Ancillary service costs - Spinning reserve, load rejection reserve, and system restart (Margin Values Cost_LR) for 2021/22

Issues paper

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Tuesday 23 March 2021

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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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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Executive summary

The Australian Energy Market Operator uses ancillary services to maintain the security of the South West Interconnected System. As the largest generator, Synergy is the default provider of these ancillary services. Synergy receives compensation for three ancillary services based on parameters determined by the ERA and used in the market settlement process. The cost of ancillary services is borne by market participants and ultimately passed on to consumers.

The three administered ancillary services are spinning reserve, load rejection reserve and system restart. Spinning reserve and load rejection reserve are complementary but opposite ancillary services, used to maintain system frequency when there is a sudden loss of supply or demand. This can happen when generators fail, or parts of the electricity network become disconnected. The system restart service is needed where the electricity system or parts of the system are subject to widespread blackout.

The compensation parameters include the margin values: the share of the balancing price paid to Synergy to compensate for the margin Synergy could reasonably have expected to earn on energy sales were it not providing spinning reserve. The cost of providing load rejection reserve is represented by the 'L' component of Cost_LR and the cost of providing system restart services, the 'R' component of Cost_LR. The cost for the two services ('L' and 'R') are combined into a total annual sum. The annual cost is then divided into twelve monthly amounts, recovered from market participants on the basis of their share of market consumption and paid to the load rejection and system restart service providers.

In May 2020, the Australian Energy Market Operator (AEMO) proposed rolling over the spinning reserve and load rejection parameters approved for 2020/21, to apply in 2021/22. In November 2020, AEMO provided the ERA with revised system restart costs based on a tender process AEMO is undertaking to replace two system restart contracts that expire in mid-2021.

The ERA is obliged to consider AEMO's proposal when making its determination on the ancillary service parameters to apply in 2021/22, as well as taking account of the Wholesale Electricity Market (WEM) objectives and stakeholder feedback.

The ERA has reviewed AEMO's proposal and conducted its own modelling and investigation of spinning reserve and load rejection reserve requirements and costs over 2021/22. Overall, the ERA's estimated cost of the two services, at around \$9 million, is comparable to that approved in 2020/21. However, the ERA's initial modelling shows the cost of providing spinning reserve falling from \$8.4 million in 2020/21 to \$80,000 in 2021/22 and the cost of providing load rejection reserve rising from \$1.2 million in 2020/21 to \$8.6 million for 2021/22. The changing dynamics of the WEM appear to be driving changes in the quantity and cost of spinning reserve quantity and the cost of load rejection reserve.

The effect of changing market dynamics

The continued installation of rooftop solar has reduced demand for electricity from the network in the middle of the day, which in turn has reduced the need for large generators to operate during this time. Synergy's larger generators provide load rejection reserve by quickly reducing their output in response to a sudden and unexpected drop in demand. As Synergy's larger generators have already lowered their output in the middle of the day, they are limited in how much they can further reduce output to provide load rejection reserve without dropping below the minimum stable level of generation. With Synergy's coal generators unable to reduce output, AEMO needs to schedule more gas generators to provide the load rejection reserve requirement. This increases the cost of the load rejection reserve service as the operating costs of gas generators are generally higher than Synergy's coal generators.

A second consequence of rooftop solar reducing the quantity of electricity supplied by the market in the middle of the day, is a reduction in the quantity of spinning reserve required in the system. If a generator fails, another generator that is providing spinning reserve quickly increases its output to meet the level of demand in the system. The quantity of spinning reserve is partly linked to the risk of the generator with the highest output failing at any point in time. With the larger generators in the system reducing their output in the middle of the day, the output from the single largest generator is less and, accordingly, the quantity of spinning reserve required over this period is less.

Another factor that appears to be reducing spinning reserve costs is the increase in the load following ancillary service (LFAS), which enables AEMO to balance the supply and demand for electricity in real time. There has been an increase in wind generation in the South West Interconnected System (SWIS) over recent years (from around 400 MW in 2012 to around 1,200 MW in 2021). Wind generation is weather dependent and the output from wind facilities can vary by over 200 MW between intervals. AEMO has increased the LFAS requirement to accommodate the greater variability of supply caused by more wind generators in the SWIS. Generators scheduled to provide upwards LFAS can also provide spinning reserve at no additional cost. Consequently, there is more upwards LFAS available to meet the spinning reserve requirement.

In the afternoon and evening, rooftop solar output decreases and demand for electricity from the network increases. The spinning reserve requirement rises as larger generators increase their output in response to the evening demand. However, spinning reserve costs are not rising with the increasing requirement for spinning reserve. This may be due to the gas generators that provide load following ancillary services substituting for spinning reserve.

The modelled cost of spinning reserve is very low, reflecting the fact that generators providing LFAS and load rejection reserve can also provide spinning reserve at zero incremental cost. There remain some intervals where Synergy is needed to supply spinning reserve and the cost of this spinning reserve is high. However, intervals with a cost above zero comprise only about 5 per cent of all intervals.

The ERA’s initial modelling may not have picked up changes in the market that require an increase in spinning reserve. Although the quantity of spinning reserve is typically linked to the loss of the generator with the highest output, the market rules refer to having sufficient spinning reserve to also cover the most severe contingency event, such as the loss of a transmission line and the generators connected to it. AEMO recently provided public advice that it may need to increase the spinning reserve requirement if the 330kV transmission line north of Perth fails, disconnecting the Yandin and Warradarge wind farms and the NewGen Neerabup coal generator. The sudden loss of these generators could result in a disturbance in the electricity network, such as a change in frequency or voltage, that may cause a proportion of rooftop solar systems to disconnect across the SWIS. The inverters contained in rooftop solar systems identify the change in the quality of power in the network and disconnect until the network stabilises and the rooftop system can reconnect. The momentary loss of rooftop solar would increase demand for electricity from the network that cannot be met unless AEMO has sufficient spinning reserve available. The ERA will continue to work with AEMO to understand this emerging change to the spinning reserve requirement as part of its margin values determination.

The ERA is interested in market participants’ views on the changes to the market as described above, and the consequences for the quantities and costs of LFAS and spinning reserve. This will assist the ERA to test its analysis of the likely drivers of change to spinning reserve and load rejection reserve quantities and costs.

1. Background

The ERA is responsible for determining parameters used to compensate the suppliers of three ancillary services used in the WEM to maintain system security: the spinning reserve and load rejection reserve services, and the system restart service needed to restore the electricity system in the event of a blackout. These services are explained further in section 2.

The market rules require AEMO to submit a proposal annually for the parameters for spinning reserve (known as the margin values and spinning reserve quantity). AEMO can propose revised load rejection reserve and system restart service parameters (known as Cost_LR) every three years or more frequently if AEMO considers the Cost_LR parameters will materially change year on year.[1] Since 2019/20, AEMO has proposed revised Cost_LR parameters each year.

AEMO submitted proposed spinning reserve and load rejection reserve parameters for 2021/22 on 30 June 2020. AEMO chose not to model new parameters as it preferred to reserve resources to respond to contingencies that might arise from the COVID-19 pandemic.[2] For spinning reserve settlement parameters and load rejection reserve, AEMO proposed rolling over the ERA's determined values for the 2020/21 financial year.

On 30 November 2020, AEMO submitted revised system restart costs. This included preliminary outcomes from the tender process that AEMO is running to procure new system restart services for when two existing contracts expire at the end of June 2021.

In determining the parameters for spinning reserve and the costs for the load rejection reserve and system restart services to apply in 2021/22, the ERA will consider AEMO's proposal in the context of the WEM objectives.[3] The ERA must publish an issues paper and invites public submissions on this paper.[4] The ERA must make its determination on the values to apply in 2021/22 by 31 March 2021.

The ERA undertook modelling to estimate likely spinning reserve and load rejection reserve costs and quantities for 2021/22. The results of the modelling suggested a shift in the cost of ancillary services. The cost of providing spinning reserve falls and there is a substantial increase in the cost to provide load rejection reserve.

The ERA investigated this further and in this issues paper explores ways in which the changing market dynamics of the WEM may be driving changes to the costs of these ancillary services.

This issues paper is intended to assist interested parties to make submissions on what maybe driving the changes in ancillary services parameters estimated for 2021/22.

[1] Wholesale Electricity Market Rules, 1 February 2021, clause 3.13.3A(a) and 3.13.3c (online).

[2] Zibelman A, 2020, *COVID-19 Pandemic – AEMO review of regulatory activities under Wholesale Electricity Market Rules and proposed actions*, letter to ERA dated 24 April 2020, p. 2

[3] Wholesale Electricity Market Rules, 1 February 2021, clause 1.2 (online).

[4] Ibid. clause 3.13.3A(b)

2. Spinning reserve and load rejection reserve

2.1 What is spinning reserve?

Spinning reserve refers to generation capacity and interruptible load used to maintain power system frequency within the electricity system's tolerance range when there is a sudden unexpected increase in demand, or loss of supply. This might occur when a generator or network asset trips or fails, or because network demand rises following a sudden, sustained, and unexpected drop in rooftop solar output. The market rules allow spinning reserve to be provided by scheduled generators, interruptible loads or a combination of the two.[5]

As with other ancillary services, the spinning reserve standard is set by AEMO and audited by the ERA.[6] The market rules specify that the standard is the greater of 70 per cent of the total output of the generator with the highest total output at that time, or the highest expected load ramp over a period of fifteen minutes. The technical rules set similar requirements but also refer to the need to cover the most severe contingency event.[7] Contingencies can be the loss of a generator or a loss of part of the network such as a transmission line and generators connected to it.[8]

The market rules provide for three classes of spinning reserve, which operate over different timeframes.[9] AEMO has been primarily concerned with generators capable of responding within six seconds. The system's electricity frequency declines when supply is lost unexpectedly. If this frequency decline is not arrested by spinning reserve, customer load is shed by disconnecting loads to reduce demand until the supply and demand are brought back into balance.[10] If this balance does not occur in time, generator protection settings may cause generators to systematically disconnect, which could lead to a system blackout.[11]

2.2 What is load rejection reserve?

Load rejection reserve provides a rapid decrease in generation output when a large amount of load is lost, such as when a transmission line trips off because of overloading. When this happens, the system frequency increases. The generators providing load rejection reserve automatically reduce output to maintain system frequency within the limits necessary for security of the system. Typically, these large load rejection events happen a few times each year.

AEMO sets the quantity of load rejection reserve necessary to meet the standard described in the market rules. The standard for load rejection reserve must be sufficient to keep frequency below 51 Hertz for all credible load rejection events. The quantity of capacity needed to maintain the standard for load rejection reserve may be relaxed by up to 25 per cent where AEMO considers the probability of transmission faults to be low. Historically,

5 Wholesale Electricity Market Rules, 1 February 2021, clause 3.9.2, (online)

6 Ibid, clause 3.11.12

7 Western Power, 2016, Technical Rules, online, clause 2.2.1(d), (online), p.10

8 Wholesale Electricity Market Rules, 1 February 2021, clause 3.8A.2, (online)

9 Ibid. clause 3.9.3, (online)

10 This is also called under-frequency load shedding where parts of the electricity network are disconnected to prevent widespread blackouts.

11 The Technical Rules require generators to maintain output for a period of time (ride-through) when the system frequency falls or rises outside normal limits. Refer to Technical Rule 3.3.3.3 (b) in Western Power, 2016, *Technical Rules for the South West Interconnected System*, Revision 3, ERA, (online), p. 44

AEMO has set the quantity of load rejection reserve needed to maintain the standard at a maximum of 120 MW, which AEMO can relax down to 90 MW. In June 2020, AEMO reduced the maximum load rejection reserve to 90 MW.[12]

AEMO is progressively reviewing and implementing practices to manage the required load rejection reserve quantity more efficiently. AEMO reviewed what was needed to manage frequency, and now accounts for other factors, such as load relief, that reduce the amount of load rejection reserve required for system security.[13] In practice, the required quantity varies with the size of the largest load rejection contingency and with available load relief.

Wind farms and certain other generators effectively provide a load rejection reserve through the conditions in network access contracts. These generators have protection settings that reduce output when the frequency rises above a threshold (such as 51 Hertz), above which they automatically reduce their output. This allows AEMO to tolerate lower levels of load rejection reserve in some circumstances and reduces the need to reschedule generators when load rejection reserves reduce in response to changes in market conditions.

AEMO's efforts to manage load rejection reserve are a welcome initiative to help reduce the cost of this ancillary service to the market.

2.3 How ancillary service costs are recovered from the market

2.3.1 Spinning reserve service

The availability payments (the compensation for providing the service) for spinning reserve are recovered via multipliers (the margin values for peak and off-peak) that are applied to the balancing market price and the quantity of spinning reserve modelled for the period. The margin values are an administered mechanism to compensate Synergy for providing spinning reserve. This involves estimating the availability cost (the cost to provide spinning reserve) and then converting the availability cost to a proportion (a percentage margin) of the balancing price. This is done via the following equation:

Formula 1

$$a_t = \frac{1}{2}m \times p_t \times q_t$$

where a_t is availability payment for an interval t, m is margin value, p_t is balancing price for the interval and q_t is spinning reserve quantity for the interval.[14]

The market rules provide for peak and off-peak margin values to recognise the differing availability costs during peak and off-peak intervals.

Due to the complexity of an electricity market, modelling is a central element of determining the values used in market settlement. Modelling accounts for changes in fuel cost and other

12 AEMO, 2020, *Ancillary Services Report for the WEM 2020*, (online), p. 17

13 Some loads, such as motors, increase consumption in response to system frequency. In the case of load rejection events, as system frequency increases, so too will demand. Termed 'load relief' this reduces the amount generators need to reduce output by, and the size of the reserve. This varies with system demand and can be around 30 MW for a frequency increase to 51 Hertz.

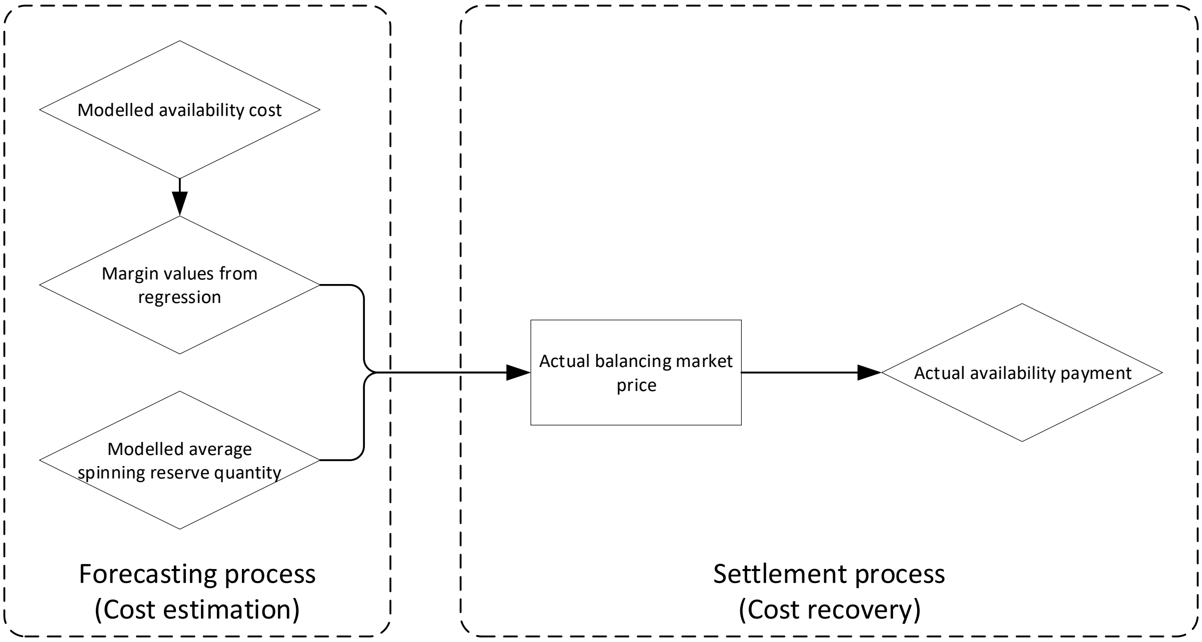
14 The equation is simplified by excluding the reduction in spinning reserve quantity that can be provided by the upwards LFAS.

changes to the operating cost of generators, and the number of generators participating in the WEM.

