Spinning Reserve, Load Rejection Reserve and System Restart Costs: Margin Values and Cost_LR Ancillary Services parameters for 2020/21

Issues Paper

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Economic Regulation Authority

WESTERN AUSTRALIA

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Monday, 10 February 2020.

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

You can also send comments through:

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Post: PO Box 8469, PERTH BC WA 6849

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

Ancillary services are used by the Australian Energy Market Operator (AEMO) to maintain the security of the South West Interconnected System. The costs of these services are borne by market participants. Costs for three of the four services - spinning reserve, load rejection reserve and system restart – are calculated using an administered mechanism. The cost of the fourth service - load following, which helps to balance supply and demand in real time – is determined through a market mechanism.

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. Spinning reserve provides a rapid increase in generation to compensate for the sudden loss of a large generator or transmission equipment. Load rejection provides a rapid decrease in generation if a large load is lost.

A generator providing system restart can energise the electricity system after a total system blackout – often called a black start. AEMO enters into contracts with generators for system restart services.

As the largest generator in the Wholesale Electricity Market (WEM), Synergy is the default provider of ancillary services, including spinning reserve and load rejection reserve.[1] Payments to Synergy for providing these services are based on the settlement formulas prescribed in the market rules using values and parameters determined by the Economic Regulation Authority.[2]

AEMO proposes ancillary service parameters and values to the ERA for the three administered services: annually for spinning reserve, and every three years for load rejection reserve and system restart services. Synergy recoups its costs through the margin values for spinning reserve, the 'L' component of COST_LR for load rejection reserve, and the 'R' component of COST_LR for system restart service.

To determine the margin values parameters for spinning reserve, and costs for the load rejection reserve and system restart services, the ERA considers AEMO's proposal in the context of the WEM objectives.[3] The ERA also undertakes public consultation by publishing an issues paper and inviting public submissions.[4] The ERA must make its determination on the values to apply in 2020/21 by 31 March 2020.

This issues paper is intended to assist interested parties to make submissions on AEMO's proposed margin values and the costs of load rejection reserve and system restart costs for 2020/21. It is intended to be read in conjunction with AEMO's proposal and the supporting material.[5]

The timing of this process and the need to consult with industry over the New Year holiday period means that the ERA has prioritised releasing AEMO's proposal and this paper for comment prior to considering the proposal and the underlying modelling in detail. The ERA will review the modelling in parallel with industry consultation and reserves judgement on the proposal until it makes its determination.

1 Rule Change Panel, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 3.11.7A (online)

2 Ibid. clause 9.9.2(f)

3 Ibid. clause 1.2

4 Ibid. clause 3.13.3A(b)

5 Ancillary services parameter review 2019 final report (public version), and supporting data excel files, Ernst & Young (for AEMO), 6 December 2019 (online)

1.1 The determination in the context of reform

Spinning and load rejection reserves are scheduled to be replaced by essential system services as part of the Energy Transformation Strategy reforms in October 2022.[6] The proposed market design will simultaneously identify the lowest cost combination of generator offers to provide ancillary services, renamed essential services, needed to maintain system security. Excluding system restart costs, the cost of other essential services will be determined through the market mechanism.

Consequently, the ERA's annual approval of margin values and triennial approval of load rejection reserve costs will no longer be needed in the new market. System restart services will continue to be contracted, but the ongoing oversight and approval role, at present, is unclear.

Until the new market begins in October 2022, the current administered costing process applies in 2020/21 and 2021/22. The approved costs of spinning reserve and load rejection reserve have reduced over recent years from $14.69 million in 2017/18,[7,8] to $11.74 million in 2019/20 but the amounts are still significant for market participants.[9,10] In 2019/20, the indicative and approved costs were:

- spinning reserve - approximately $10.3 million
- load rejection reserve - $1.4 million
- system restart - $2.9 million.

The ERA is interested in understanding market participants' views on ancillary service costs over the next two financial years.

Questions

1. Given the reductions in spinning reserve and load rejection reserve costs, do market participants consider the values are still too high?
2. How should the effort to reduce costs further be considered in the remaining two years?

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6 Energy Policy WA, Taskforce publications webpage, (online), accessed on 10 December 2019.

7 Parotte, C, 2016, *Submission of proposed Margin Values for 2017-18*, (online), P. 1

8 ERA, 2016, *Determination of the Ancillary Service Cost_LR Parameters for 2016/17 to 2018/19*, (online), P. 1

9 Parotte C., 2019, *Submission of Proposed Margin Values for 2019/20*, (online), P. 1

10 ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)*, (online), P. 23

2. The modelling process

AEMO engaged Ernst & Young (EY) to undertake modelling to assist in calculating the margin values and Synergy's cost of providing the load rejection reserve for 2020/21.

The modelling seeks to identify the costs of delivering spinning reserve and load rejection reserve ancillary services in an efficient market. The model simulates future market outcomes including generator dispatch and balancing market prices. This process forecasts the spinning and load rejection reserve requirements used in the settlement equations and estimates the foregone margin necessary to compensate Synergy for providing the services. These values also inform AEMO's spinning reserve contracts with third parties.

