/18, possibly due to the commissioning of the Badgingarra wind farm increasing the quantity of low-cost generation in the balancing market.

Figure A 6: Incidence of peak and off-peak negative pricing



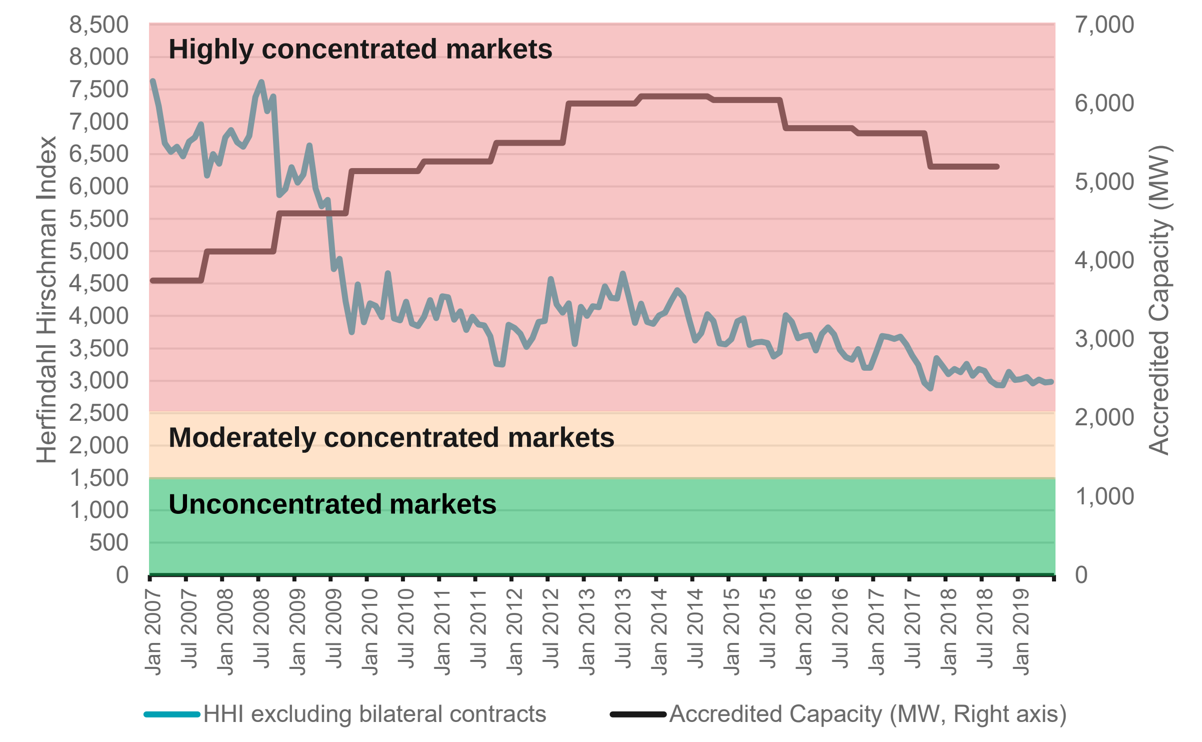
Source: ERA analysis of AEMO data

Market competition indicators

Despite lower balancing market prices, the market concentration indicators provides no evidence they are due to structural improvements in competition. The WEM remains highly concentrated as illustrated by the Herfindahl-Hirschman Index (HHI) shown in Figure A 7.[63] While the level of concentration has trended downwards since 2010 it remains within the highly concentrated area of the graph. Reductions in Synergy's output (the largest generator in the market) have been offset in the next two largest generators. The top three generators still collectively account for around 90 per cent of market supply. Output changes between these three mean the concentration index has barely moved.

63 The Herfindahl-Hirschman Index is a competition and market concentration indicator calculated by summing the squares of market participants' market shares. The results are weighted towards those with higher market share. Un-concentrated markets are those with an index below 1,500, moderately concentrated markets between 1,500 and 2,500 and highly concentrated above 2,500. US Dept. of Justice and Federal Trade Commission, 2010, *Horizontal Merger Guidelines*, PP. 18-19. (online)