The ERA uses regression analysis to derive the margin values. This analysis determines the slope of the line required to approximate the availability cost when applied to forecast balancing market prices and the average spinning reserve quantity provided by Synergy.

At settlement, the margin values are applied to the estimated spinning reserve quantity from the forecast model after deducting the quantity of upwards LFAS and the actual balancing market price. This process is indicated in Figure 1 below.

Figure 1: Application of modelled values to cost recovery



The actual availability payments (as distinct from the modelled availability cost) should compensate Synergy for the cost of providing spinning reserve. Modelling is used to identify the expected availability cost and to estimate the margins through which the availability cost is to be recovered. AEMO's proposal must reflect:

- The margin that Synergy could reasonably have expected to earn on energy sales foregone due to providing spinning reserve.
- The consequential reduction in generator efficiency for Synergy's generators providing spinning reserve. Generator efficiency is reduced because a generator is operating at part load only prior to being dispatched to provide spinning reserve.

The market rules and technical rules require enough spinning reserve to be able to cover whichever is the greater: [15]

- a loss of 70 per cent of the largest output of any generator
- a loss of 70 per cent of the largest contingency on the network at the time

[15] Wholesale Electricity Market Rules, 1 February 2021, clause 3.10.2(a), (online)
Western Power, 2016, *Technical Rules for the South West Interconnected System*, Revision 3, clause 3.3.3.3 (b), (online), p. 44

- the expected maximum increase in demand over a period of 15 minutes.

2.3.2 Load rejection reserve and system restart service

The Cost_LR mechanism is a simpler mechanism than that used for spinning reserve. Two separate components, 'L' for load rejection and 'R' for system restart service, are added together and divided into monthly charges billed to market participants on the basis of their share of market consumption. Providers of system restart service are paid their share of the contracted sum and any shortfalls in the ERA approved amount are recovered through a shortfall charge. The shortfall charge collects any difference between the contracted sum entered into between AEMO and suppliers of system restart service and the sum determined by the ERA.

2.4 AEMO's proposal

On 30 June 2020, AEMO submitted its proposal to the ERA for approval. AEMO considered that modelling undertaken for its 2020/21 proposal would be suitable for 2021/22.[16] After reviewing the modelling assumptions in its 2020/21 proposal, AEMO concluded that:

- Demand characteristics were substantively the same between 2020/21 and 2021/22.
- Fuel prices had not shifted much and gas market prices likely sat between the base case and the sensitivity scenario the ERA used to inform the determination for 2020/21.
- Load following requirements were sufficiently similar to the modelled values.
- The new suppliers in the market were small or not likely to materially affect modelled values.

On 30 November 2020, AEMO submitted an amendment to account for a change in expected system restart service cost. AEMO proposed the following values:

Table 1: AEMO proposed ancillary service settlement parameter values for 2021/22

Parameter	ERA approved (2020/21)	AEMO proposed (2021/22)
Margin_Peak (%)	25.46	25.46
Margin_Off-Peak (%)	21.42	21.42
SR_Capacity_Peak (MW)	252.03	252.03
SR_Capacity_Off-Peak (MW)	240.66	240.66
Cost_L - Load rejection reserve ($m)	1.167	1.167
Cost_R - System restart ($m)	2.868	3.369

Source: ERA determination and AEMO proposal

[16] AEMO, 2020, *Margin Values and Cost_LR parameters for the 2021/22 financial year*, (online)

3. Changes to the market in 2021/22

The electricity market is undergoing substantial changes in ways that appear to be affecting the required quantity and the cost of providing spinning reserve and load rejection reserve services. There has been a substantial increase in the quantity of non-scheduled generation entering the WEM, both as market participants and as substitutes for market demand in the form of rooftop solar generation. Non-scheduled generators, such as wind and solar farms, bring low-cost generation into the market and distributed generation reduces electricity demand from the market.

The change in market dynamics appears to be changing the relative costs of spinning reserve and load rejection reserve, such that spinning reserve appears to be declining in cost and load rejection reserve escalating.

3.1 Drivers of spinning reserve and load rejection reserve costs

AEMO sets the quantities of each ancillary service in accordance with the market rules and in response to market drivers. The quantity and type of ancillary services AEMO uses to maintain the security of the electricity network depend on the physical characteristics of the network and which generators are operating at any point in time. Not all generators provide every ancillary service that is needed to reliably meet consumer demand and so, as the largest generator, Synergy is the default provider of these services.

The quantity of electricity demanded from large generators is changing as consumers obtain rooftop solar systems. This is changing how electricity is supplied and the quantities of different ancillary services required to maintain a secure electricity supply.

The ancillary service buffers or reserves are set to ensure the system remains stable when individual generators or parts of the network encounter problems. The reserves are affected by the output of individual generators, any risks with the way the network is structured and the location of generation connected within the network. Spinning reserve and load rejection reserve ensure there is sufficient capacity to respond to generators coming online or going offline. Another reserve, the LFAS, is there to be able to match the demand for and supply of electricity in real time given the variable output from renewable generators.

The market drivers affecting the size and cost of ancillary service reserves include:

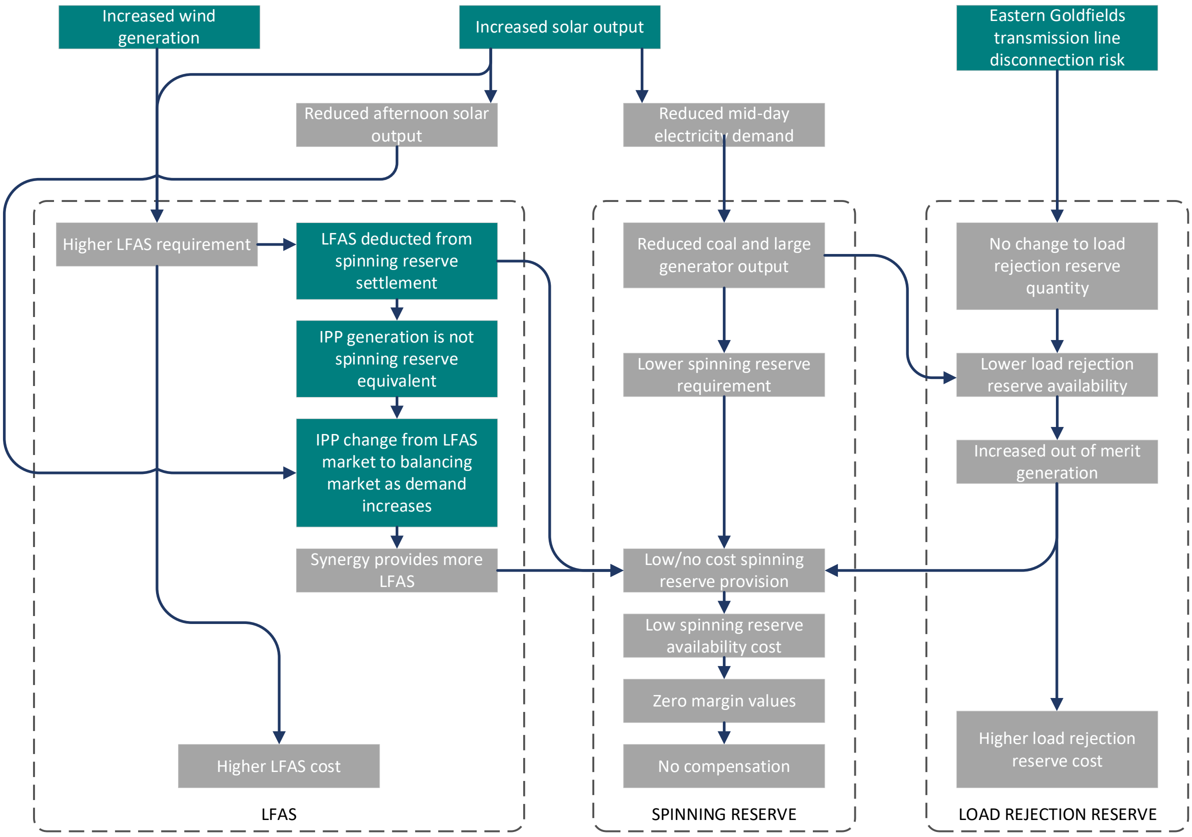
- The largest single source of generation in the market at a point in time (affects spinning reserve quantity).
- The largest combined supply that would be lost due to a single network failure (affects spinning reserve quantity and load rejection reserve).
- The supply variability resulting from non-scheduled generators such as wind and solar (affects the quantity of LFAS that can substitute for spinning reserve).
- The quantity of LFAS that can provide a spinning reserve or load rejection response.[17]

[17] LFAS is used to balance supply and demand in real time. The quantity of load following is driven by the variability in load, and the due to the output of wind and solar.

Collectively these factors can increase or reduce the requirement for different ancillary services, change the generators available to provide ancillary services and either reduce or increase the cost of delivering the ancillary services.

The interactions between these factors and their effect on the ancillary services are outlined in Figure 2. The green boxes identify market drivers and the grey boxes identify how the drivers affect the quantities and costs of each ancillary service. Figure 2 contains a dashed box for each of the three ancillary services. These dashed boxes show the major effects each of the drivers has on the quantities and costs of each respective ancillary service.

Figure 2: Flow chart of market drivers



The following section outlines the changing market dynamics and how the main drivers in Figure 2 interact with each other.

3.1.1 Changing market dynamics

Rooftop solar is reducing electricity demand from the network during the middle of the day.[18] Historically, spinning reserve quantities have been driven by the largest output from any generator operating at the time. As electricity demand on the network falls, the opportunities for large generators to maximise output also falls and the spinning reserve requirement falls. The ERA explored the effect on large, inflexible coal-fired baseload generators in its WEM effectiveness review published in 2019.[19]

Synergy is the only provider of load rejection reserve and historically its large coal generators have provided load rejection reserve at, or close to, no cost. Coal generators are generally

[18] ERA, 2020, *Report on the Effectiveness of the Wholesale Electricity Market 2020*, (online), pp. 30-36

[19] ERA, 2019, *Report to the Minister for Energy on the effectiveness of the Wholesale Electricity Market 2018*, (online), pp. 8-10

low cost and usually cleared to run in the market. These generators will incur no material costs if required to reduce their output to provide the load rejection reserve service. Consequently, the load rejection reserve cost has typically been very low. Costs are incurred where more expensive plant needs to be brought online to provide the reserve when generators cleared to run in the market cannot.

With rooftop solar reducing demand for electricity from the network during the middle of the day, the large generators respond by reducing their output. As output lowers, the generators' capacity to provide load rejection reserve also falls as each generator approaches its minimum generation limits. If the total output falls below a generator's minimum stable generation level there is a risk that it could fail and be unavailable later when needed. As a result, more flexible gas-fired generation may be brought online to provide load rejection reserve.

Generators are generally dispatched according to a merit order where offers are stacked from least cost to most expensive. Under some circumstances, generators may need to be dispatched regardless of their costs to maintain system security – this is termed "out of merit". Most generators brought online or taken offline can be identified because their output is discretely bid into the market.

Synergy's out of merit costs cannot be readily identified. This is because unlike other market participants, Synergy, which holds roughly half the accredited capacity in the market, is able to offer its bids into the market as a portfolio rather than as individual facilities. Consequently, scheduling decisions affecting Synergy's dispatch (and their operating cost) are independent of its bids and cannot be separately identified unless the overall quantity changes. Low cost generators such as coal plant can be replaced with high cost generators such as gas peaking plant without affecting the revenue Synergy earns. Synergy can therefore incur costs that are invisible to the normal market compensation mechanisms (constrained on payments) and from the market data. Modelling is necessary to estimate these out of merit costs to understand the level of compensation due to Synergy for the load rejection reserve cost.

As demand falls in the middle of the day, the balancing market price also falls as lower-cost generators set the market price. Where this occurs, Synergy's gas-fired generators providing load rejection reserve may find their operating costs are not recovered through the balancing market. Cost_LR provides compensation for this. These same generators can also provide spinning reserve from any unused capacity headroom above what is dedicated to load rejection reserve (that is, the minimum generation plus the load rejection reserve itself) which incurs no additional cost unless it is called to provide spinning reserve. According to Synergy, AEMO is having to schedule gas fired generation to provide load rejection reserve where coal fired generators cannot.[20] The use of higher-cost gas plant to provide this service increases the cost of load rejection.

The increase in the quantity of wind generators connected to the transmission network and rooftop solar connected to the distribution network have resulted in a higher load following requirement.[21] AEMO wrote to the ERA in August 2020 and September 2020 seeking an

[20] Cox A., 2019, *Ancillary services parameters – 2019 draft methodology and assumptions report, public submission*, Synergy, online, p. 1, and Baker K., 2020, *Spinning reserve, load rejection reserve and system restart costs: Margin Values and COST_LR ancillary services parameters for 2020/21 issues paper, public submission*, Synergy, (online), p. 4

[21] AEMO, 2020, *2020 Ancillary Services Report*, (online), p. 16

increase in the quantity of load following available to it to manage supply and demand.[22] This was approved in September 2020.[23]

Upwards LFAS is considered equivalent to spinning reserve in the market rules.[24] Where capable, generators providing upwards LFAS will also increase their output in response to a contingency event. With one exception, the control systems and plant configuration of Synergy's generators used for load following enables them to also provide a spinning reserve response.[25] These generators are compensated through the load following market and incur no additional cost to provide spinning reserve. Similarly, price setting generators do not forego sales to be capable of increasing their output and the marginal cost to provide spinning reserve is zero.[26]

The falling solar output in the afternoons and into the evenings has two effects on Synergy's costs for spinning reserve.

1. Synergy's larger generators with slower ramp rates can increase their output progressively to meet the evening maximum demand. As these generators increase their output, the spinning reserve requirement increases.

2. The large, inflexible thermal generators with slow ramp rates alone are not sufficient to meet the rate of change in demand and gas fired generators come into merit and are dispatched, increasing the balancing market price. With the increase in balancing market prices, non-Synergy LFAS suppliers tend to withdraw from the LFAS market and bid into the balancing market.

The consequence of these two effects is an increase in the low-cost spinning reserve substitutes (upwards LFAS) available from Synergy's generators, which reduces the quantity of spinning reserve that AEMO needs to schedule. The evening rise in spinning reserve requirement is offset to some degree by the increased LFAS.