AEMO's proposals and EY's public reports are available on the ERA website.[11] AEMO also provided the ERA with confidential EY reports on the calculation of margin values and load rejection reserve costs.

AEMO made changes to the modelling this year. These changes were in response to the ERA's recommendations in last year's determination and changes in the market. The changes were driven mostly by the increased penetration of renewable generation: solar generation installed on consumers' rooftops and new wind and solar farms connecting to the network. The changes to the modelling are outlined below.

2.1 ERA's past recommendations

The ERA has previously recommended ways that AEMO could improve the calculation of Synergy's opportunity cost of providing spinning reserve. EY has developed models consistent with these recommendations. The ERA's recommendations also influenced the calculation of load rejection reserve costs.

In its last determination (published March 2019), the ERA recommended that for all future reviews of ancillary services AEMO:[12]

- Ensured that all accompanying documentation (such as consultant reports) underlying its proposals contained a detailed discussion of the results, including reconciling modelled results with observed practice.
- Ensured that its consultants conducted sensitivity analyses prior to modelling and included a detailed discussion of the results in the draft assumptions report.
- Rigorously tested input assumptions for the model with market participants including using blank forms to collect modelling input data prior to conducting a back-casting analysis.
- Ensured that its consultants conducted back-casting analysis and used the results to validate the input assumptions.
- Ensured that its consultants included detailed discussion of results, and possible limitations of the modelling in the final assumptions report.
- Submitted all supporting information, including modelling output workbooks, together with its proposal, by 30 November each year.

11 https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin_peak-and-margin_off-peak

12 ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)*, (online), P. 12

- Ensured that a proper quality assurance process was conducted on the proposals and their supporting documentation, with supporting statements on how the quality assurance was conducted and any issues identified.

AEMO also sought to accommodate the ERA's suggested approach to collecting input assumptions using blank forms but was only partially successful in collecting a full set of assumptions for the modelling. This meant that AEMO had to estimate or otherwise derive some assumptions. The approach AEMO adopted for Synergy's gas price was to start with a figure of $6.50 per GJ delivered for gas, and then, through a back-casting exercise, adjust the gas price and other input parameters until the model dispatch outcomes closely matched historical generator dispatch.

Through this process, AEMO revised Synergy's estimated gas price downwards to $3.50 per GJ delivered. The weighted average domestic supply price (excluding transport) for domestic gas in 2018/19 was $4.05.[13] Market spot prices in November 2019 were between $2.44 per GJ and $2.74 per GJ with an average value of $2.57 per GJ.[14]

The gas price forms an important input assumption in ERA's determination, and the ERA is interested in stakeholders' views on the price.

Question

3. Do market participants consider a forecast gas price of $3.50 per GJ (delivered) to be a reasonable assumption? If not, why not? What would be a reasonable basis to determine the forecast price for gas?

2.2 Changes to the modelling approach

AEMO incorporated several changes into the modelling for its 2020/21 proposal. Some of these changes reflected changes in market design and others were modelling refinements. The changes influence how generators are dispatched in the model, which in turn affects the forecast quantity and cost of spinning reserve and load rejection reserve. The modelling changes are outlined below.

2.2.1 Market-driven changes

There are three main changes to the WEM that AEMO has captured in the modelling for spinning reserve and load rejection reserve for 2020/21.

The main changes are:

- Spinning reserve full runway cost allocation:
  - Blocks of spinning reserve costs were previously allocated to generators based on their output. Above certain thresholds, the share of spinning reserve liabilities

13 This price is calculated by the Department of Mines, Industry Regulation and Safety from gas producer royalty returns to government. It is derived from the sum of domestic gas sales revenue collected by producers and divided by the domestic gas production.
Department of Mines, Industry Regulation and Safety (2019) 2018-19 Major Commodities Resources File, DMIRS, Perth, online, Petroleum – Gas Prices tab.

14 Gas Trading, Historical Prices and Volumes webpage, online, accessed 5 December 2019.

increased substantially. Some generators avoided generating above the thresholds that would have triggered additional spinning reserve liabilities.

  - A revision to the market rules, that changes the cost allocation of spinning reserve commenced on 1 September 2019.[15] This provides a progressive increase in the allocation of spinning reserve liabilities as a generator's output increases rather than allocating the liability in blocks.[16] This has changed generators' bidding behaviour with some generators now bidding higher quantities into the market with the more gradual exposure to spinning reserve liabilities.