Figure A 7: Herfindahl Hirschman Index and accredited capacity



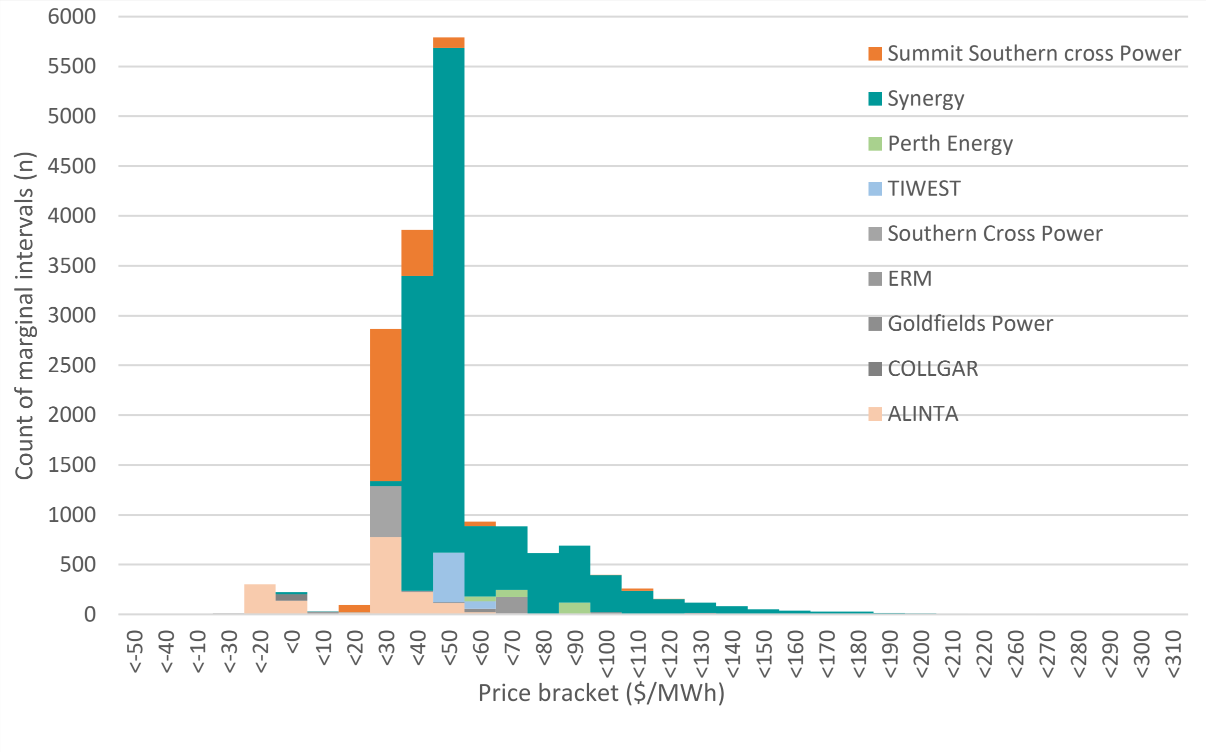
Source: ERA analysis of AEMO data

The HHI index is often used as an indicator of market competition. Less concentrated markets are considered more competitive when there is a greater number of participants with similar market shares.

In the WEM, the market is dominated by Synergy which owns or controls around 70 per cent of generation through bilateral supply arrangements, STEM purchases, and the dispatch of its own generators. The three largest generators, Synergy, Summit Southern Cross Power and Alinta collectively supply around 90 per cent of demand.

Most generators will operate in a narrow price range. Figure A 8 shows the 2018/19 pricing distribution and the parties setting prices which can help provide a nuanced interpretation of other competition indicators. In the WEM, Synergy still set the price for nearly 70 per cent of intervals, fewer intervals than in 2017/18. Below $30/MWh, Synergy set the price in just 2 per cent of intervals. Above $30/MWh, Synergy set the price 85 per cent of intervals – a modest reduction from 89.9 per cent of intervals in 2017/18 with the difference picked up by Summit Southern Cross Power. Below a price threshold of $30/MWh, there are more non-Synergy generators active. Where the price is set in this range more often, Synergy's more expensive generators run less frequently, and it risks losing market share.