3.1.2 Is there market evidence of the changes?

The market data contains evidence that changing market dynamics may be affecting the cost to deliver ancillary services. There has been a change in the generator that typically sets the spinning reserve requirement. In 2012, Collie set the requirement between 70 per cent to 80 per cent of the time. In 2020, this had fallen to between zero and 30 per cent of the time.

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22 AEMO, 2020, *Proposed revised 2020-21 LFAS ancillary service requirement*, (online), pp. 1-2 and AEMO, 2020, *Implementation of proposed increase to the Load Following Ancillary Service (LFAS) requirements*, (online), pp. 1-4

23 ERA, 2020, *Approval of revised 2020-21 LFAS ancillary service requirement*, (online), pp. 1-2

24 LFAS are the frequency keeping ancillary services that balance supply and demand in real time. These are LFAS_UP or LFAS raise which increase output to manage shortfalls in supply and LFAS_DN, LFAS down or LFAS lower which reduces output when there is oversupply.

25 AEMO does not consider Cockburn CCG to be capable of providing a spinning reserve response. While some IPP LFAS may be able to provide a response, without an obligation to ensure the control systems remain capable of providing a response, AEMO considers it cannot rely on them to do so. Thus, non-synergy LFAS providers are deemed unable to provide a spinning reserve response. ERA, 2020, *Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21 – Determination,* (online), p. 31

26 The price setting generator is termed the 'marginal generator'. It may only be required to provide part of the offered output to the market. Where the marginal generator has unused capacity, it may be available to provide a spinning reserve response but incurs no cost to be available to do so. For example, if a 200MW generator is the price setting generator, but the demand only requires 150MW of its output, it still has 50MW available to increase its output that could be used to provide spinning reserve at no cost.

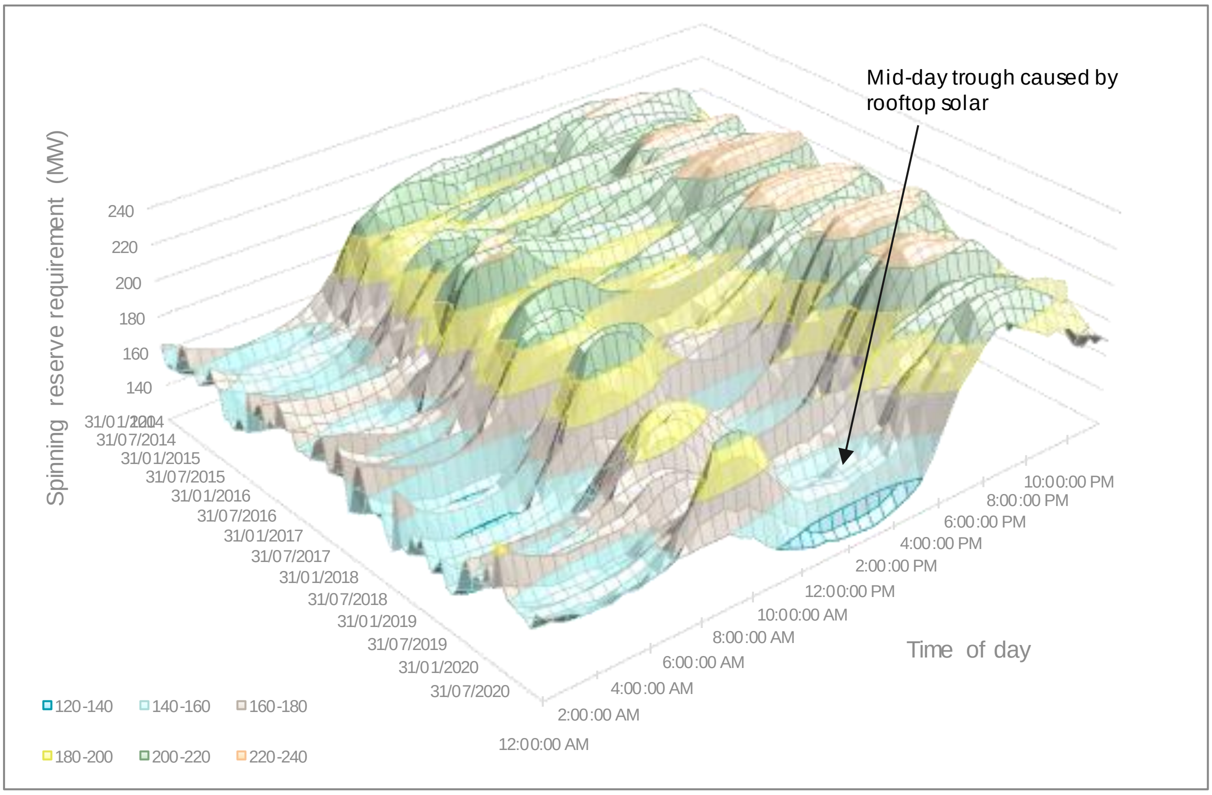
Figure 3 shows that the average levels of spinning reserve requirements are lower and that this is most pronounced in the middle of the day. This requirement increases with network demand from mid-afternoon into the evening period when rooftop solar generation reduces and the output of the larger generators increases.

One complicating factor is the inability to identify which of Synergy's generators are run where their cost exceeds the balancing price. Generators may be substituted for each other under the umbrella of the portfolio and may be used for managing general balancing duties within the portfolio, providing load following, spinning reserve, and load rejection reserve.

Changes to the requirements for spinning reserve ancillary services are apparent over time. Figure 3 below shows the spinning reserve requirement by quantity and time of day over 6 years, based on 70 per cent of the single largest generator output in the WEM.

The midday contingency risk reduced from around 205 MW in February 2017 to around 165 MW in February 2020. The early evening contingency risk reduced from around 220 MW in February 2017 to around 215 MW in February 2020.

Figure 3: Monthly average spinning reserve requirement over time and by time of day



Source: ERA analysis of AEMO data

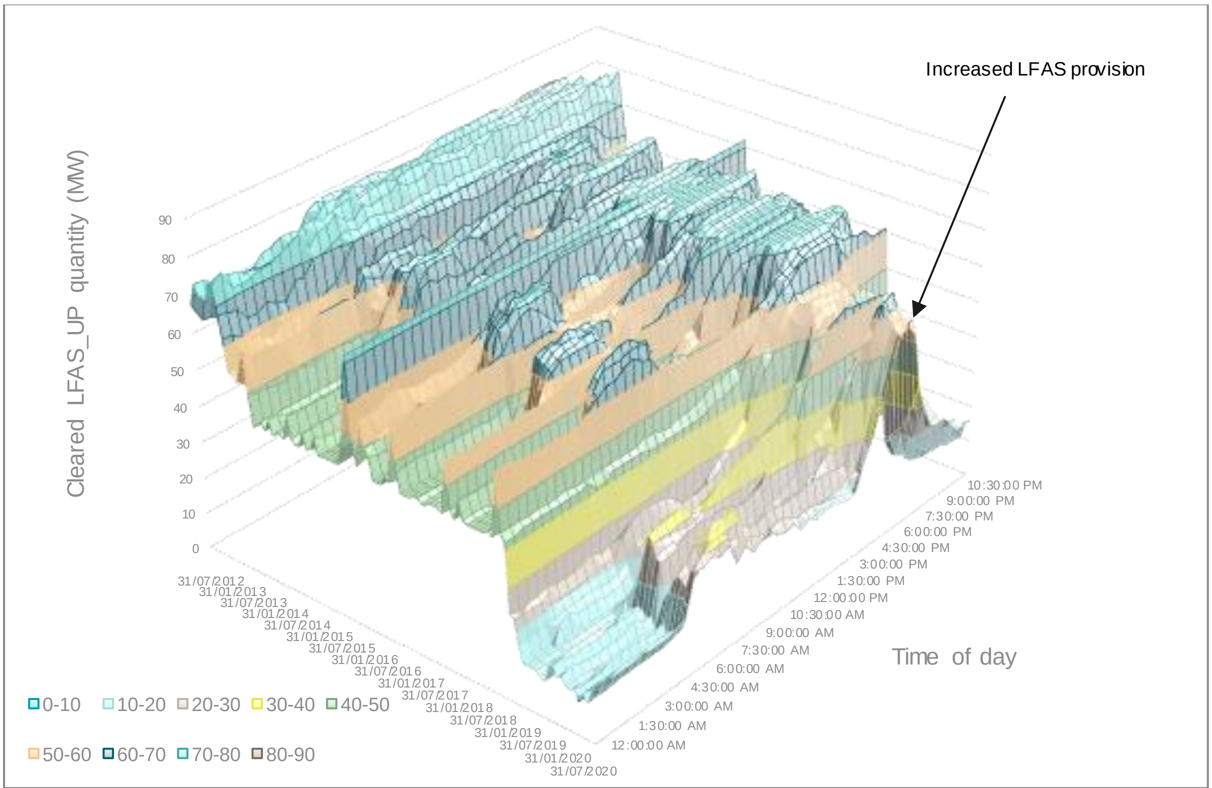
The cost for spinning reserve depends on the type of generator providing the reserve and where it sits in the merit order. The reserve provided by some generators costs nothing where the costs accrue to a different reserve (such as LFAS or load rejection reserve), or where they are the price setting generator.

With a lower spinning reserve requirement in the middle of the day, the target is met first by no cost providers and then by low cost providers. However, not all generators registered to provide LFAS can also provide spinning reserve. AEMO considers that only Synergy's units (with the exception of Cockburn) can be relied upon to provide a spinning reserve response.

The more upwards LFAS provided by Synergy, the less dedicated spinning reserve needs to be scheduled by AEMO.

Synergy's participation in the LFAS market has reduced over time in response to independent power producers participating in the market. Figure 4 shows Synergy's cleared load following capacity over time and by time of day. This shows that with third-party participation in the load following market the quantity of upwards LFAS provided by Synergy has fallen; however, this has not been consistent for all time periods. Third-party generators tend to withdraw from the LFAS market from mid-afternoon into the evening, leaving Synergy as the main provider. The consequence is that the market requires more spinning reserve while Synergy is increasing the quantity of LFAS. This means that AEMO can schedule a smaller quantity of generation to provide spinning reserve that incurs a cost.

Figure 4: Monthly average Synergy cleared capacity in the LFAS market



Source: ERA analysis of AEMO data

Questions

What are stakeholders' perspectives on market dynamics changing the quantity and cost of ancillary services?

Do AEMO's proposed spinning reserve and load rejection reserve costs represent the cost of these services, given changing market dynamics? If so, why and if not, why not?

3.1.3 Uncertainty and modelled outcomes

The ERA's modelling results for 2021/22 indicate a substantial shift in the cost of ancillary services. This section details the shift in the modelled values and possible drivers of the shift, and explores indicators in the market data and outcomes that support the modelling findings.

At around $9 million, the combined value of the spinning reserve availability cost and load rejection reserve is broadly comparable to that determined for 2020/21. However, the allocation of cost between spinning reserve and load rejection reserve has changed. In 2020/21 the availability cost for spinning reserve was estimated to be $8.4 million and for load rejection reserve was $1.2 million. In the ERA's modelled results for 2021/22, this allocation has changed to estimated spinning reserve costs of $80,000 and load rejection reserve of $8.6 million.

With the exception of Synergy, which offers as a portfolio, all generators' offers to the market reflect their individual expectations of marginal variable operating cost. The costs of individual generators within Synergy's portfolio are not transparent to the market and each tranche of generation offered is not tied to a particular generator. Over the course of a day, the estimates of which generators are doing what duty from which the market offers are derived may change as system operators schedule generators on and off to manage the output of Synergy's fleet of generators in response to changing market circumstances. While this makes the operation of the market flexible for the system operators, the consequence is that the costs are not clear, and nor is it clear what generators are providing what services.

What is not apparent from the actual market data is the extent to which, within the portfolio, generators are run out of merit, whether they also provide spinning reserve, and how much unused capacity is available from the marginal generator when Synergy sets the price. This comprises the greatest area of uncertainty about the cost Synergy incurs when providing spinning reserve. The ERA's modelling simultaneously optimises solutions to minimise the cost of energy, spinning reserve, LFAS and load rejection reserve. The WEM does not have the same optimisation process. Energy and ancillary services are scheduled separately, so it is conceivable that cost outcomes for Synergy may differ as a result.

On 1 January 2021, AEMO informed the ERA of a decision to increase the spinning reserve quantity by between 70 MW and 130 MW effective immediately for "particular trading intervals" due to AEMO's preliminary analysis that suggested some distributed solar generation would disconnect.[27] This was also communicated generally to the market via a dispatch advisory that stated:[28]

> Based on recent investigations of power system events, AEMO has identified that during certain conditions the largest contingency event that would result in generation loss needs to include loss of rooftop PV generation. Going forward, AEMO may be

[27] Sharafi D., 2020, *Increase in Trading Interval Spinning Reserve Requirement*, AEMO, pp. 1-2

[28] AEMO, 2020, *Dispatch Advisory 207721*

> required to increase the Spinning Reserve Requirement to ensure system security following the loss of this largest contingency. AEMO will continue to investigate and will advise further details when more information is available.

While there has not been sufficient time to evaluate the implications of AEMO's decision for this issues paper, the timing and materiality of the additional spinning reserve requirement may affect the ERA's modelled results. The contingency could drive material changes to generator scheduling and alter the market dynamics that appears to have influenced ancillary services scheduling in the market, and in the modelling.

After receiving AEMO's advice the ERA held workshops with AEMO to identify the elements affecting the scheduling of additional spinning reserve. The ERA will continue to explore this with AEMO, Synergy, and Western Power as it refines the modelling for the final determination.

3.2 Ancillary service modelled outcomes and costs

The ERA undertook this modelling on the PLEXOS modelling software using a model configured with market data collected for the ERA's market surveillance functions and generators' standing data. A description of the modelling process and ongoing model refinement is summarised in Appendix 1.

In Appendix 2, the ERA outlines its reasons for modelling spinning reserve and load rejection reserve costs for 2021/22.

The ERA began modelling using input costs provided by market participants.[29] The inputs were then adjusted to account for the past bidding behaviour of market participants, such as generation bid at the floor or generation bid at the cap.[30] The ERA then ensured constraints were included in the model to apply to the output of generators connected under the generator interim access contracts.[31] The generators connected under generator interim access contracts avoid the cost of network augmentation on the understanding that when a line approaches capacity, the generator's output will be reduced.[32]

The ERA's modelling consistently delivered extremely low margin values. Table 2 compares these results with an additional set of scenarios that exclude the assumption of third-party contracted spinning reserve.[33] AEMO typically contracts third-party providers of spinning reserve and two contracts are understood to be in place for 2021/22. The additional set of scenarios covers the risk that third-party participation would cease without adequate remuneration. The additional scenarios indicate a higher cost of spinning reserve but the margin values remain at zero because of the similar cost distribution to other scenarios.

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29 These runs just used generator information collected under market rule 2.16 and standing data provided to AEMO.

30 The ERA applied factors or mark-ups to the output costs of generators to account for historical bidding patterns including bids below zero and capacity bid at the caps.

31 The estimated wind outputs from selected wind farms were adjusted downwards to reflect the anticipated outputs under the generator interim access contracts.

32 Energy Transformation Taskforce, 2019, *Foundation Market Parameters*, (online), p. 10

33 Under market rule 3.11.8 AEMO may enter into ancillary service contracts for spinning reserve where it does not consider it can meet the requirement from Synergy's registered facilities or where the contract is a less expensive alternative to services provided by Synergy.