- Different load following ancillary service (LFAS) requirements over a 24-hour period:
  - Prior to 2019/20, AEMO identified that it needed 72 MW of LFAS to maintain the balance of supply and demand in real time. This assumption has been included in past modelling of spinning reserve and load rejection reserve proposals.
  - In June 2019, AEMO proposed changes that increased the LFAS requirement to 85 MW between 5:30 AM and 7:30 PM and decreased it to 50 MW at all other times. This was to respond to the increased volatility in supply and demand resulting from higher levels of intermittent generation connected to the network.[17]
  - In anticipation of needing more LFAS, AEMO has included a higher LFAS requirement of 116 MW in the daytime and 70 MW overnight in the modelling for its 2020/21 proposal.
  - Some generators, such as Synergy's gas turbines (excluding Cockburn), can provide both LFAS and spinning reserve. Therefore, a higher LFAS requirement could mean more generation capable of providing spinning reserve may already be dispatched and operating in the market and able to provide spinning reserve.[18]
- Modelling the spinning reserve required to accommodate a single transmission node contingency from the planned connection of new generators on the North Country 330kV line:
  - During 2020, two wind farms (Yandin and Warradarge) are expected to connect to the same transmission line in the North Country area.[19] The possibility of a network outage on the transmission line coinciding with large outputs from the wind farms at times will create the single largest contingency in the WEM and set the spinning reserve quantity.
  - The modelling increases the spinning reserve requirement to meet the largest contingency, including that set by the North Country transmission line, if there is reserve available to provide the required spinning reserve. If there is insufficient reserve able to cover spinning reserve requirement, the model flags a shortfall. No shortfall events were observed in the modelling results.
  - These assumptions influence the quantity of spinning reserve required for 2020/21.
- Generator Interim Access (GIA) network constraints:
  - GIA enables the connection of new generators on a constrained basis. In previous ancillary service parameters modelling, no facilities connected under GIA were

[15] RCP, 2019, *RC_2018_06 Commencement Notice*, (online)

[16] RCP, 2019, *RC_2018_06 Final Rule Change Report*, (online), P. 5

[17] AEMO, 2019, *Ancillary Services Report for the WEM*, (online), P. 16

[18] This assumes that for a plant providing spinning reserve and LFAS, the MW have not been consumed already to provide the LFAS_UP service.

[19] With respect to the transmission system, North Country generally refers to the area from Neerabup terminal (north of Perth), up to Geraldton.

operational. However, new facilities have been connected (or are expected to be connected) within the period modelled.

- AEMO requested guidance from Western Power on the expected level of curtailment for future GIA facilities. AEMO advised Western Power had stated that it could not provide such an assessment, in part because the constraint equations for those facilities have not yet been developed.
- Recent market data from AEMO shows that the level of curtailment experienced by existing GIA connected facilities is not significant under 'system normal' conditions.[20]
- As a result, a reduced capacity factor has not been applied to the GIA facilities and so this did not affect the modelling.

2.2.2 Modelling improvements

AEMO has made two main improvements to the modelling of spinning reserve and load rejection reserve costs, as outlined below:

- Concurrent cost minimisation for spinning reserve and load rejection reserve:
  - Last year, the modelling optimised the dispatch of spinning reserve and load rejection reserve separately in different modelling runs. The first modelling run optimised for spinning reserve. A second modelling run was conducted to generate a balancing merit order for those intervals from the first modelling run where insufficient load rejection reserve had been scheduled. This approach could have resulted in rescheduling in the second modelling run, that failed to provide adequate spinning reserve.
  - This year's modelling identifies the least cost dispatch of generators to provide both spinning reserve and load rejection reserve. This modelling approach is more consistent with the WEM objectives.
- Modelling the ready reserve:
  - The market rules require Synergy to provide ready reserve, meaning that Synergy must reserve enough generation to replace 30 per cent of the largest output of any generator and that generation must be available in 15 minutes.[21] In the event of a generator failure, spinning reserve alone may not be adequate to return the system frequency to normal limits. AEMO may dispatch ready reserve generation to meet the shortfall.
  - AEMO did not include this reservation in previous modelling but has now included ready reserve in the modelling for spinning reserve and load rejection reserve for 2020/21. Withholding generation for ready reserve limits the generation choices available to the model to dispatch and consequently could affect scheduling decisions.

[20] The margin values review is modelled under system normal conditions – with no transmission lines out of service. AEMO advises that GIA generators may be affected due to planned and unplanned network outages, however that has not been considered in the review.

[21] RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 3.18.11A (online)

Details of the changes to the modelling are in EY's method and assumptions report and ancillary services parameter review 2019 final report (public version).[22, 23] AEMO conducted a consultation process on these changes as described in the method and assumptions report.

The extent of the modelling changes outlined above limits the ERA's ability to directly compare the proposed values for 2020/21 against previous years.

[22] Ernst and Young, 2019, *Ancillary Services Parameter Review 2019 Methodology and Assumptions Report, Public Version*, (online)

[23] Ernst and Young, 2019, *Ancillary services parameter review 2019 final report (public version)*, (online)

3. Ancillary services

3.1 Spinning reserve

Spinning reserve refers to generation capacity and interruptible load used to maintain power system frequency within the system's tolerance range in the event of 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.[24]

The market rules provide for three classes of spinning reserve that operate over different timeframes.[25] AEMO is 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 selected suburbs to reduce demand until the supply and demand are brought back into balance.[26] If this does not occur in time, generator protection settings may cause generators to systematically disconnect, which could lead to a system blackout.[27]

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 (in simplified form):

Formula 1

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

where a_t is availability cost 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.