Figure A 8: Who set the price and at what price 2018/19

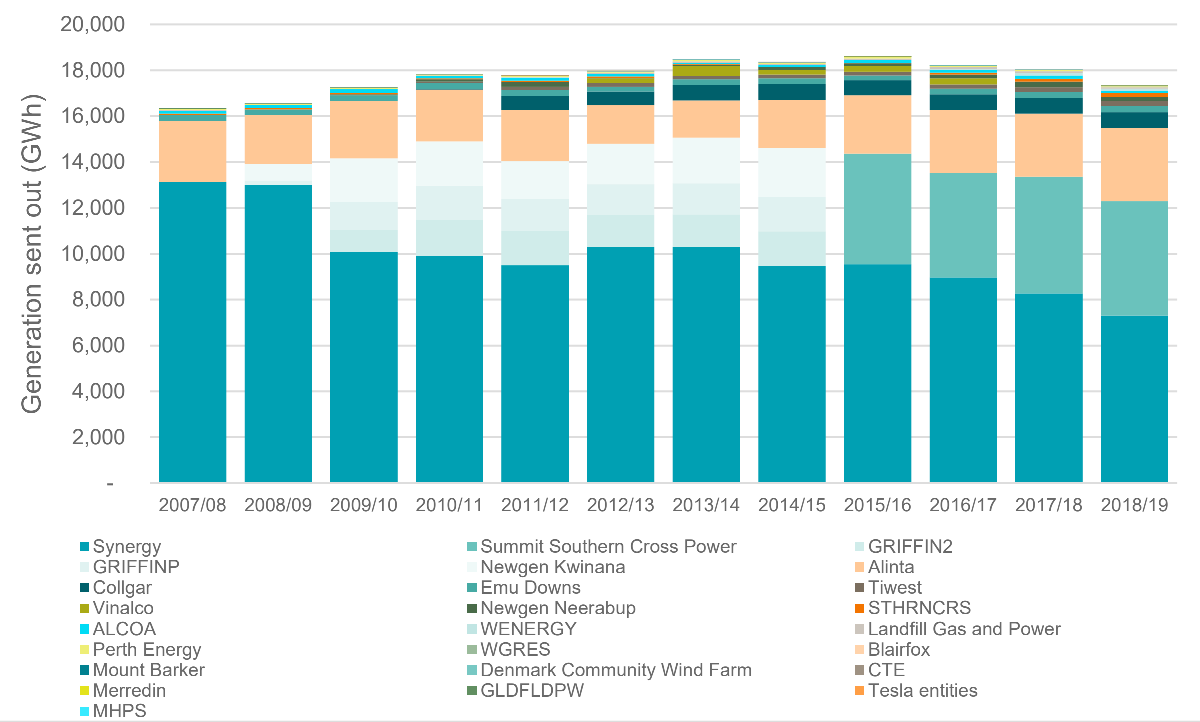


Source: ERA analysis of AEMO data

Generation sent out

Figure A 9 shows electricity generation sent out by market participants. Overall demand was lower in 2018/19 compared to 2017/18 and generation sent out was the lowest since the 2009/10 financial year. Synergy's share of generation sent out reduced further to 42 per cent in 2018/19 compared to 45 per cent in 2017/18. Alinta's generation output increased from 15 per cent to 18.5 per cent in 2018/19 whilst Summit Southern Cross Power generators' output was comparable to that in 2016/17 at around 29 per cent. The three largest generators Synergy, Summit Southern Cross Power and Alinta contribute around 90 per cent of generation.