Table 2: Modelled ancillary service values

Parameter		With contracted Spinning Reserve	Without contracted Spinning Reserve	AEMO's proposed values
Balancing market Price ($/MWh)	Peak	18.33	15.92	37.67
	Off-peak	25.25	24.74	40.47
Availability cost – SR ($)	Peak	33,037	77,835	5,042,000
	Off-peak	47,265	89,640	3,353,000
	Total	80,302	167,475	8,395,000
SR requirement (MW)	Peak	171.9	171	188.17
	Off-peak	163.6	161	178.90
Margin Values (%)	Peak	0	0	25.46
	Off-peak	0	0	21.42
Availability Cost – LRR ($)	Peak	6,075,773	6,154,000	274,000
	Off-peak	2,540,610	2,612,799	893,000
	Total	8,616,383	8,766,799	1,167,000

Source: ERA modelling

The distribution of availability cost by interval for spinning reserve shows that high cost intervals - approaching $12,000 per interval - comprise less than one fifth of one per cent of all half-hour trading intervals in a year. Most intervals incur no cost or a cost very close to zero. This is because for most intervals the requirement is met by low or no cost generators and LFAS quantities.

The regression analysis used to determine margin values reduces the influence of outliers more than other methods but yields margin values that are functionally zero. The implication of these margin values is that Synergy and other spinning reserve providers would not be compensated as AEMO's market settlement software cannot input values small enough to be rounded to zero.

The ERA has options to ensure that the existing mechanisms can appropriately compensate Synergy. The ERA could roll the existing values over from 2020/21 and rely on the balancing price and 'L' component of Cost_LR combined to recompense the total cost of load rejection reserve and spinning reserve. With a low cost of spinning reserve though, this would tend to over-compensate contracted spinning reserve and with high balancing price would under-compensate Synergy.

Synergy's compensation for spinning reserve through the margin values is sensitive to future balancing prices. AEMO's modelling of spinning reserve for the 2020/21 financial year found that the availability cost was relatively insensitive to input costs.[34] With the cost relatively constant, the main determinant of the margin values becomes the forecast balancing price. When calculating the availability payment in these circumstances, the margin values mechanism will tend to over-recover availability cost over the course of a year if the forecast

[34] EY, 2019, *Ancillary Services Parameter Review 2019 Final Report, Public version*, (online), p. 69

balancing price was under-estimated and then under recover if the balancing price was over-estimated.

An alternative would be to mathematically estimate the margin values that would be necessary to provide appropriate compensation for spinning reserve. However, this would also be sensitive to any disconnection between the forecast balancing price and actual future balancing prices.

In October 2022, the market is scheduled to adopt a market-based mechanism for ancillary service price setting. [35] The ERA's 2021/22 determination will cease before the scheduled changeover to the new market. An additional process may be needed to bridge the gap between the current framework and the commencement of the new ancillary services market.

Questions

The modelling indicates substantial changes to the cost of spinning reserve and load rejection reserve, and the derived ancillary service parameters may not provide adequate compensation for spinning reserve. With a comparable magnitude in total of spinning reserve and load rejection reserve, is there a case to roll over the 2020/21 values?

What alternatives could ensure correct compensation is paid in 2021/22?

4. System restart

System restart is the ancillary service that pays generators capable of re-energising the electricity system or parts of the electricity system that have been subject to a full blackout. A diversity of system restart services is needed across the network to ensure the system can be re-energised if a particular black start provider fails, or where parts of the network become physically isolated – such as through a bushfire or storm.

AEMO determined that it needed three service providers in geographically different parts of the network to provide for system recovery. These regions are:

- North Metropolitan
- South Metropolitan
- South Country.[36]

Generators providing system restart services are compensated through the R component of the Cost_LR parameter. System restart costs are borne by market customers based on each share of electricity consumption.[37]

When entering an ancillary services contract, AEMO must:[38]

- Seek to minimise the cost of meeting its ancillary service requirements.
- Consider a competitive tender process unless it would not minimise the cost of ancillary services to the market.
- Report to the ERA the capacity, prices, and terms for calling on the contracted facility to provide the restart capacity.

The ERA reviews AEMO's proposed system restart costs against the market rule requirements and determines system restart parameters consistent with the market rules. The market rules allow contract costs to exceed the efficient costs of system restart. Although the ERA seeks to identify and approve only efficient system restart parameters, AEMO can recover the full contract cost through the shortfall mechanism. This is a situation where the market rules appear inconsistent with the market objectives.

AEMO previously entered into contracts with Synergy for services in the North Metropolitan (Pinjar units 3 and 5) and South Country (Kemerton GT11 and GT12) areas, and with Perth Energy to service the South Metropolitan area.[39] The South Country contract runs until 23 October 2028 and comprises most of the total proposed system restart cost.

The North and South Metropolitan contracts are due to expire on 30 June 2021. AEMO is in the process of procuring new system restart service contracts for these areas.

[36] ERA, 2020, *Decision on the Australian Energy Market Operator's 2020/21 Ancillary Services requirement* (online) and ERA, 2020, *Approval of revised 2020/21 LFAS Ancillary Service Requirement,* (online)

[37] Wholesale Electricity Market Rules, 1 February 2021, Rule 9.9.1 (online)

[38] Ibid, clause 3.11.9(a), 3.11.9(b), and 3.11.10

[39] ERA, 2020, *Decision on the Australian Energy Market Operator's 2020/21 Ancillary Services requirement*, (online), p. 9

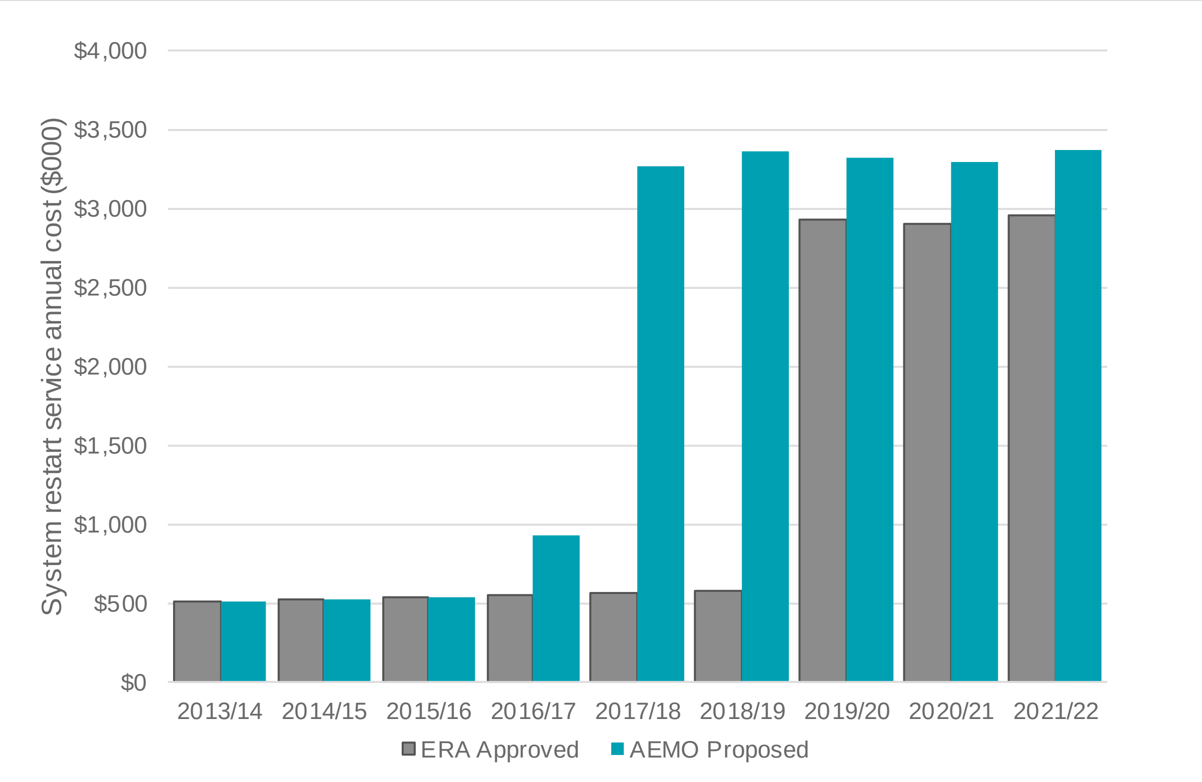
4.1 The ERA's past findings and recommendations

The 2020 review of system restart pricing concluded that there were material challenges to using competitive processes to procure system restart services. The 2020/21 determination found:

> Competitive procurement is particularly challenging in the WEM because the system restart market is highly concentrated and further restricted by dividing the network into sub-regions.
>
> …
>
> AEMO's current procurement approach meets the WEM objective of ensuring security and reliability of the system, but not the objective of minimising the long-term cost to consumers.

The ERA has not approved the full amount of AEMO's proposed system restart costs since 2016 (Figure 5).[40]

Figure 5: Historical proposed and approved system restart service values



Source: ERA determinations and AEMO

The step in the chart in 2016/17 is due to the ERA determining efficient costs lower than those proposed by AEMO. After examining the documentation and the financial model for the North Metropolitan contract in its 2020/21 determination, the ERA found that some of the tendered costs were inconsistent with the cost of providing the system restart service.[41] The ERA found that the tendered price included adjustments to ensure the whole generator received a

[40] ERA, 2016, *Determination of the Ancillary Service Cost_LR Parameters from 2016/17 to 2018/19*, (online), pp. 8-9

[41] ERA, 2020, *Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21 – Determination*, (online), p. 26

commercial return on investment rather than just the elements necessary for system restart. This transferred some costs arising from the risk of participating in the wholesale market onto the system restart service. The ERA considered that this was inconsistent with the market objectives.

In its 2020/21 determination, the ERA suggested measures to assist AEMO to increase the pool of suppliers and ensure that the quoted price better reflects the service provided.[42]

The ERA's suggestions included:

- Reviewing the procurement process and prescriptive requirements to make it more outcome focussed and encouraging a wider range of parties to participate.
- Requiring an itemised cost breakdown of tendered costs to limit tenderers from seeking to recover costs for unrelated infrastructure, market participation risks and other factors not directly linked to the provision of a black start service.

AEMO responded to the suggestions on system restart in its review of the black start technical requirements. In December 2019, AEMO issued an expression of interest for providers in the North and South Metropolitan areas without prescriptive requirements on how the service should be met.[43] Interested parties were invited to participate in a tender process; however AEMO is yet to award new service contracts. While the documentation is still to be provided and reviewed, the prices indicate the costs for the new arrangements to be consistent with pricing prior to that proposed in 2016.

4.2 AEMO's proposal

AEMO's proposed values for system restart service in the North and South Metropolitan areas are based on new contracts that are still under negotiation. Initial information provided by AEMO suggested the new contracts will be less expensive than the current contracts for these two areas. The ERA is still to examine the tender proposals themselves and contracts are understood not to have been let. The proposed value for system restart in 2021/22 is $3,369,438. This includes new contract costs for the North and South Metropolitan areas and the system restart costs from the existing service contract for the South Country area.

Questions

How can the procurement of system restart services be made more attractive or less onerous for participants?

How is the shortfall charge viewed in the market?

What alternative structures might improve governance of the system restart service? For example, would identifying the contract values be beneficial to the market and future procurement exercises?

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42 ERA, 2020, *Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21*, (online), pp. 29-30

43 AEMO 2019, *Request for Expressions of Interest – System Restart Service – Wholesale Electricity Market*, (online)

Appendix 1 The ERA's modelling exercise

ERA modelling rationale

The ERA has developed the agency's in-house modelling capability to support its functions in the wholesale electricity market including improving the quality of information available to inform decision-making on administered market mechanisms and in conducting market surveillance activities. This has included purchasing licenses for the PLEXOS modelling software.

Modelling process

The information collected for the ERA's market surveillance function was adapted as an input to a market model run on PLEXOS electricity market modelling software.[44] The inputs of market participants' generators were provided to the participants for review before final modelling.

The ERA undertook a back-casting exercise in advance of the forecasting process to determine the market model's suitability to model the WEM. Back-casting is conducted as a comparison between the modelled market and real market to validate that the model is performing properly and producing results analogous to the real market.

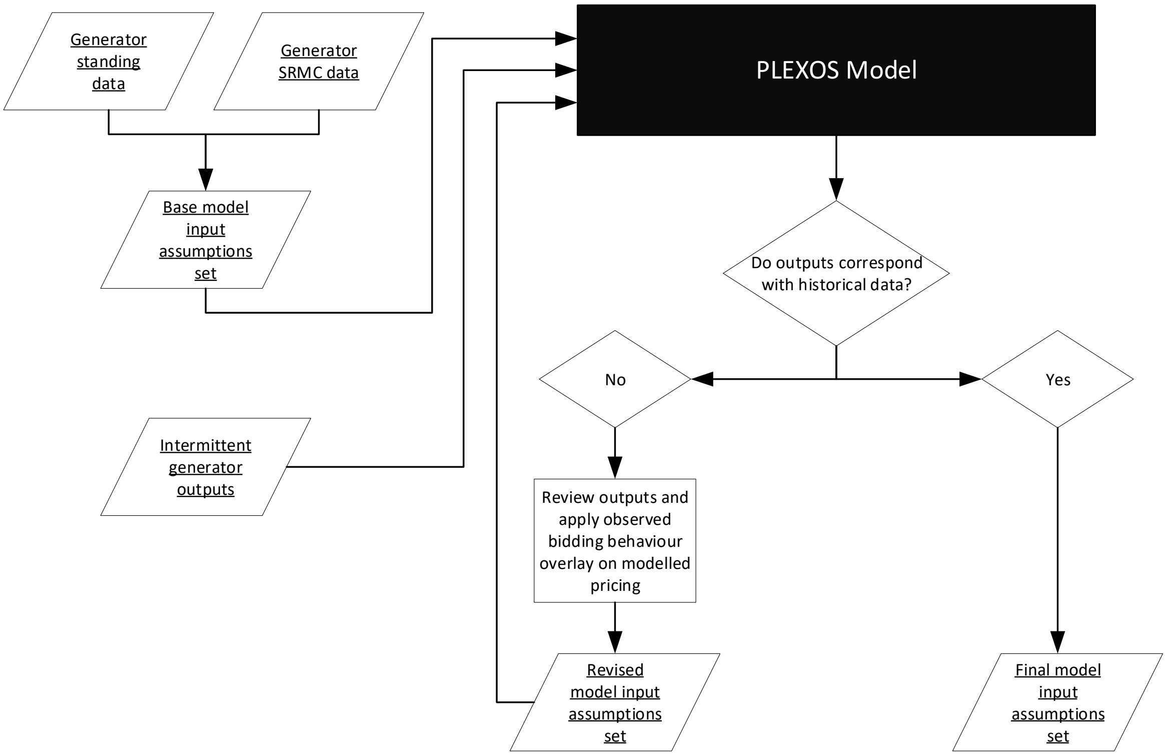
Back-casting exercise

The 2019/20 financial year was the back-casting reference year. This year was chosen as it was the most recent complete financial year to the forecast period. Scheduled generators were modelled using information collected from generators for the base input assumptions and market participant standing data. Incremental steps were fitted to heat rate curves provided by market participants from which PLEXOS derived marginal heat rates for cost-based dispatch simulation.

The back-casting process is outlined in Figure 6 below.