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

The availability payments should compensate Synergy for providing spinning reserve. Modelling is used to identify the availability cost, and to estimate the margins through which the availability cost is to be recovered. AEMO's proposal must reflect:

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

24 RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 3.9.2 (online)

25 Ibid. clause 3.9.3

26 This is also called under-frequency load shedding.

27 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. Technical Rule 3.3.3.3 (b) In Western Power, (2016) *Technical Rules for the South West Interconnected System*, Revision 3, (online), P. 44

The market rules require enough spinning reserve to be able to cover the loss of 70 per cent of either the largest output of any generator or the largest contingency on the network at the time, or the expected maximum increase in demand over a period of 15 minutes, whichever is the greatest.[28]

3.1.1 AEMO's proposed margin values

The ERA determines the margin peak and margin off-peak values.[29] Table 1 summarises AEMO's proposed margin values for 2020/21.

The modelled total spinning reserve cost (the availability cost) is around 28 per cent lower than it was in 2019/20. However, margin values have almost doubled compared to the values in 2019/20. Three main factors could be driving the increase in margin values and decrease in forecast spinning reserve total costs. These factors are changes in the:

- Electricity market, including demand, generation mix and fuel price.
- Modelling of the scheduling of generators in the WEM, as explained in section 3.1.2.
- Market modelling in response to actual and anticipated market rule changes and new connections, as explained in section 2.2.1.

Table 1 Spinning reserve margin values and main variables used in their calculation, proposed for 2020/21 financial year compared to those approved for 2019/20 financial year

Margin value parameters	2019/20 approved*	2020/21 proposed
Margin peak (%)	17.32	39.65
Margin off-peak (%)	12.92	23.24
Underlying values		
Average annual peak spinning reserve requirement (MW)	235.4	251.7
Average annual off-peak spinning reserve requirement (MW)	236.4	240.2
System average marginal peak price ($/MWh)	56.48	35.15
System average marginal off-peak price ($/MWh)	46.08	31.16
Estimated Synergy's peak availability cost ($m)	6.91	5.06
Estimated Synergy's off-peak availability cost ($m)	3.43	2.42
Estimated Synergy's total availability cost ($m)	10.34	7.48

Source: Previous ancillary services parameter review, the ERA's 2019 issues paper and determination, and AEMO's proposal for 2020/21

*Note: *The ERA only determines the margin values for peak and off-peak periods.*

[28] RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 3.10.2(a) (online) and Technical Rules 2.2.1 (d)

[29] AEMO uses the modelled spinning reserve quantity in its settlement calculations but this is not determined or approved by the ERA. Refer to market rule 3.13.3A

3.1.2 Modelling results

Many of the market-driven changes to the modelling outlined in section 2.2 came into effect during 2019/20 and some are scheduled to commence in 2020/21. It is unclear how these market-driven changes will affect the market dynamics. The model used the best available information at the time.

The margin value – expressed as a percentage – is derived by multiplying the forecast balancing price and the amount of spinning reserve required from Synergy. Although AEMO has forecast the total cost of compensating Synergy for that spinning reserve to reduce, the forecast balancing price is forecast to reduce even further, resulting in an increase to the margin values.

The forecast amount of spinning reserve has increased. This larger reserve quantity is driven by three factors:

- Two new wind farms (Yandin and Warradarge) connected to the same transmission line form a single contingency (discussed in section 2.2.1).
- Not counting used LFAS quantities against the spinning reserve requirement.
- Not counting LFAS that is unable to provide a spinning reserve response.
- Changes to the allocation of spinning reserve liabilities (discussed in section 2.2.1).

The modelling assumed Yandin and Warradarge wind farms were only constrained when there was inadequate spinning reserve from other sources to cover the contingency set by those wind farms. The modelling showed the combined output of these two wind farms comprised the largest contingency for around 21 per cent of the time, comparable to Collie in setting the spinning reserve requirement.[30] Sensitivity analyses indicated the output from these and other new renewable generators exerted downward pressure on balancing market prices.[31] Constraining the output from the wind farms increased the balancing price and also the availability cost during peak periods.

The fuel price assumption for Synergy generators ($3.50/GJ) resulted in relatively low balancing prices. AEMO tested the sensitivity of the availability cost to changes in the assumed Synergy gas price. The peak period availability cost was relatively insensitive to fuel price assumptions, but the peak margin values were moderately sensitive to scenarios that resulted in higher balancing prices.