Figure A 9: Generation sent out by market participant from 2007/08 to 2018/19

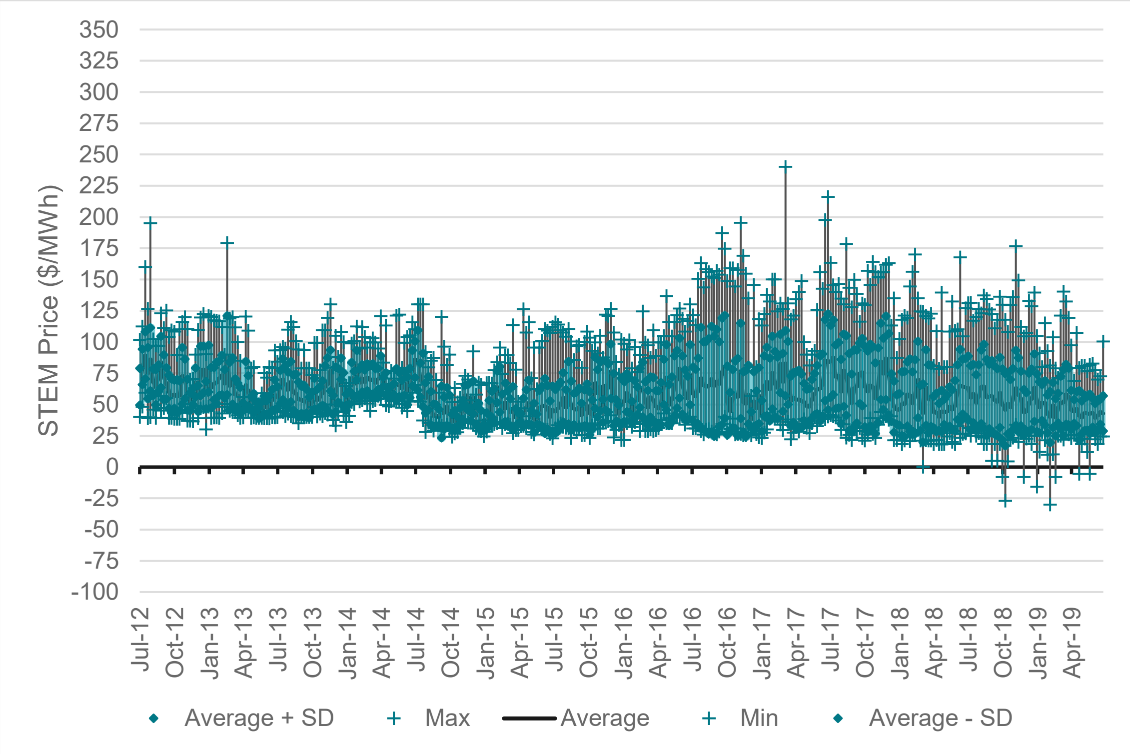


Source: ERA analysis of AEMO data

Short term energy market

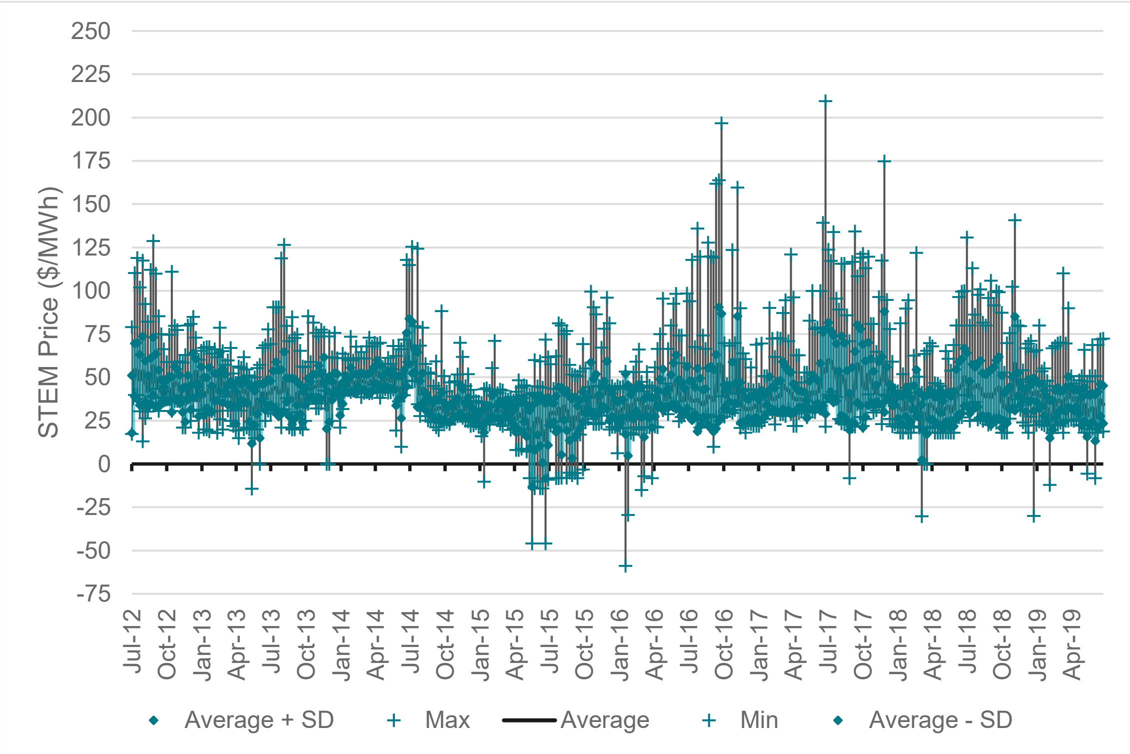
Figure A 10 and Figure A 11 show peak and off-peak weekly summary price data for the Short-Term Energy Market (STEM). The patterns show comparable trends to the balancing market with the total trading range elevated and negatively priced intervals. These trends are more muted in the STEM, possibly reflecting the smaller trading volumes and different price setting mechanism that has tended to result in more moderate outcomes than in the balancing market. Since the start of the balancing market, there had been no negative priced intervals in peak periods until the 2018/19 financial year.