[44] Wholesale Electricity Market Rules, 1 February 2021, Rule 2.16 (online)

Figure 6: Back-cast process



The calibration process included:

- Reviewing generator standing data and information collected under market rule 2.16 for generator short run marginal cost monitoring.
- Reviewing market bidding behaviour of offered quantities and prices by generators.
- Comparing generator dispatch outcomes in the real world with modelled outputs.

Market participants were provided with the assumptions books to review and were asked to confirm or correct the data for each generator. Some market participants responded too late to feature in the issues paper but will be included in revised modelling used to inform the final determination.

Scheduled generators only were modelled for the back-casting period. Non-scheduled generators, assumed to be price takers, were not modelled. The actual outputs for these generators were used for the back-casting period.

Table 3: Back-casting modelling exercises

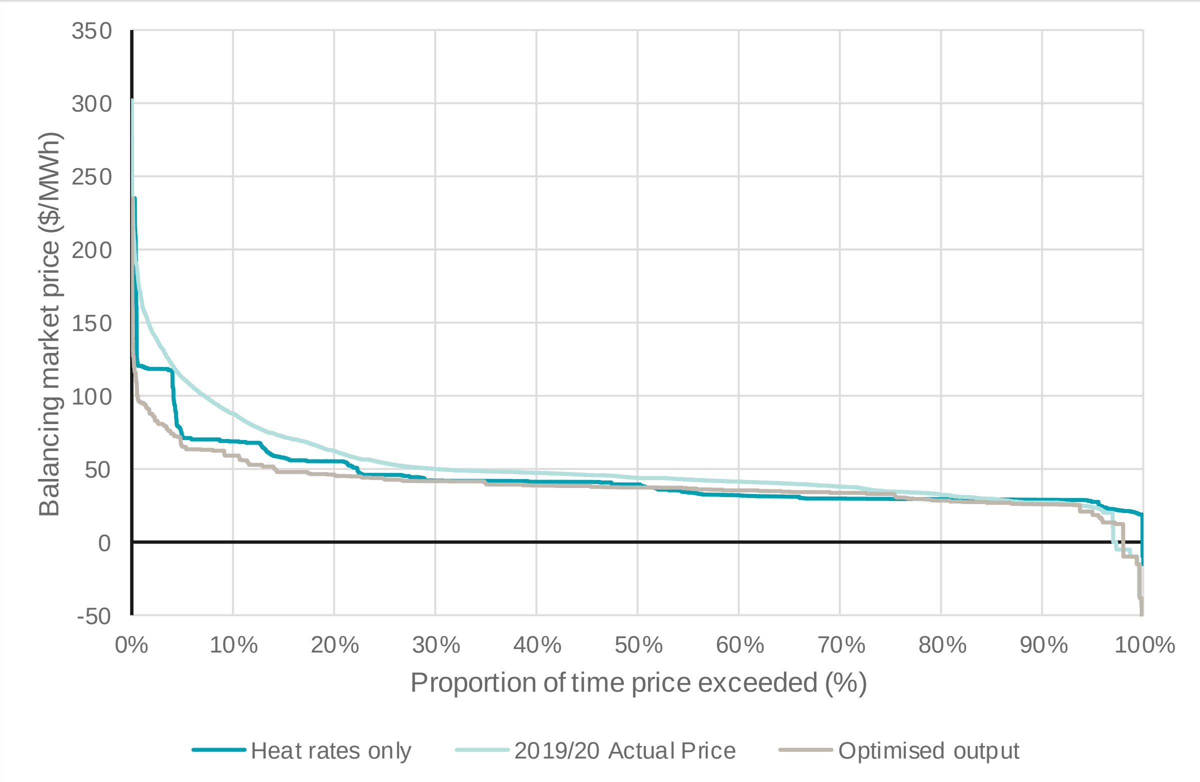
Back-casting runs	Description
Base data	This exercise used generator pricing information, characteristics in generator standing data, and data from SRMC information collection under market rule 2.16.

Back-casting runs	Description
Optimised data	This exercise applied mark-ups (cost multipliers) to emulate the bidding behaviour of generators. For example, these might reflect: • Costs unknown to the ERA that a generator may incur, such as changes in the maintenance costs of a generator. • Generation capacity that while available, is withdrawn to the market cap or high cost short term fuel supply arrangements not declared in the short run marginal cost information provided to the ERA.

By necessity, a model is a simplification of the real world and there will inevitably be differences between the modelled and real outcomes. The ERA has reviewed several aspects of the modelling to satisfy itself that the model is performing properly. Validation was conducted by testing the correlation between modelled and actual dispatch patterns for individual generators and across classes of generator.

The back-casting process delivered a good match with plant dispatch but tended to under-estimate prices. Figure 7 below shows the difference in the modelled and actual prices. This is explored in the later section titled Differences between the model and the WEM. The ERA will continue to refine its modelling to ensure a high degree of confidence in the forecasts used to inform the final determination.

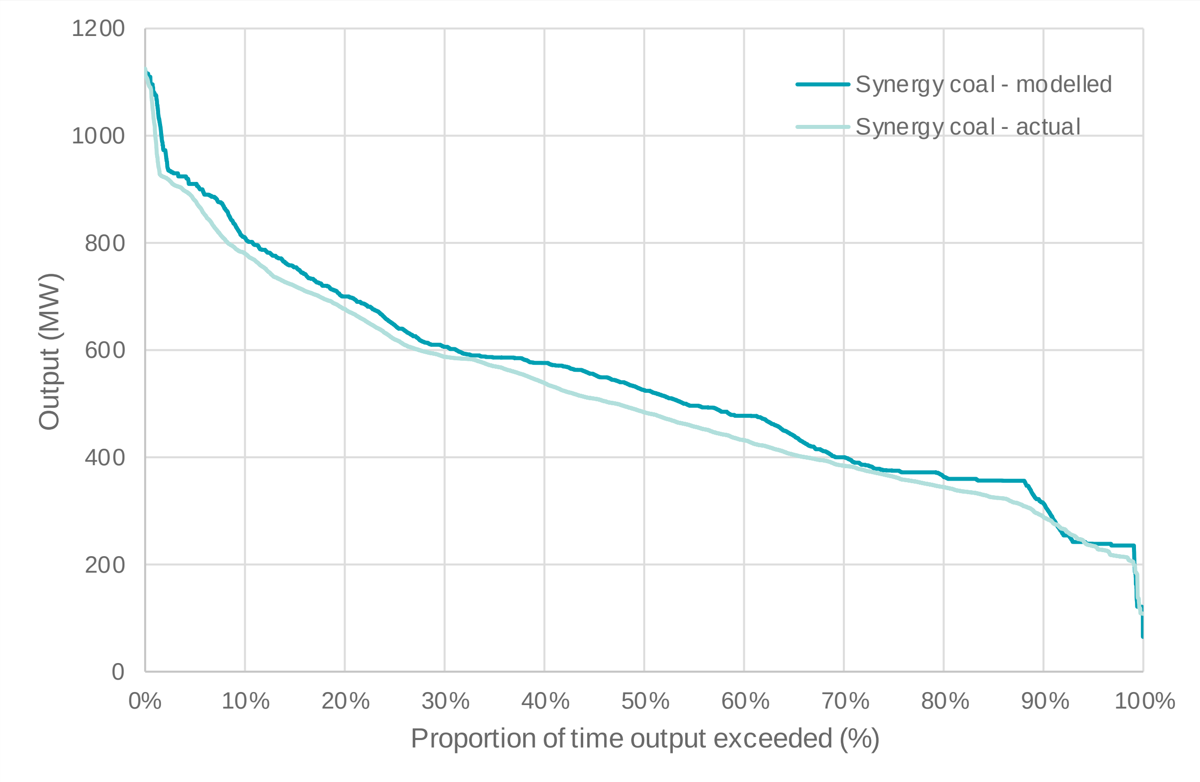
Figure 7: Price duration curves for heat rates only and post optimised back cast



Source: ERA modelling and ERA analysis of AEMO data

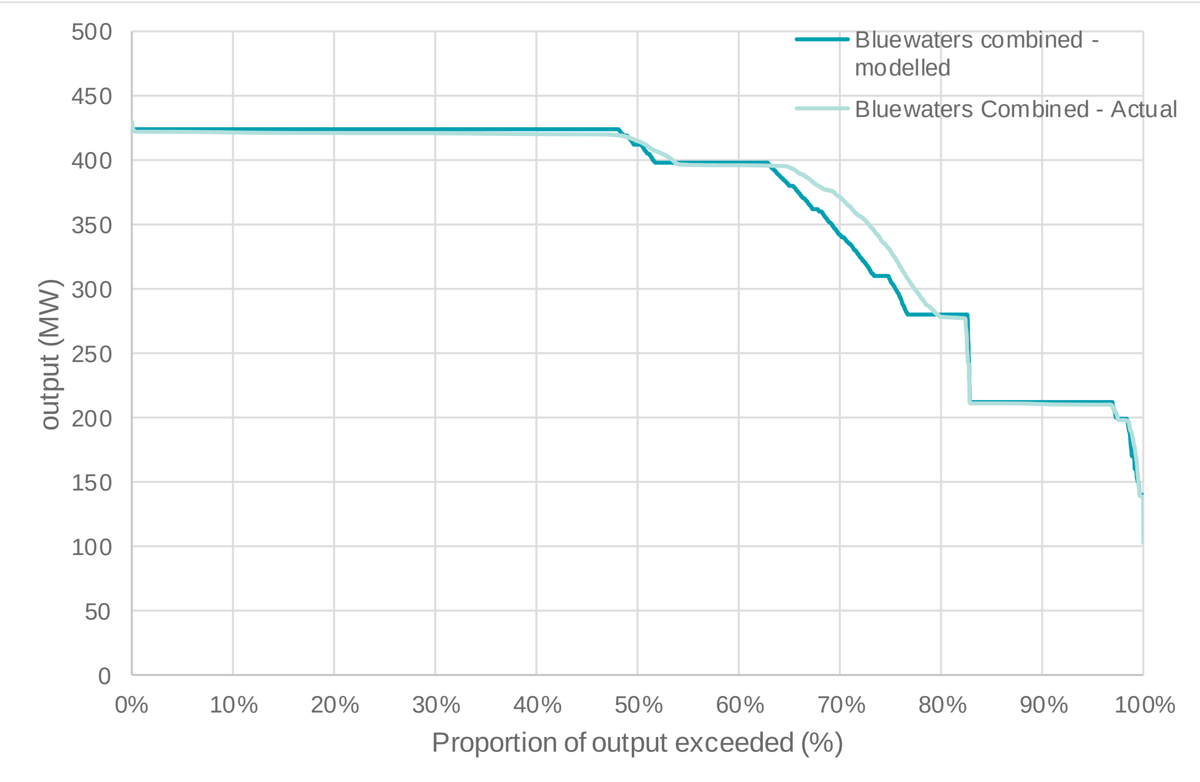
The charts below (Figure 8 to Figure 18) show output duration curves for major market generators for the back-casting period against the actual generator output.

Figure 8: Output duration curve for Synergy coal portfolio – modelled and actual 2019/20



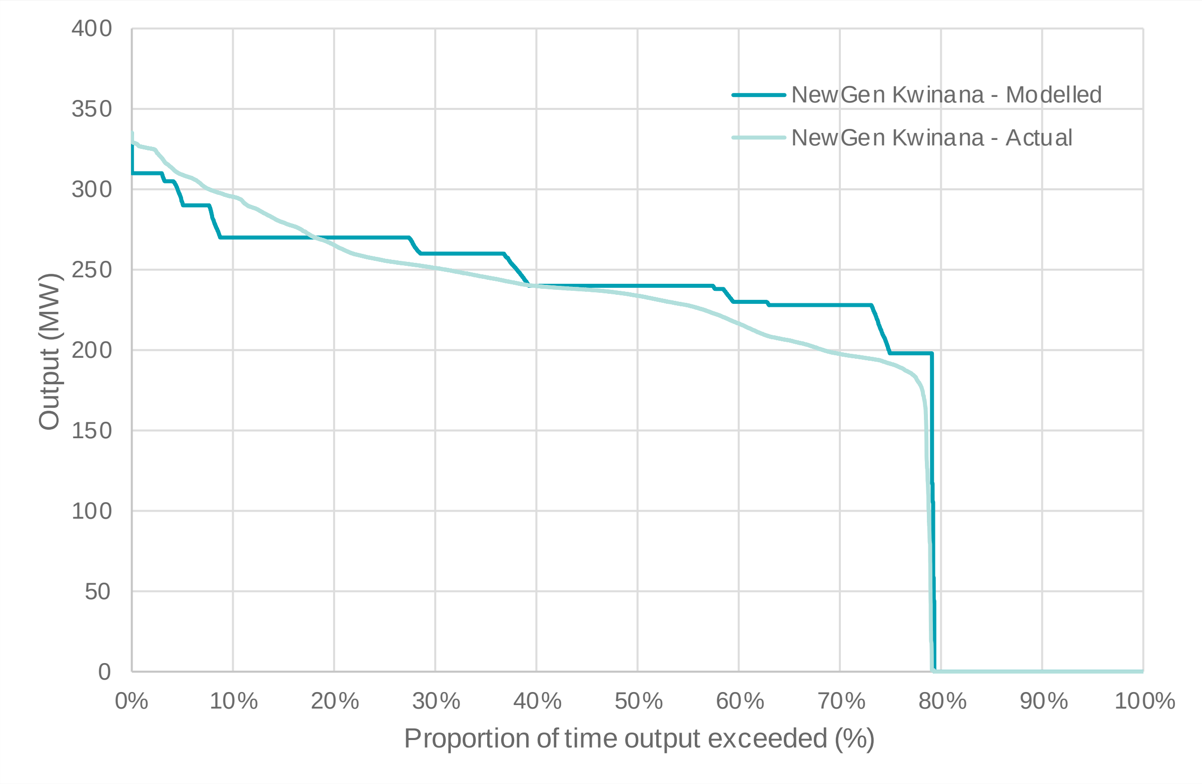
Source: ERA modelling and ERA analysis of AEMO data

Figure 9: Output duration curve for Bluewaters G1 and G2 – modelled and actual 2019/20