For example, doubling the gas price from $3.50 to $7 per GJ reduced the peak margin value from 39.7 per cent to 20.6 per cent even though the peak availability cost barely changed, from $5 million to $4.9 million.[32]

The off-peak margin values were less sensitive to the assumptions altering the availability cost. While the higher fuel prices tested in the sensitivity analysis increased off-peak availability cost, it also increased the balancing price. The net effect was that the margin value off-peak was relatively insensitive to balancing price. For example, in the base case an off-peak margin value of around 23 per cent was needed to recover the availability cost of $2.4 million from an average balancing market price of $31 per MWh. Doubling the input gas price from $3.50 to $7 per GJ increased the off-peak availability cost to $3.8 million, but the increase in off-peak balancing price from $31 to $41 per MWh means the off-peak margin value only

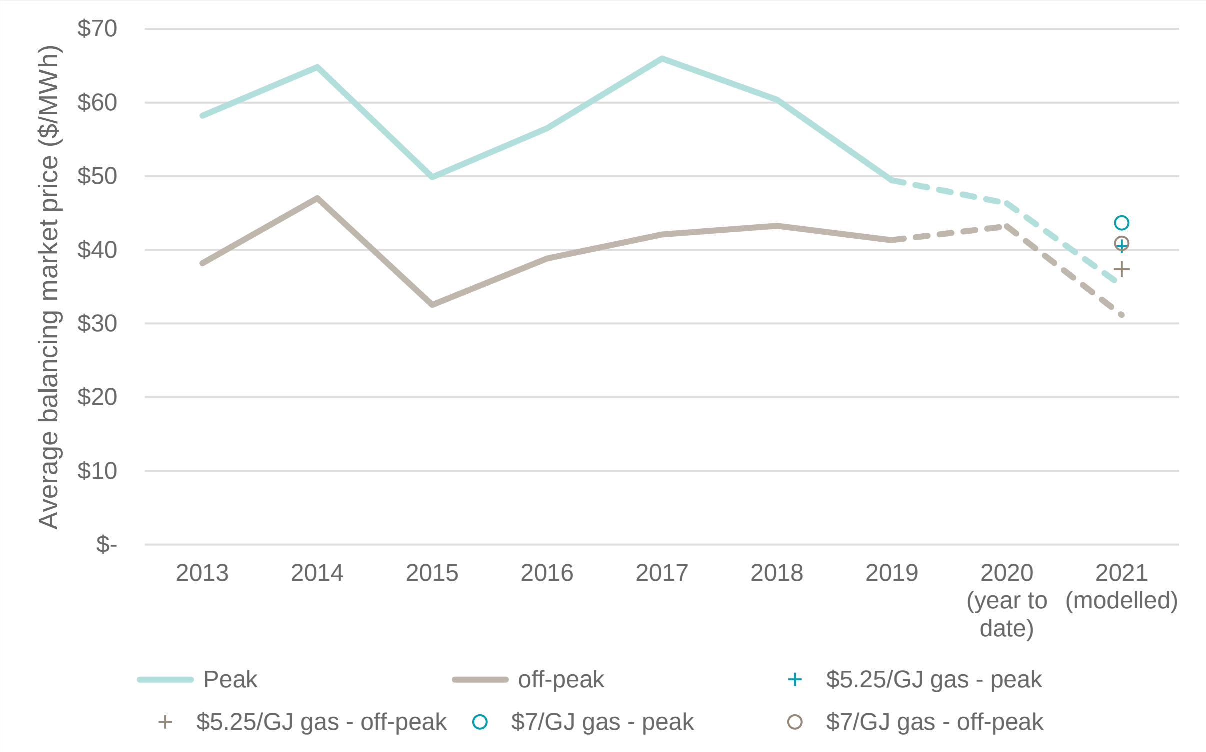
30 Ernst and Young, 2019, *Ancillary Services Parameter Review 2019, Final report – Public Version*, (online), P. 62

31 Ibid. P. 56

32 Ibid. P. 56

fell to 20 per cent. Real and modelled average balancing prices with fuel price sensitivities are shown in Figure 1 below.

Figure 1: Average peak and off-peak balancing market prices – real versus modelled



The modelled balancing prices for both peak and off-peak are lower than annual average values experienced in the balancing market since its start in July 2012. Although the peak value appears consistent with the reductions occurring since 2016/17, 2019/20 is not yet complete and summer is not included in the sample. Following three mild summers, a return to more typical weather would result in higher demand and likely higher prices.[33]

All things being equal, if the modelled balancing prices are too low, the margin values will tend to over-compensate Synergy. If the balancing prices are too high, the margin values would tend to under-compensate Synergy.

Synergy is obligated to offer forward hedging contracts, called standard products. These can provide an alternative view on forward price expectations in the Wholesale Electricity Market.[34] Synergy offers two products, a peak product and a flat product. The flat product is an amalgam of peak and off-peak prices, but the peak prices are directly comparable. Synergy's peak buy product price for 2020/21 is $45.90, which is above the average peak price of $43.63 from the sensitivity analysis that assumed Synergy used gas at $7.00 per GJ delivered.[35] Consequently, Synergy's forward view on balancing market prices is substantially higher than that forecast in AEMO's modelling.