Figure A 10: STEM weekly summary data – peak intervals



Source: ERA analysis of AEMO data

Figure A 11: STEM weekly summary data – off-peak intervals



Source: ERA analysis of AEMO data

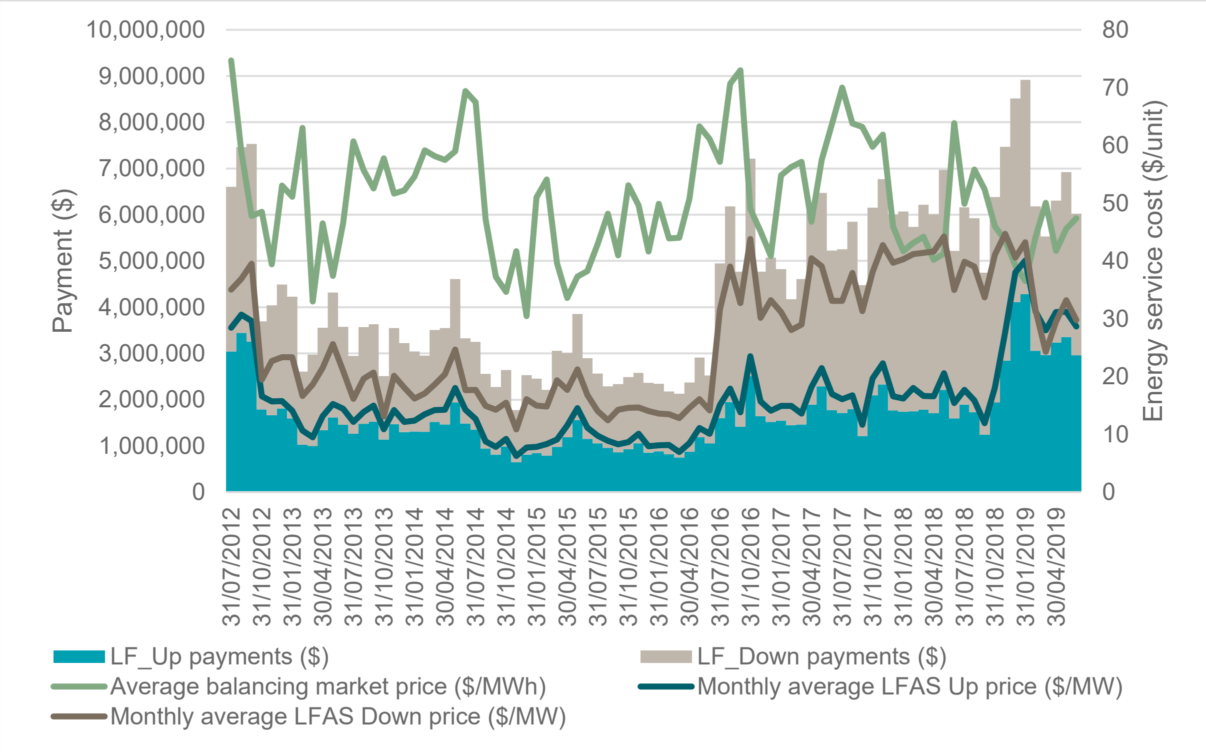
Ancillary services

The Load Following Ancillary Services (LFAS) market meets short-term supply and demand imbalances. There are just four participants cleared to participate in the LFAS Up and Down markets: Synergy, Newgen Power Kwinana, Tiwest Joint Venture and Alinta, with Synergy the pivotal supplier and Tiwest Joint Venture not participating. There has been limited competition in the LFAS market, and the competitive pressure anticipated to reduce prices in the market has failed to materialise. Instead, the market continues to be dominated by a single supplier, Synergy, which sets the price for all but a handful of intervals.

The LFAS requirement in 2018/19 was 72MW for both LFAS Up and LFAS Down. Collectively, the quantities provided by non-Synergy participants are insufficient to meet the 72MW and so Synergy is still required to provide LFAS. Even though Synergy's cleared quantities are minimal, it still sets the LFAS price in all but a handful of intervals as it remains a pivotal supplier.

The introduction of Alinta in the LFAS markets in early 2019 has reduced the price setting role of Synergy, mostly in the LFAS Down market during the middle of the day. In total, there were 142 intervals in which Synergy was not the price setter, with the price being set by Alinta during 125 of these intervals. Figure A 12 below shows the monthly LFAS payments.

Figure A 12: Ancillary services costs and proportion of ancillary service costs of balancing market prices