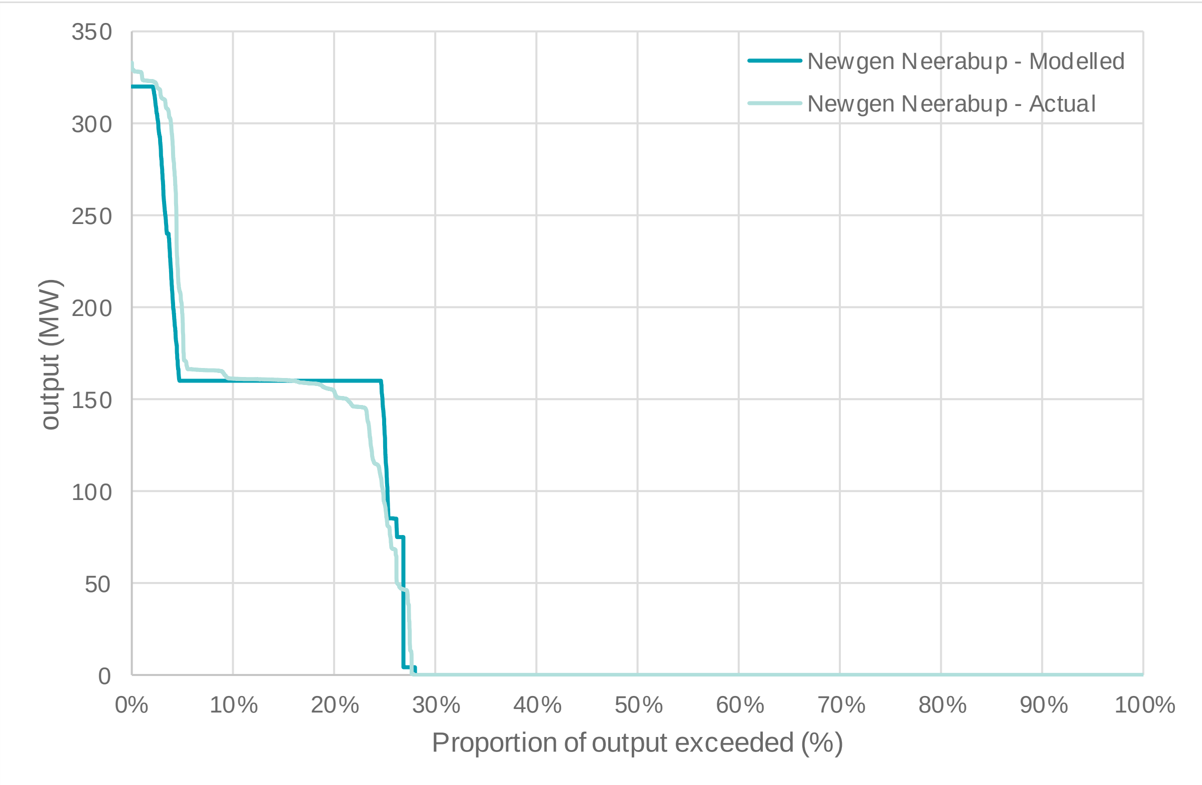
Source: ERA modelling and ERA analysis of AEMO data

Figure 10: Output duration curve for Newgen Kwinana – modelled and actual 2019/20



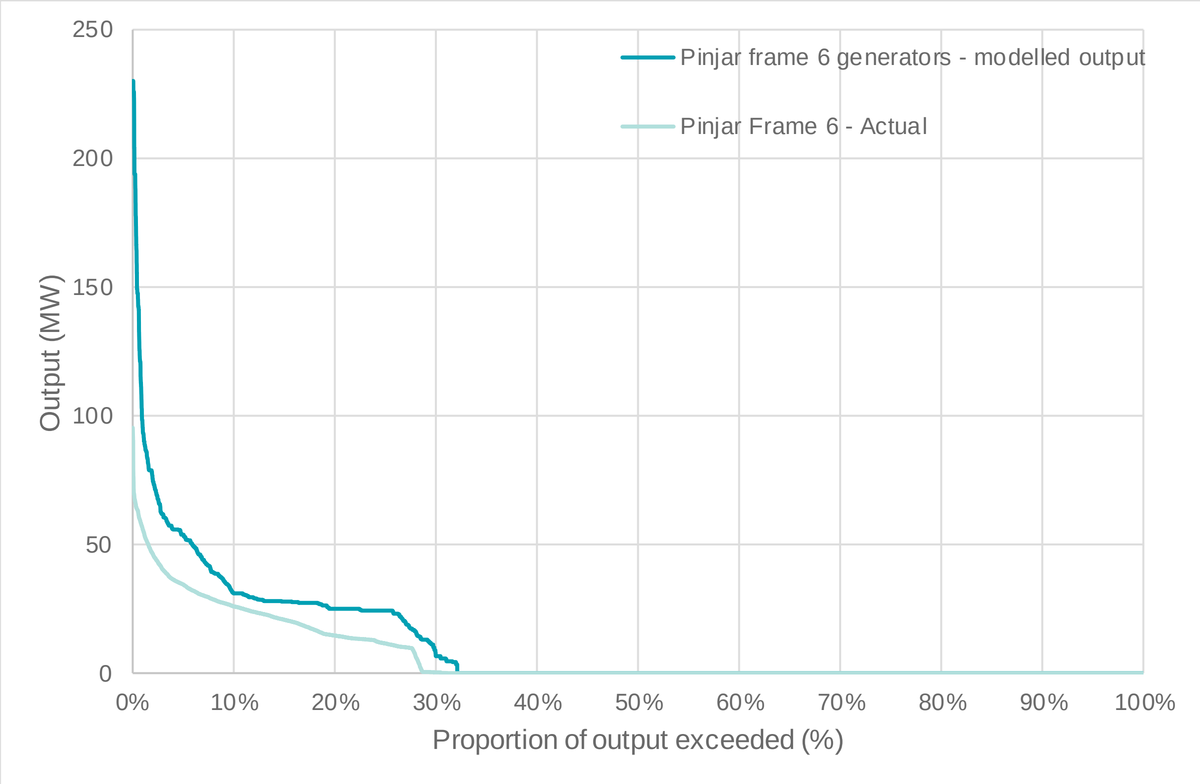
Source: ERA modelling and ERA analysis of AEMO data

Figure 11: Output duration curve for NewGen Neerabup – Modelled and actual 2019/20



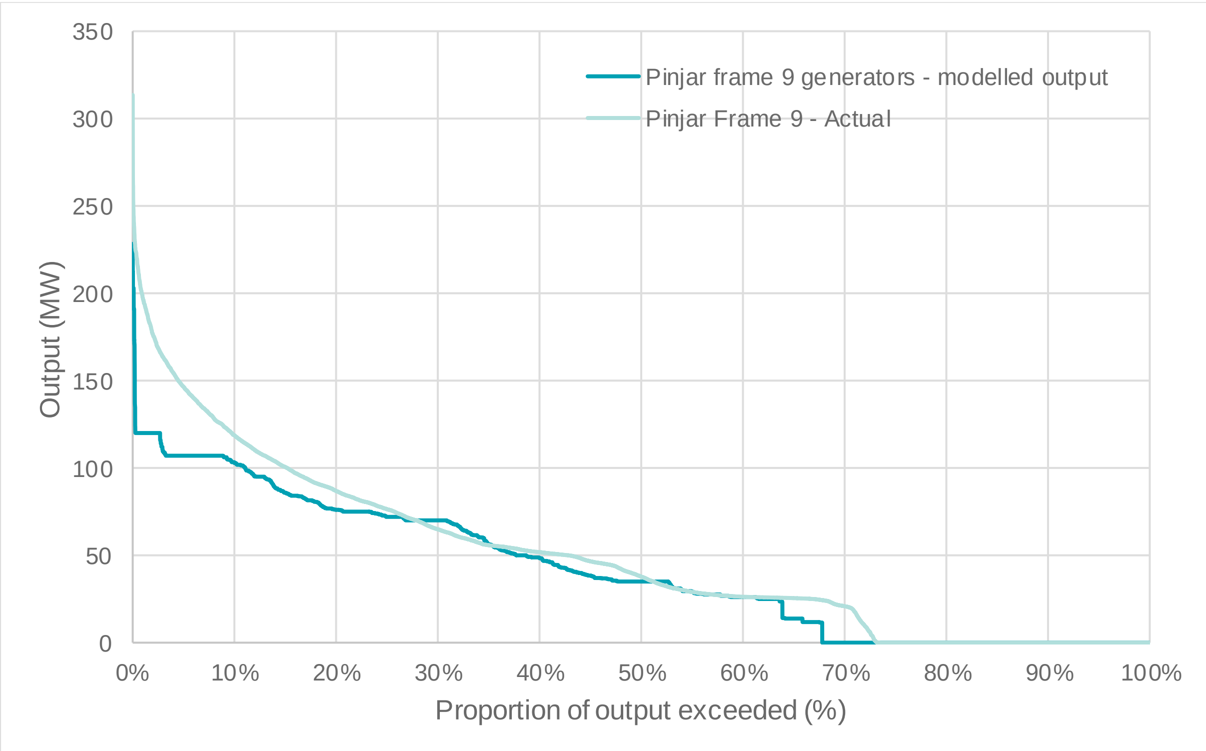
Source: ERA modelling and ERA analysis of AEMO data

Figure 12: Output duration curve for Pinjar frame 6 generators (GT1, GT2, GT3, GT4, GT5, GT7) – modelled and actual 2019/20



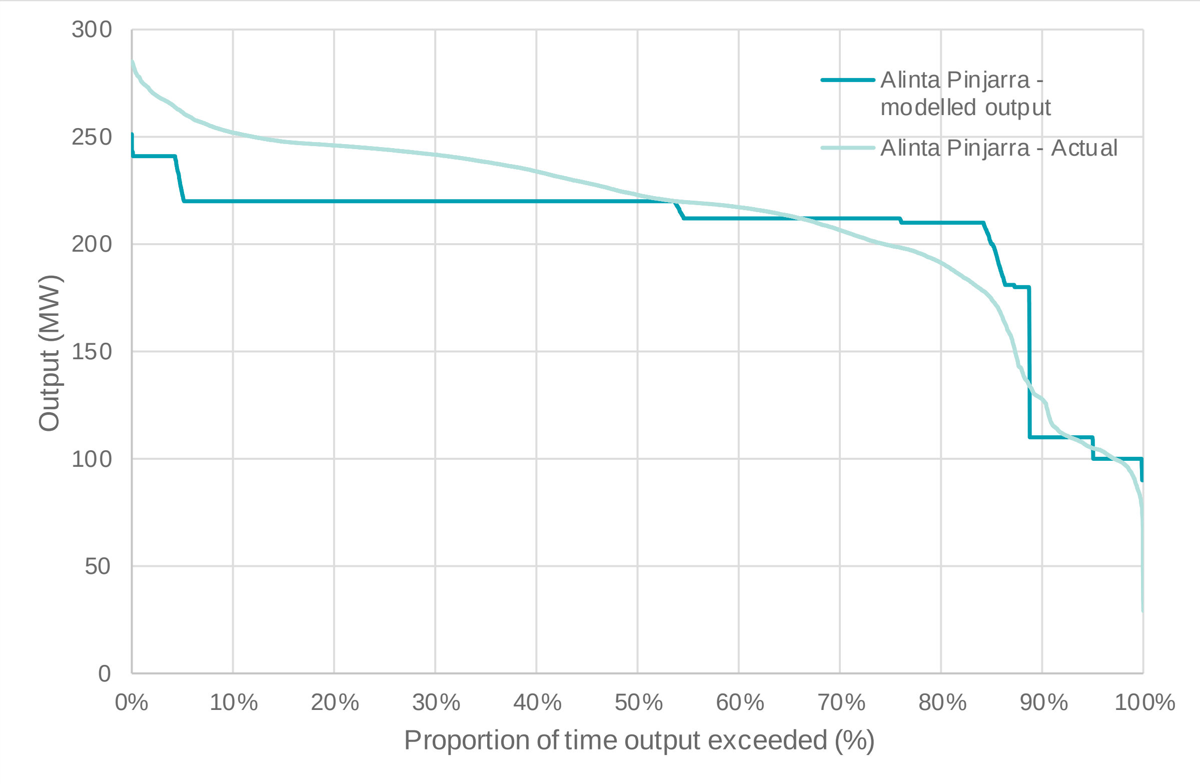
Source: ERA modelling and ERA analysis of AEMO data

Figure 13: Output duration curve Pinjar frame 9 generators (GT9, GT10, GT11) – modelled and actual 2019/20



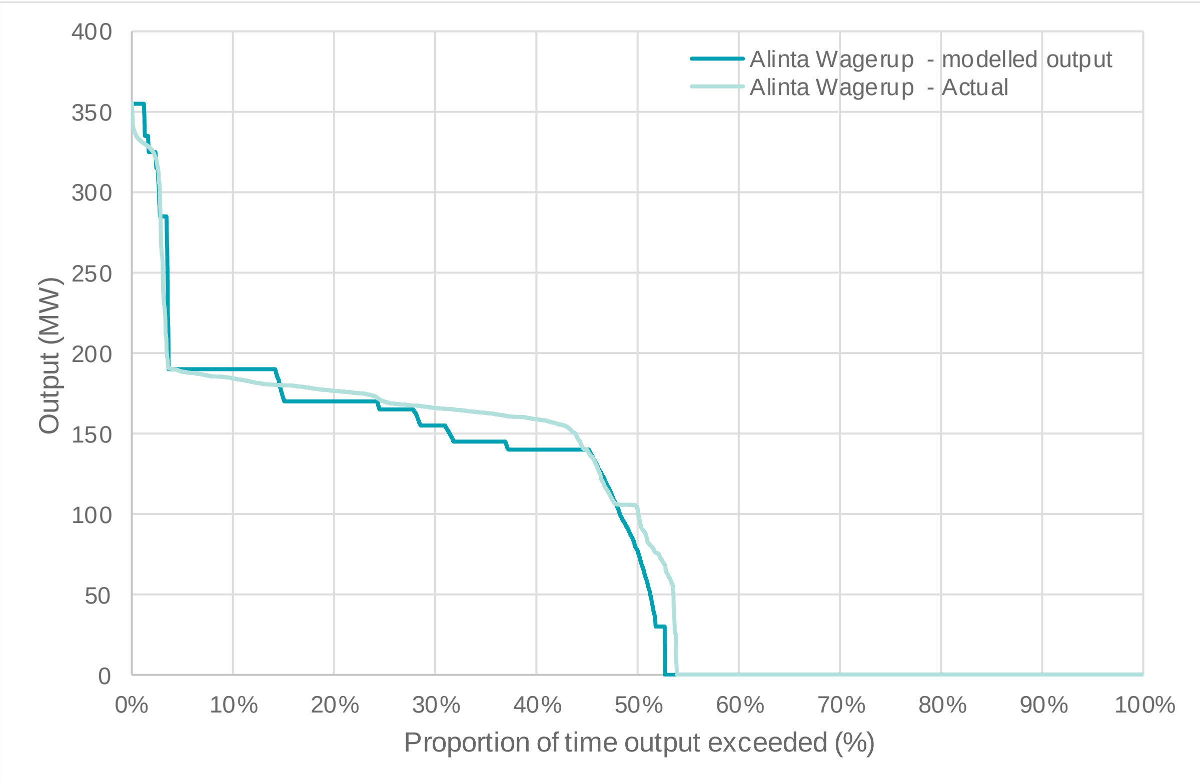
Source: ERA modelling and ERA analysis of AEMO data

Figure 14: Output duration curve for Alinta Pinjarra (U1, U2) – modelled and actual 2019/20