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33 ERA, 2019, *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2019* – Issues Paper, (online), P. 4

34 Synergy is required to offer hedging products termed standard products under its regulatory framework. They obligate Synergy to offer to buy or sell electricity to or from market participants within a regulated price range around Synergy's forecast of the balancing market price.

35 Synergy wholesale standard product webpage, online, accessed 5 December 2019

3.2 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 only happen a few times each year.

AEMO sets the load rejection reserve requirement. The market rules require the standard to be adequate to keep frequency below 51 hertz for all credible load rejection events. The standard may be relaxed by up to 25 per cent where AEMO considers the probability of transmission faults to be low. The nominal requirement is currently a maximum of 120 MW of load rejection reserve, which AEMO can relax down to 90 MW.

AEMO is conducting a trial which aims to reduce the quantity of required load rejection reserve. AEMO has reviewed what is needed to manage frequency and is accounting for other factors, such as load relief, that reduce the amount of load rejection reserve required for system security.[36] In practice, the required quantity varies with the size of the largest load rejection contingency and with available load relief. This trial is reducing the pre-dispatch planned quantity to around 90 MW rather than the maximum 120 MW. Real-time dispatch could reduce this further. It is a positive initiative to help reduce the cost of this ancillary service to Synergy and the market.

Some generators, including wind farms, already have their protection settings set to reduce output when the frequency rises above a threshold such as 51 Hertz, as set in their network access contracts. These generators will automatically reduce output or trip when the system frequency reaches the threshold, requiring no operator intervention.

3.2.1 Proposed load rejection reserve value for 2020/21

Table 2 contains AEMO’s previously proposed load rejection reserve parameter values and the ERA’s previously approved values for 2019/20 to 2021/22. The table also shows the load rejection reserve performance and standard.

36 Some loads, such as motors, increase their 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 their output and the size of the reserve. This varies with system demand and can be around 30 MW for a frequency increase to 51 hertz.

Table 2. Proposed load rejection reserve values (L parameter of Cost_LR)

Year	Requirement	Actual performance (% time at standard)[37] <90 MW	<120 MW	>120 MW	Previously proposed value ($'000)	Previously approved value ($'000)
2016/17	120 MW but may be relaxed by up to 25 per cent (to 90 MW) when the risk is considered low.	3.5	14	86		$1,400
2017/18		6.5	21.5	78.5		$1,400
2018/19	Up to 120 MW. AEMO is also conducting a trial to manage the load rejection reserve quantities.		N/A			$1,400
2019/20		4.5	24.3	75.7	$4,738.2	$1,400
2020/21			N/A		$4,343.5	$1,400
2021/22					$1,086.6	$1,400

Source: AEMO's proposal, past AEMO ancillary service reports, and past ERA determination papers

AEMO has now proposed a new value for load rejection reserve for 2020/21 of $721,000. This is a substantially lower number than proposed in the previous determination for the same period ($4,343,500) and is discussed in the following section.

3.2.2 Modelling results

In last year's determination, the ERA did not accept AEMO's load rejection reserve proposal as the modelled outputs did not appear to reconcile with AEMO's reported scheduling practice.[38] While many factors affect the load rejection reserve requirement when planning generator dispatch and in real-time operation, the decision-making process should be transparent, comprehensible, and capable of being modelled. The ERA Secretariat and AEMO have had extensive discussions since that determination to better understand AEMO's practices and how these compare with the modelling.

Around one quarter of the time, the load rejection reserve falls below the nominal 120 MW requirement, occurring more often during periods of low load. Last year's model always rescheduled Synergy's generators if the spinning reserve optimisation did not schedule at least 120 MW of load rejection reserve during off-peak periods.[39] In practice, such rescheduling does not always occur. [40]

How AEMO schedules and reschedules plants is pivotal to the actual cost of providing load rejection reserve. Understanding when generators are scheduled out-of-merit, meaning higher cost generators displace lower cost generators, is necessary to develop the model.

[37] The load rejection reserve performance statistics relates to the period from May to April reported in AEMO's, 2018 Ancillary Services Report, 2018, online, P. 11

[38] ERA, 2019, *Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22)* – Determination, (online), P. 2

[39] Ernst and Young, 2019, *Ancillary Services Parameter Review 2019, Final report – Public Version*, (online), P. 63

[40] AEMO, 2018, *Ancillary Services Report for the WEM 2018-19*, (online), P. 11

AEMO's modelling scheduled generators out-of-merit if the load rejection reserve requirement could not be met by in merit generators, and decommitted units when they were no longer needed if it was economic to do so. The reserve requirement will vary between the planning horizon (when Synergy's generators are scheduled) and real-time operation. Also, in real-time rescheduling, decisions are also influenced by two wind farms whose output automatically reduces if the system frequency is high. This provides an additional operational buffer that enables the practical real-time requirement to be reduced.