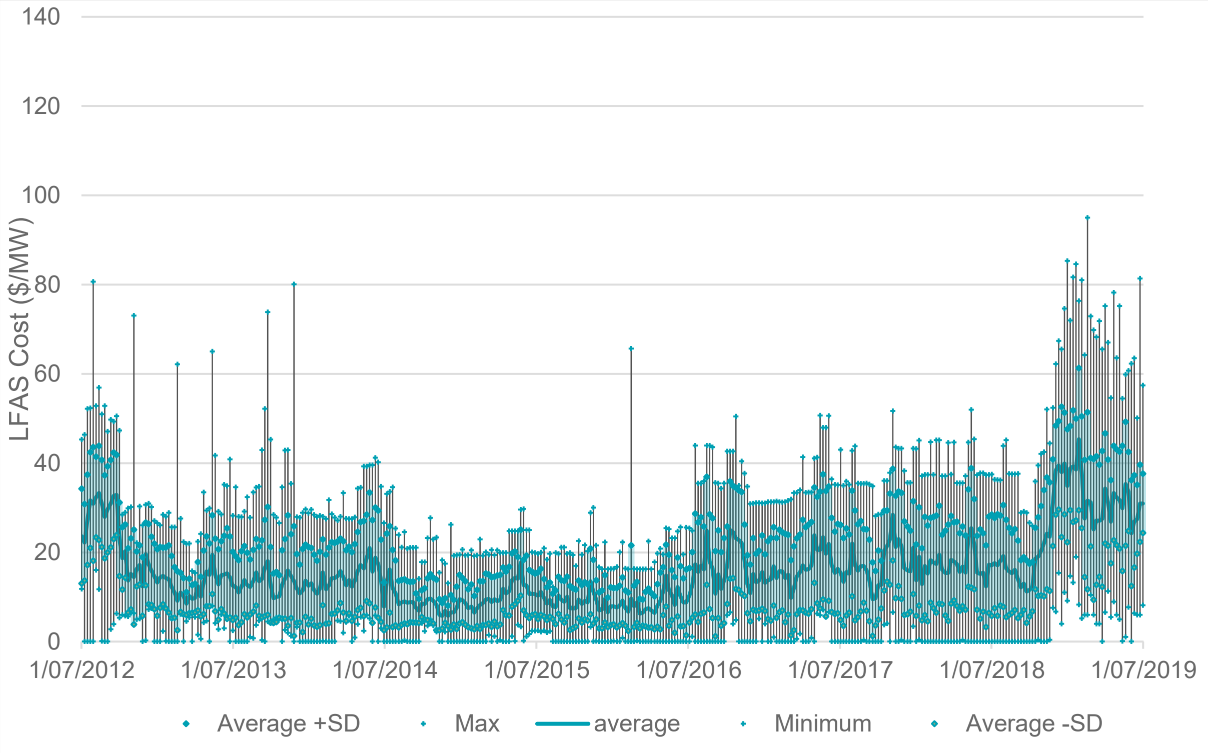


Source: ERA analysis of AEMO data

For the 2018/19 year, the average LFAS Up and LFAS Down[64] have converged for the first time since market commencement.

In Q1 2019, LFAS Up prices were higher than LFAS Down prices for nearly half of all intervals. This trend began in Q4 2018. The convergence of average LFAS Up and Down prices reverses the historical trend of LFAS Down prices being higher than LFAS Up prices.

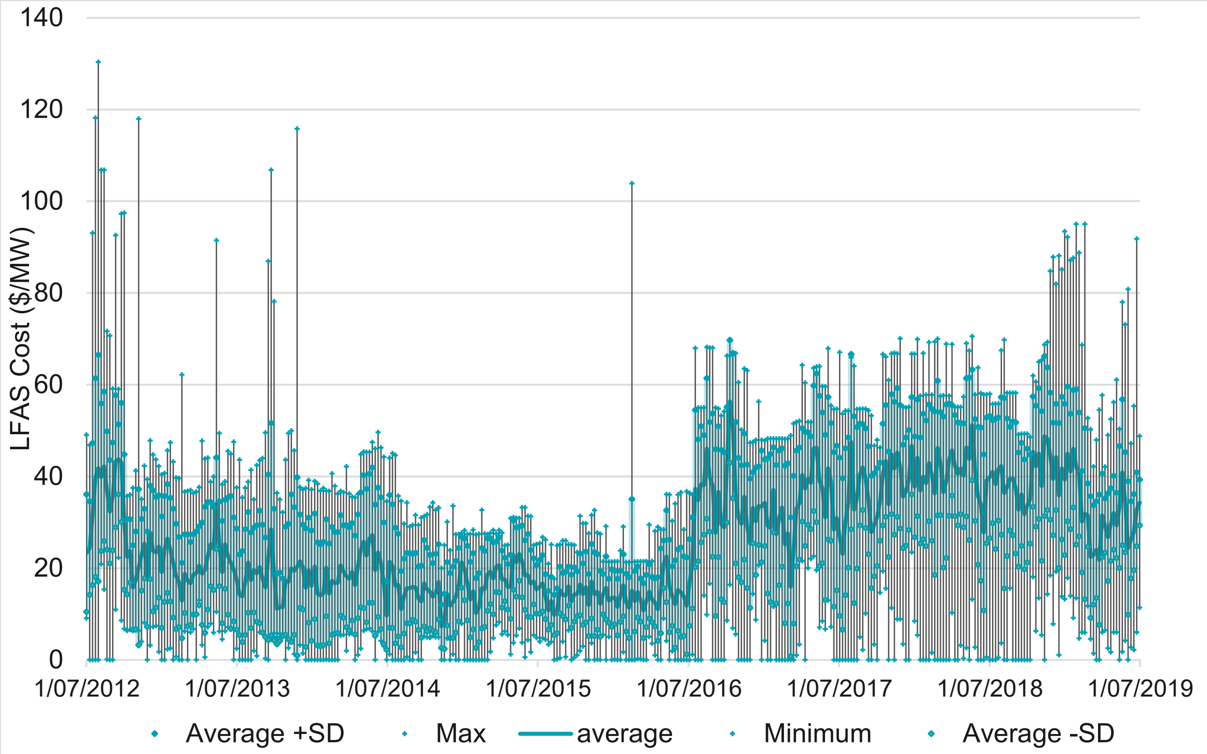
Figure A 13: Load Following Ancillary Services Up summary pricing statistics