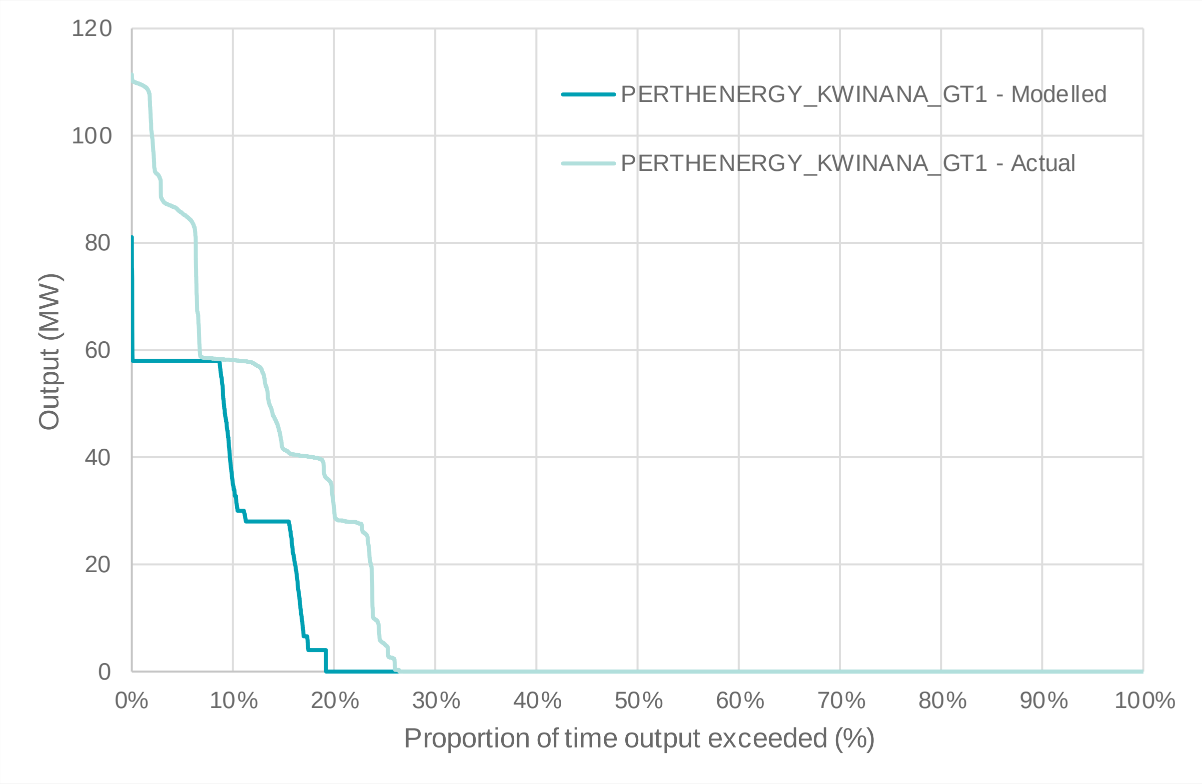
Source: ERA modelling and ERA analysis of AEMO data

Figure 15: Output duration curve for Alinta Wagerup (U1, U2) – modelled and actual 2019/20



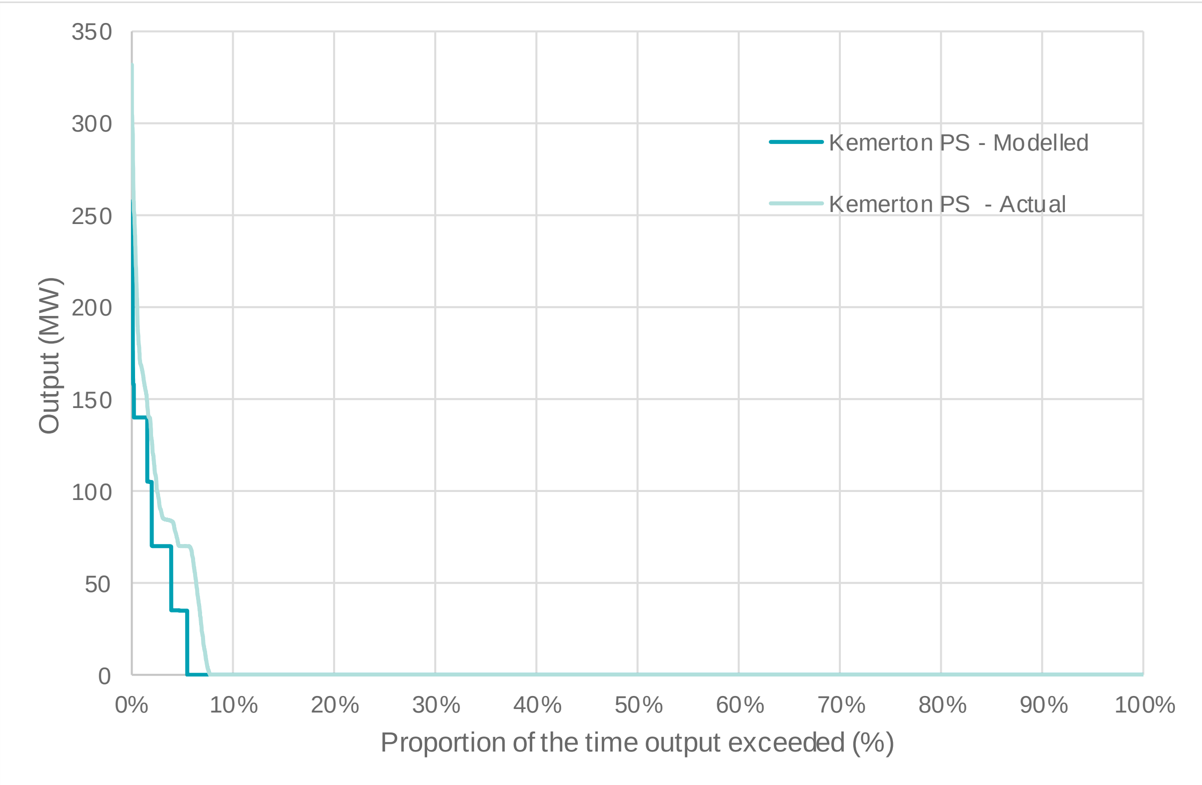
Source: ERA modelling and ERA analysis of AEMO data

Figure 16: Output duration curve Perth Energy Kwinana Swift – modelled and actual 2019/20



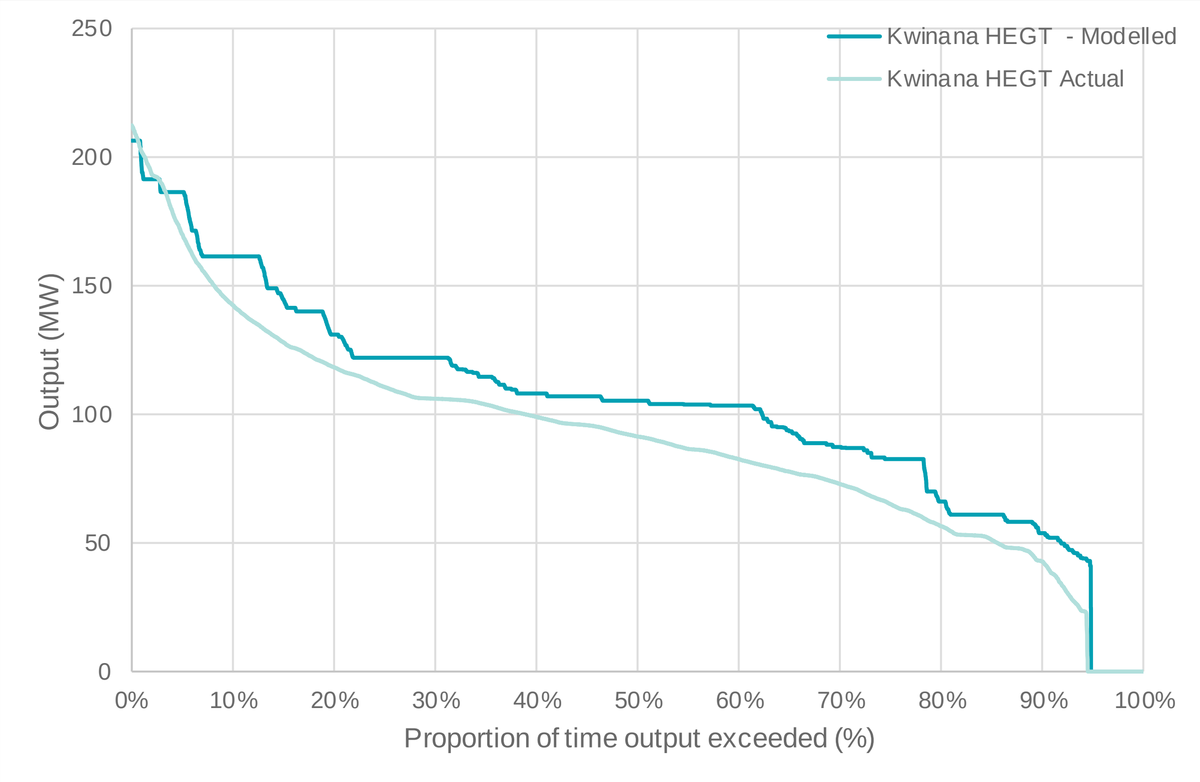
Source: ERA modelling and ERA analysis of AEMO data

Figure 17: Output duration curve for Kemerton – modelled and actual 2019/20



Source: ERA modelling and ERA analysis of AEMO data

Figure 18: Output duration curve for Kwinana HEGT– modelled and actual 2019/20



Source: ERA modelling and ERA analysis of AEMO data

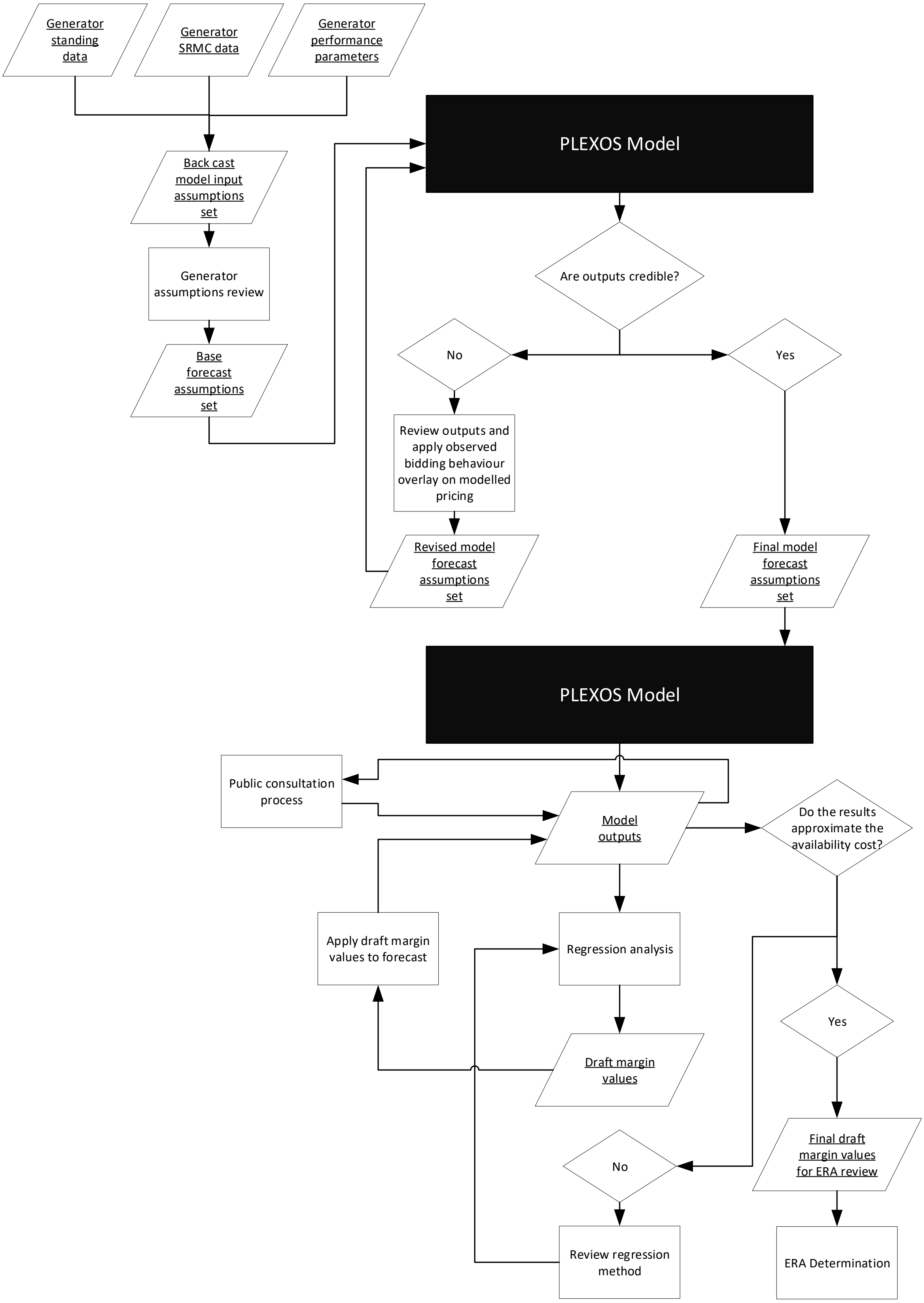
Forecasting process

The forecasting exercise was conducted on a similar basis to the back-casting exercise. It used fundamentally the same inputs but with profiles for new renewable generators and a different load profile. Electricity load profiles were scaled using the expected outcomes and a 50 per cent probability of exceedance modelled by AEMO from the latest electricity statement of opportunities.[45] The forecasts used the base model assumptions prepared following the back-casting exercises, the inclusion or exclusion of third party spinning reserve providers, and estimated wind outputs scaled to account for the GIA constraints.

The ERA's process is outlined in Figure 19 below. The back-casting process has been completed and provides the basis for the forecasting period. The ERA will refine the modelling to incorporate the views of market participants following the consultation process.

45 AEMO, 2020, *2020 Electricity Statement of Opportunities: A report for the Wholesale Electricity Market*, (online), pp. 3-8

Figure 19: Modelling and decision-making process



From the back-casting runs, the price matching is improved with the model configured to solely run on the heat rates alone or without output mark-ups. Similar to the back-casting runs, the generator outputs were not considered ideal to reliably forecast the ancillary services cost.

The model outputs indicated very low margin values. Under such circumstances, it was not considered likely the contracts would remain in place without revenue. Consequently, additional scenarios were run without contracted spinning reserve provision.

Reviews of the output of the generators also flagged a difference in the outputs of the new GIA generators. The non-scheduled generators were fixed inputs to the model based on estimated output profiles based on historical data where it exists and online output profile estimators based on the geographic location, turbine type and hub height. The output profiles were transformed using the actual data outputs and the extent to which the two wind farms in question have been constrained. Additional data is being sought from Western Power to better inform this.

Table 4 Modelling outputs by scenario

Parameter		With contracted Spinning Reserve			Without contracted Spinning Reserve		
		Heat rates	Optimised	Optimised wind	Heat rates	Optimised	Optimised wind
Balancing market Price ($/MWh)	Peak	31.04	13.56	18.33	30.51	13.81	15.92
	Off-peak	28.84	19.60	25.25	28.73	19.83	24.74
Availability cost – SR ($)	Peak	617,022	34,334	33,037	820,056	93,272	77,835
	Off-peak	235,264	15,529	47,265	432,669	74,529	89,640
	Total	852,286	49,863	80,302	1,252,725	167,801	167,475
SR requirement (MW)	Peak	191.4	171.1	171.9	195.1	170	171
	Off-peak	172.8	160.5	163.6	163.8	158.6	161
Margin Values (%)	Peak	0.0027	2.60×10^{-16}	1.38×10^{-17}	0.0104	5.73×10^{-17}	9.47x10-17
	Off-peak	0.0026	5.79×10^{-16}	3.85×10^{-16}	0.0093	8.42x10-16	9.50x10-16
Availability Cost – LRR ($)	Peak	3,348,920	5,368,533	6,075,773	2,768,872	6,803,446	6,154,000
	Off-peak	2,132,773	3,862,371	2,540,610	1,918,530	3,861,816	2,612,799
	Total	5,481,693	9,230,904	8,616,383	4,687,402	10,665,262	8,766,799

Source: ERA modelling

Quality assurance

The ERA has applied the following quality assurance steps to ensure the model is robust, the simplifications are understood by market participants, and that reasonable processes are driving modelling outcomes.