The latest modelling better accounts for the actual scheduling practice used in AEMO's trial. The modelled load rejection reserve requirement, although set at a higher level to be more conservative than practice, more closely reflects the observed levels of load rejection reserve reported in AEMO's annual ancillary services report.[41]

Synergy has stated previously that it was only partially compensated for the costs of providing ancillary services. It also stated that its units were regularly scheduled out of merit to provide ancillary services and the modelling inadequately identified the frequency and magnitude of its costs.[42]

The ERA is interested in receiving stakeholder feedback on the proposed load rejection reserve.

Question

4. Do stakeholders consider the modelling approach to identify the load rejection reserve cost is reasonable? If not, please explain why.

3.2.3 Future opportunities to reduce the cost of load rejection reserve

Frequently, in-merit generation dispatch already provides enough load rejection reserve so that no re-dispatch is necessary. Low demand periods are often when Synergy's generators are more likely to be dispatched out of merit to ensure enough load rejection reserve.

Wind and solar farms can reduce their output rapidly without incurring significant costs, although they would forego energy sales during such occurrences. There are wind and solar farms that may be able to provide automatic load rejection reserve at lower cost than scheduled generators, if their protection systems were re-programmed to do so. This could further reduce the quantity of load rejection reserve that Synergy needs to provide from its scheduled generators out-of-merit.

When renewable generation output coincides with low system demand, there is a higher likelihood that Synergy's coal fired generators that are normally assigned to provide load rejection reserve will have their output reduced. This would constrain their ability to provide load rejection reserve. In these circumstances, the wind and solar farms could provide complementary automatic load rejection reserve capacity, and possibly avoid the necessity to re-dispatch Synergy's generators out of merit at a higher cost to the market.

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41 AEMO, 2019, *Ancillary Services Report for the WEM 2019*, (online), P. 11-12

42 Everett A., 2019, *Ancillary Services Parameters –submission , Synergy*, (online), P. 4

Market rule 3.9.6 states that:

> Load Rejection Reserve Service is the service of holding capacity associated with a Scheduled Generator in reserve so that the Scheduled Generator can reduce output rapidly in response to a sudden decrease in SWIS load.

The market rule defining load rejection reserve only refers to a scheduled generator providing the service. This rule would need to change to allow non-scheduled generators to actively, or by default passively, provide load rejection reserve.

Question

5. In what way, if any, are wind and solar farms able to contribute to load rejection reserve? How should their contribution be considered in determining the load rejection reserve value?

3.3 System restart service

Also termed 'black start', the system restart service is provided by generators that can start without grid supply and re-energise part of the transmission network to allow other generators to start. This progressively re-energises the whole grid in the event of a system-wide blackout.

AEMO contracts with generators able to provide system restart services. Restart costs are based on pricing from these contracts.[43]

AEMO has divided the SWIS into three sub-network areas for system restart purposes:

- North Metropolitan
- South Metropolitan
- South Country.[44]

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.[45] The South Country contract runs until 23 October 2028 and is the dominant component of the total proposed system restart cost (section 3.3.2).

The North Metropolitan and South Metropolitan services contracts expire on 30 June 2021. AEMO has commenced work on procuring new service contracts. This presents an opportunity to seek participation from more service providers in the tendering process. This could include other generators in service areas where black start capable generators already exist or could include generators that may be modified to be able to provide the service.

43 RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, market rule 3.9.8 (online)

44 AEMO, 2018, *2018 Ancillary Services Report*, (online), P. 19

45 Ibid, P. 21

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 their share of electricity consumption.[46]

When entering into an ancillary services contract, AEMO must:

- Seek to minimise the cost of meeting its ancillary service requirements.[47]
- Consider a competitive tender process unless it would not minimise the cost of ancillary services to the market.[48]
- Report the capacity, prices, and terms for calling on the contracted facility to provide the restart capacity, to the ERA.[49]

The ERA reviews AEMO's proposed system restart costs against the market rule requirements, and only determines system restart costs consistent with the rules. However, if there is a gap between the system restart values approved by the ERA and AEMO's contracted costs, the contract costs are still recovered through a Cost_LR shortfall charge.[50] This mechanism ensures that AEMO is not exposed to the risk that the regulator does not approve the contracted sum. However, regulatory oversight and determination of contracted costs should provide discipline to the procurement process. However, neither AEMO nor the contracted parties are bound by the regulator's decision. Therefore the procurement process risks undermining efficient pricing outcomes.

3.3.1 Matters from the previous determination

The ERA did not support AEMO's previous proposal for system restart costs. After examining the documentation and the financial model for the North Metropolitan contract, the ERA found that some of the tendered costs were inconsistent with the cost of providing the system restart service. Rather, the tendered price included adjustments to ensure that the necessary level of revenue for the generator to ensure a commercial return on investment. This return was for the whole asset, rather than just the capital works required for system restart service. The ERA did not consider this to be consistent with the market objectives.