Source: ERA analysis of AEMO data

64 LFAS is used to continuously balance supply and demand. LFAS accounts for the difference between scheduled energy (what has been dispatched), actual load, and intermittent generation. LFAS Up requires the provision of additional generation to increase frequency in real-time and LFAS Down requires the reduction in generation to decrease frequency.

Figure A 14: Load Following Ancillary Services Down summary pricing statistics



Source: ERA analysis of AEMO data

Outages

Table A 1 summarises outages by participant, facility and type from 2014/15 to 2018/19 for facilities active in 2018/19 which also lodged outages in the last five financial years.

Overall, Alcoa Wagerup, Muja G7, Muja G8, Pinjar GT3, Pinjar GT9 and Tesla Picton G1 had the largest outages during 2018/19 with an equivalent unavailability factor exceeding 15 per cent. Alcoa Wagerup had the largest forced outage rate at 21 per cent with Muja G8 the only other unit with a forced outage rate about 10 per cent. Planned outages for Muja G7, Muja G8, Pinjar GT3 and Pinjar GT9 all exceeded 15 per cent.

Table A 1: Outages by type, participant and facility 2014/15 to 2018/19

	Planned Outage Rate (%)					Forced Outage Rate (%)					Equivalent Unavailability Factor (%)				
	2014/15	2015/16	2016/17	2017/18	2018/19	2014/15	2015/16	2016/17	2017/18	2018/19	2014/15	2015/16	2016/17	2017/18	2018/19
ALCOA															
ALCOA_WGP	3%	1%	0%	10%	1%	1%	2%	3%	5%	21%	5%	3%	3%	15%	23%
ALINTA															
ALINTA_PNJ_U1	9%	7%	3%	12%	2%	0%	0%	0%	0%	0%	9%	7%	3%	12%	2%
ALINTA_PNJ_U2	6%	9%	2%	4%	11%	0%	0%	0%	2%	0%	6%	10%	3%	6%	11%
ALINTA_WGP_GT	7%	4%	5%	4%	1%	0%	0%	1%	0%	0%	7%	5%	6%	4%	2%
ALINTA_WGP_U2	6%	3%	6%	4%	3%	0%	0%	0%	0%	0%	7%	4%	6%	4%	3%
ALINTA_WWF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
BADGINGARRA_WF1	-	-	-	-	0%	-	-	-	-	0%	-	-	-	-	0%
COLLGAR															
INVESTEC_COLLGAR_WF1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
EDWFMAN															
EDWFMAN_WF1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