Table 5: Quality assurance steps

	Modelling element	Quality assurance processes applied
Model input assumptions	Cost parameters such as fuel and maintenance costs.	Model inputs were derived from regular updates market participants provide under market rule 2.16. The inputs reflect the main elements of a generator's short run marginal cost.
	Generator physical parameters.	Standing data was used to derive generators' physical parameters such as ramp rates, installed capacity and minimum stable generation.
	Operational performance.	Generator bidding practices were reviewed. Synergy's dispatch guidelines were also reviewed to assess whether it could be incorporated into the modelled generator performance characteristics.[46] .
	Market participant review.	Market participants received data for each generator to check the suitability of the back-casting input assumptions into the forecasting model.
Model outputs	Generator outputs.	Modelled generator outputs were compared against real world outputs for a twelve-month period through a back-casting process. Outputs were also examined to ensure the generator outputs were tolerably close to actual market dispatch.
	Calculation of ancillary service parameters.	The derivation of the ancillary services costs from the modelled outputs were independently calculated by two different teams to ensure the process was consistent with the underlying principles and the market rules. The regression analysis to derive the margin values will be subject to additional testing before the final determination.

Differences between the model and the WEM

The back-casting model under-estimated balancing market prices for the top 25 per cent of the price duration curve. It is expected that elements of this will have carried forward to the forecasting exercise. While some difference between the two is expected and normal for a model, there are elements of the pricing outcomes that will receive additional focus and refinement to inform the final determination.

This section explores possible reasons why the back-casting and forecasting process may be too low and possible remedies within the scope of this exercise being explored by the ERA as it refines its modelling for the final determination.

Elements within the scope of this exercise are discussed below.

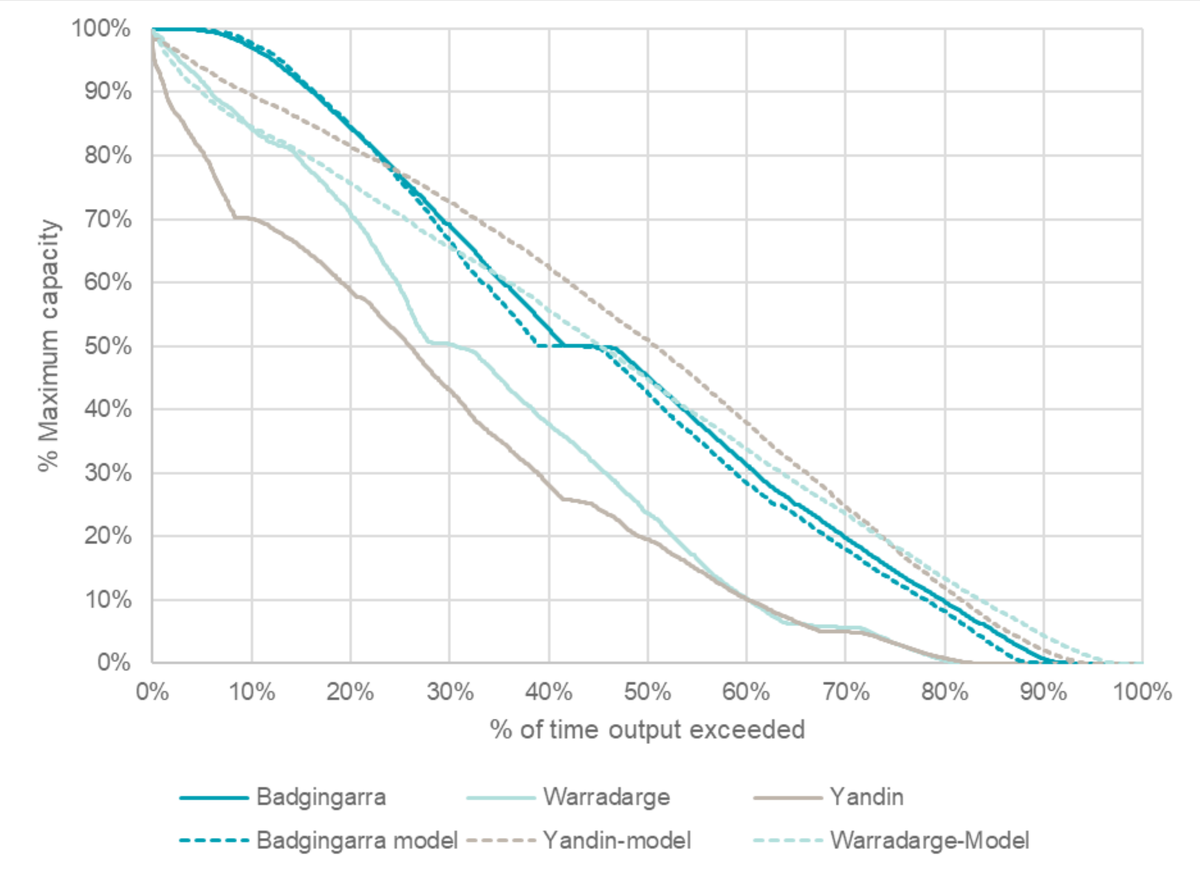
Operation of the Generator Interim Access constraints tool

Many of the newer wind farms operating under the generator interim access arrangement (GIA) have been operating for less than one year. The resource data estimate does not

46 Some assumptions were amended to reflect the guidelines but most were not able to be incorporated as the assumptions required a model with foresight on outcomes in the scheduling decisions.

account for the operation of the GIA tool for Yandin or Warradarge. In many of the scenarios the wind output may be over-estimated, reducing the forecast balancing price. Figure 20 below shows the model inputs for the three GIA generators (Badgingarra, Yandin and Warradarge) and the actual historical output profiles.

Figure 20: Outputs for wind farms connected under the generator interim access provisions



Source: ERA and ERA analysis of AEMO data

Additional information is being sought from Western Power on the operation of the GIA tool and how best to integrate it into the model. In the interim, a transformation on the input files for the two wind farms was input to the model.[47] Analysis of the few concurrent operating months of these wind farms indicates a relatively strong output correlation between them suggesting the outputs may naturally be similar or the operation of the GIA tool has a similar effect on curtailment.

Participant bidding behaviour

The back-casting exercise included a review of the bidding behaviour of market participants and 'mark ups' to load points in some market participants' supply curves were applied to better reflect cost and dispatch. This includes generation bid at the floor and at the market caps and intermediate steps for some generators. However, bidding strategies are dynamic and past behaviour may not be a good indicator of future market participation.

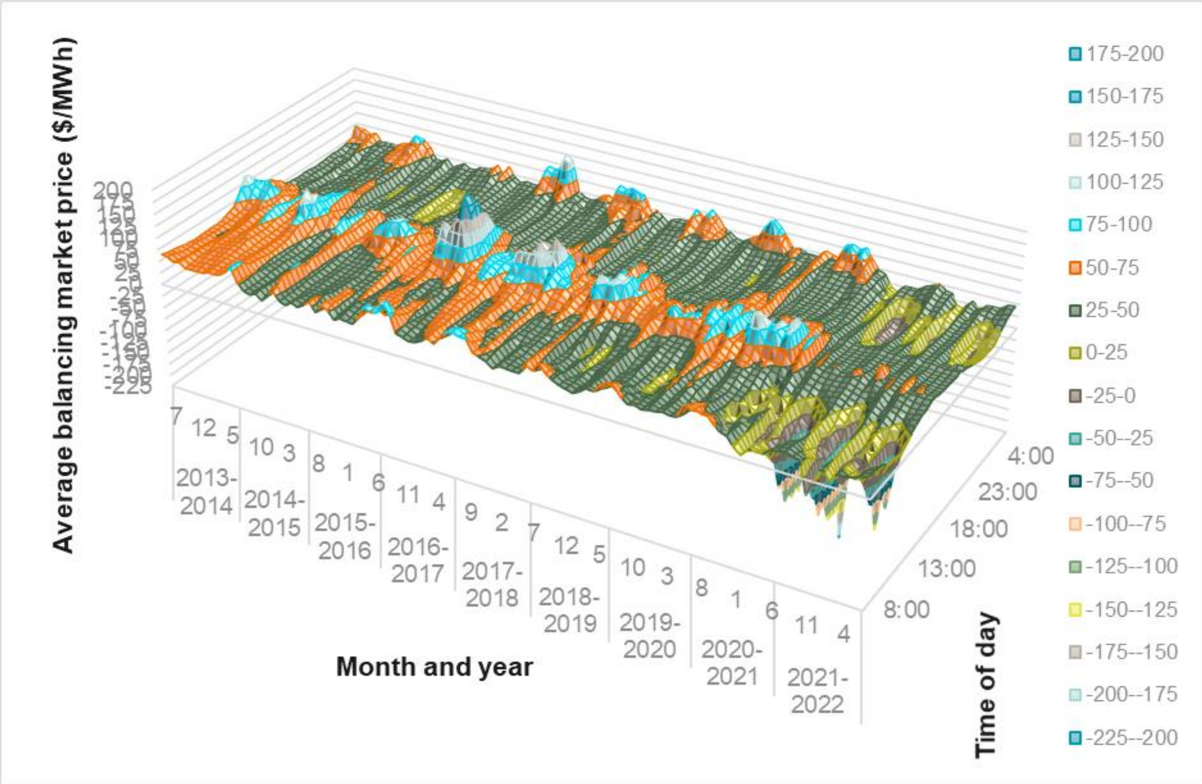
Figure 21 below shows the historical and forecast average monthly balancing market prices. Month and year are on the x axis, average monthly balancing market price is on the y axis and

[47] These are Yandin and Warradarge wind farms.

time of day is on the z axis. The pricing profile shows an increase in the frequency of negative day time and overnight pricing in the wholesale electricity market. Coupled with this is a reduction in the average afternoon ramp into evening prices.

There are some inflection points in the overall balancing market offer curves where the prices escalate to the price caps quite sharply. The increase in low marginal cost generation into the market coupled with the assumption that market participants continue pricing the same quantities of energy at the floor may not be realistic. Further modelling will be conducted exploring the reprofiling of bids below zero.

Figure 21: Historical and forecast average monthly balancing market prices



Source: ERA modelling and ERA analysis of AEMO data

Data currency

While all material market participants were provided copies of the input assumptions relevant to each generator, not all chose to respond and some responses arrived too late to be incorporated into the modelling described in this issues paper. The ERA will follow up with parties that declined to respond, particularly large parties, as the modelling is further refined to inform the final determination.

Elements outside the scope of this exercise

Manual scheduling

The WEM does not yet co-optimise energy and ancillary services. Energy dispatch and load following are independently optimised first, with other ancillary service reserves following. Also, Synergy operates a portfolio of generators where pricing bids are only indirectly connected with individual generators. Together, these two features of the WEM likely reduce the economic efficiency of the market. Past back-casting exercises such as those by third party consultants have tended to result in accurate dispatch modelling but with a divergence in pricing outcomes.[48]

Many of the manual interventions in the WEM are not possible to replicate in the model. For example, many of the scheduling decisions reflect the experience and risk aversion of individual control room operators. Another example is Synergy's dispatch guidelines which anticipate future market conditions in a manner challenging to replicate within the WEM model.

The PLEXOS model simultaneously co-optimises load rejection reserve, load following reserves, spinning reserve, and ready reserves to minimise cost across all services.[49] In the model, all generators are assumed to operate and bid as discrete generators.

Data availability

The model is run as a single node. There is not sufficient publicly available data on the load at individual nodes and the associated constraints to model network elements and associated constraints. However, loss factors for individual generators are applied.

Exercise of market power

Some of the price difference may also be a consequence of market participants exercising market power. There have been instances where market participants have priced in a manner inconsistent with the market rules.[50] The ERA is pursuing such a case before the Electricity Review Board.[51]

48 Ernst and Young, 2019, *Ancillary Services Parameter Review – 2019 Final Report*, (online), p. 36

49 Ready reserve is the ancillary service for fast-start generators to be available within fifteen minutes to cover 30 per cent of the total output of the generator with the highest total output synchronised to the SWIS. Wholesale Electricity Market Rules, 1 February 2021, clause 3.18.11A, (online)

50 ERA, 2014, *Investigations 1 and 2 on Vinalco Energy Pty Ltd*, (online)

51 ERA, 2017, *Investigation into Synergy's pricing behaviour*, (online)

Appendix 2 The ERA's review of AEMO's proposal

On 24 April 2020, AEMO advised the ERA that it would not undertake dedicated modelling for the 2021/22 spinning reserve and load rejection reserve proposal.[52]

The ERA has three concerns with AEMO's proposal that mean it may not provide a sufficiently sound basis to inform determination of the 2021/22 ancillary service parameters for spinning reserve and load rejection reserve.

The first concern is with some of AEMO's 2020/21 modelling assumptions. AEMO used back-casting to simultaneously set Synergy's gas price and calibrate the market simulation model. The ERA considered the gas price AEMO identified was unreasonable compared to publicly available gas price data. The ERA also expressed concern that AEMO applied the derived gas price to several generators by overwriting fuel price assumptions provided by market participants. AEMO also made changes to the coal price for both Synergy generators and Summit Southern Cross Power's generators. The scenarios included the following assumptions:

- Synergy's delivered gas price set at $3.50/GJ and market coal price increased
- Synergy's delivered gas price set at $5.25/GJ and market coal price increased
- Synergy's delivered gas price set at $6.50/GJ and market coal price increased.

The ERA's 2020/21 determination stated (emphasis added):

> The ERA does not support AEMO's base case modelling scenario. The Synergy gas price underpinning the scenario does not appear to have a justifiable basis nor does the method for its derivation. It was impractical to replicate or amend the modelling after AEMO submitted its proposal. Therefore, the ERA has considered the fuel price sensitivities as the basis for setting the margin values and load rejection reserve costs. The fuel price sensitivity using $5.25/GJ as a Synergy gas price input **is the closest of the three cases to what the ERA considers a reasonable and justifiable market cost** for gas that is supported by information from publicly available sources and the range of gas prices submitted by other market participants.

The determination reflected a limited choice where the ideal input assumptions were not available. Instead, to determine the values for 2020/21, the ERA selected outputs from the sensitivity analysis modelling in AEMO's proposal that were closest to the ERA's view of realistic modelling assumptions.[53]

At the time, the ERA did not have the capacity to undertake its own modelling to test a different set of input assumptions. Time constraints in the 2020/21 determination process meant that it was not possible for the ERA to replicate AEMO's proposal using assumptions that more closely reflected the market.[54]

The second concern is that current market conditions, as outlined in section 3.1.23, appear to be different to 2019 when the last modelling was conducted. The changes in market conditions will change the dispatch outcomes and the cost to provide the services.

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53 ERA, 2020, *Determination Report – Margin Values and Cost_LR Ancillary Service Parameters for 2020/21*, (online) pp. 9-16

54 Ibid, p. 15

The final concern is the changes in market conditions appear to be materially affecting the contingencies the market needs to cover as outlined in section 3.

Since receiving AEMO's proposal in June 2020, the ERA has invested in market simulation software, and developed a model of the WEM. This has allowed the ERA to assess AEMO's proposal against modelled ancillary service parameters and costs.