3.3.2 Proposed system restart service value for 2020/21

AEMO's new proposed system restart cost, the R component of the Cost_LR value for 2020/21, is not materially different to its previous proposal. Table 3 summarises AEMO's previously proposed system restart values and the previous system restart costs approved by the ERA.

[46] RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 9.9.1 (online)

[47] Ibid. clause 3.11.9 (a)

[48] Ibid. clause 3.11.9 (b)

[49] Ibid. clause 3.11.10

[50] Ibid. clause 9.9.3B

Table 3: System restart service costs (R parameter of Cost_LR)

Financial year	IMO*/AEMO proposed ($'000)	ERA approved ($'000)
2013/14	$508	$508
2014/15	$521	$521
2015/16	$534	$534
2016/17	$929	$547.9
2017/18	$3,273	$561.7
2018/19	$3,355	$575.7
2019/20	$3,316	$2,924
2020/21	$3,293	$2,899
2021/22	$3,375	$2,961

* IMO was the former Independent Market Operator

Source: Past AEMO and Independent Market Operator system restart value proposals

AEMO has proposed a new system restart service value of $3,277,661 for 2020/21 compared to $3,293,000 previously proposed for the same period. The new proposed value reflects the total contracted cost of the three existing system restart contracts, escalated in accordance with the contracts by the Consumer Price Index. The small variance between their new proposed value and previous proposed value (for 2020/21) is still to be reviewed but it is expected to be due to application of a more recent CPI forecast to the existing contracts.

AEMO advised:

> As two of the Ancillary Service Contracts for System Restart Facilities expire in June 2021 and are practically unable to be renegotiated for the 2020/21 Financial Year, AEMO has proposed the R component of the Cost_LR value for the 2020/21 Financial Year based on these contracts.

AEMO indicated that it planned to resubmit proposed costs for system restart services for 2021/22 to the ERA by 30 November 2020. These costs will be based on new system restart contract costs for the North and South Metropolitan areas.

3.3.3 Challenges to system restart procurement

The WEM is a highly concentrated market and that is dominated by Synergy.[51] The concentration is increased further by dividing the network into sub-regions for system restart services, which reduces the pool of possible system restart suppliers. However, the zoning of system restart services is necessary. Where a natural disaster, such as bushfire, earthquake, or cyclone damages infrastructure it can isolate a network region or disable system restart facilities in a region. Multiple services, in other regions, may be necessary to restore electricity

[51] ERA, 2019, *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2019 – Issues Paper*, (online), P. 7-8

supply if one provider is on outage, or maintain service in isolated areas where repairs may take some time.[52]

Under the market rules, AEMO must consider a competitive tender process to procure the system restart service,[53] unless this approach would not meet its obligation to minimise the cost of providing the ancillary service.[54] However, the market rules provide no clear alternative should a tender process be unlikely to yield economically efficient prices. This places AEMO in a difficult position.

It is in everyone's interest to ensure the system restarts in the event of a system black-out, but generators provide the restart service. However, generators are also aware that AEMO's black start obligation is insensitive to the cost approved by the ERA because of the shortfall charge mechanism. Although the ERA may approve a lower system restart cost than AEMO proposes, the shortfall change ensures the generator receives the higher proposed cost, consistent with the system restart contract. This increases the cost to insure against very infrequent system blackouts.

System restart services have similar characteristics to other regulated utility services: a limited competitive pool, a severe consequence of failure, and limited product substitutes. The tendering process could be structured differently to reduce the risk that the cost includes compensation for unrelated factors, and to improve the transparency of the process. The process could be improved by:

1. Improving the pool of potential suppliers.

2. Reducing the ability for tenderers to cover unrelated risks, equipment or services.

The pool of system restart providers could be improved by exploring the suitability of other generators, that may be able to re-energise the network, but that are outside the current system restart zones. The tender documentation could be drafted to specify the service required and acceptable performance criteria, instead of listing a specified technical approach to achieve re-energisation.

Removing unrelated costs from system restart contracts could be achieved through more open disclosure requirements. Tender documents might include standardised schedules to itemise the capital works and other cost items and require submission of the underlying financial model. This would provide for a reasonable (commercial) return on the assets necessary to provide a black start service but limit the ability to earn a return on unrelated assets or costs, market risks or other unrelated factors.

AEMO is examining the best approach for procuring system restart services from July 2021 onwards for network areas other than South Country area and will continue to engage with the ERA Secretariat through the process.

52 Western Power, 2014, *System Restart Services (System Restart Standard)*, Western Power, Perth, (online), p. 11-12

53 RCP, 2019, *Wholesale Electricity Market Rules (1 November 2019)*, clause 3.11.4 (online)

54 Ibid. clause 3.11.9

Questions

6. What barriers can you see to providing system restart services and how could AEMO structure its procurement process to deliver more competitive/lower cost outcomes?
7. Could the system restart service be provided from other areas of the network to encourage participation from more service providers or other existing facilities, for example in North Country, East Country, Eastern Goldfields or other areas?

Appendix 1 List of Tables

Appendix 2 List of Figures