	Planned Outage Rate (%)					Forced Outage Rate (%)					Equivalent Unavailability Factor (%)				
GLDFLDPW															
PRK_AG	0%	1%	1%	1%	1%	0%	1%	1%	0%	1%	1%	2%	2%	1%	2%
MERREDIN															
NAMKKN_MERR_SG1	8%	6%	2%	0%	4%	0%	1%	0%	1%	0%	8%	7%	3%	1%	6%
NGENEERP															
NEWGEN_NEERABUP_GT1	1%	2%	1%	1%	2%	0%	0%	0%	0%	0%	1%	2%	1%	1%	2%
SUMMIT SOUTHERN CROSS POWER															
BW1_BLUEWATERS_G2	9%	16%	2%	14%	9%	0%	0%	1%	0%	0%	9%	16%	3%	14%	9%
BW2_BLUEWATERS_G1	8%	11%	10%	1%	10%	1%	1%	46%	5%	1%	9%	12%	56%	6%	11%
NEWGEN_KWINANA_CCG1	3%	14%	6%	5%	6%	0%	1%	0%	0%	0%	3%	15%	6%	5%	6%
STHRNCRS															
STHRNCRS_EG	0%	0%	0%	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	0%	4%
SYNERGY															
COCKBURN_CCG1	6%	12%	17%	35%	0%	0%	0%	1%	8%	3%	6%	12%	17%	43%	3%
COLLIE_G1	5%	7%	8%	8%	6%	1%	1%	0%	2%	1%	6%	8%	9%	10%	8%
KEMERTON_GT11	5%	3%	14%	1%	1%	0%	0%	0%	1%	0%	5%	3%	14%	2%	1%
KEMERTON_GT12	1%	3%	16%	1%	1%	0%	0%	0%	0%	0%	1%	3%	16%	1%	1%
KWINANA_GT2	17%	18%	16%	9%	11%	1%	2%	2%	0%	2%	17%	20%	18%	11%	13%
KWINANA_GT3	13%	12%	17%	9%	10%	4%	3%	1%	6%	0%	17%	15%	18%	17%	10%
MUJA_G5	5%	14%	4%	30%	5%	2%	8%	0%	5%	5%	7%	23%	5%	35%	10%
MUJA_G6	2%	21%	4%	23%	3%	20%	2%	1%	3%	5%	23%	24%	5%	26%	8%

	Planned Outage Rate (%)					Forced Outage Rate (%)					Equivalent Unavailability Factor (%)				
MUJA_G7	21%	14%	14%	5%	18%	23%	1%	0%	0%	7%	43%	15%	14%	5%	25%
MUJA_G8	30%	11%	17%	3%	20%	6%	1%	0%	2%	15%	36%	12%	17%	5%	35%
MUNGARRA_GT1	13%	0%	3%	0%	0%	0%	2%	0%	0%	0%	13%	2%	3%	0%	0%
MUNGARRA_GT3	10%	6%	3%	0%	0%	1%	0%	0%	0%	0%	11%	6%	3%	0%	0%
PINJAR_GT1	0%	6%	0%	11%	10%	1%	0%	0%	0%	0%	1%	6%	0%	11%	10%
PINJAR_GT10	0%	7%	8%	22%	5%	1%	1%	1%	2%	1%	1%	7%	9%	25%	6%
PINJAR_GT11	8%	9%	17%	1%	7%	6%	1%	1%	1%	1%	14%	10%	18%	2%	9%
PINJAR_GT2	0%	6%	0%	3%	1%	1%	0%	0%	0%	0%	1%	6%	0%	3%	1%
PINJAR_GT3	10%	3%	0%	2%	16%	0%	1%	1%	1%	0%	10%	5%	1%	4%	16%
PINJAR_GT4	21%	3%	0%	2%	5%	0%	0%	0%	0%	0%	21%	3%	1%	2%	5%
PINJAR_GT5	0%	8%	0%	3%	0%	0%	0%	0%	0%	0%	0%	9%	0%	3%	0%
PINJAR_GT7	0%	0%	4%	8%	0%	0%	0%	0%	0%	1%	0%	1%	4%	8%	1%
PINJAR_GT9	21%	2%	34%	7%	18%	2%	3%	1%	2%	1%	24%	4%	35%	9%	20%
PPP_KCP_EG1	5%	4%	2%	2%	7%	2%	0%	0%	0%	0%	7%	4%	2%	2%	7%
WEST_KALGOORLIE_GT2	2%	0%	0%	3%	0%	1%	0%	0%	1%	0%	4%	2%	1%	4%	0%
WEST_KALGOORLIE_GT3	3%	0%	3%	0%	0%	0%	1%	2%	0%	0%	4%	3%	6%	0%	0%
TESLA															
TESLA_GERALDTON_G1	2%	1%	2%	3%	2%	0%	0%	0%	0%	0%	4%	1%	3%	4%	4%
TESLA_KEMERTON_G1	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	0%	1%
TESLA_NORTHAM_G1	1%	5%	2%	1%	1%	0%	0%	0%	0%	0%	1%	5%	3%	2%	3%
TESLA_PICTON_G1	1%	0%	1%	1%	2%	0%	0%	0%	0%	0%	1%	2%	1%	2%	39%

	Planned Outage Rate (%)					Forced Outage Rate (%)					Equivalent Unavailability Factor (%)				
TIWEST															
TIWEST_COG1	1%	1%	9%	2%	2%	2%	1%	1%	2%	0%	3%	2%	10%	4%	2%
WENERGY															
PERTHENERGY_KWINANA_GT1	1%	9%	7%	6%	3%	0%	0%	3%	2%	6%	1%	9%	10%	9%	9%

Source: ERA analysis of AEMO data

Appendix 2 List of Figures