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

Determination

31 March 2021

Economic Regulation Authority
WESTERN AUSTRALIA

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Executive summary

The Australian Energy Market Operator uses ancillary services to maintain the security of the South West Interconnected System. Spinning reserve and load rejection reserve are complementary but opposite ancillary services. Spinning reserve provides a rapid increase in generation to compensate for the sudden loss of a large generator. 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.[1]

Synergy is the default provider of ancillary services in the Wholesale Electricity Market and Synergy's costs to provide these ancillary services are recovered through administered mechanisms in the market rules. The Economic Regulation Authority determines the three parameter values for these mechanisms.

The market rules require AEMO to propose spinning reserve, load rejection reserve and system restart parameters to the ERA for approval each year. The ERA must consult on the proposed parameters and consider AEMO's proposal, the market objectives and any stakeholder feedback received to make its determination.[2] The ERA must determine the parameters to apply in 2021/22 by 31 March 2021.

In May 2020, 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 was undertaking to replace two system restart contracts that expire in mid-2021.

AEMO last modelled system restart and load rejection reserve in 2019. Since then many market characteristics have changed, including:

- continued penetration of rooftop solar and grid-connected wind and solar farms
- increased quantities of spinning reserve and load following ancillary services
- increased instances of negative wholesale prices in the balancing market
- updated information on generation plant, such as operation and maintenance costs
- changes in fuel prices, in particular increasing gas prices.

The ERA reviewed AEMO's proposal and concluded that too many factors had changed for the ERA to base its determination on modelling that was now out-of-date. Consequently, the ERA conducted its own modelling and investigation of spinning reserve and load rejection reserve requirements and costs over 2021/22. Market dynamics, in particular an abundance of renewable generation, are driving changes in the ancillary services quantities and forecast costs.

Market dynamics

In the last 10 years nearly 1,000 MW of renewable generation, mostly wind farms, has connected to the South West Interconnected System. By January 2021, households had installed approximately 1,600 MW of solar systems on their rooftops.[3] This combined quantity of generation, 2,600 MW, is greater than the capacity of Synergy's entire gas and coal fleet.

[1] The cost to provide the fourth ancillary service, the Load Following Ancillary Service (LFAS), which AEMO uses to balance supply and demand in real time, is determined through a market.

[2] Wholesale Electricity Market Rules, 1 February 2021, rule 1.2.1, (online).

[3] Clean Energy Regulator, 2021, *Postcode data for small-scale installations*, (online).

The supply of low-cost renewable electricity in the market and lower demand for electricity from the network during the middle of the day is reducing average balancing prices when compared to previous years. Lower wholesale electricity prices are eventually passed through to consumers. However, the weather-dependent and variable output from renewable generators is increasing the quantity and cost of the ancillary services needed to maintain power system security. The forecast cost of spinning reserve and load rejection reserve has increased 45 per cent from $9.6 million in 2020/21 to $13.9 million in 2021/22. If the higher ancillary service cost is passed on through retail tariffs this costs each household around $4 in total each year.

Electricity generation from rooftop solar reduces demand for electricity from the network in the middle of the day and large coal generators, such as Collie or Muja, lower their output in response. Historically, large coal and gas generators have provided ancillary services. The large coal generators are limited in how much further they can lower their output and still provide the load rejection reserve service. AEMO needs to schedule higher-cost gas-fired generators to maintain the load rejection reserve requirement. Using more gas drives up the cost of load rejection reserve. The problem continues overnight, as output from wind farms takes over from solar, continuing to put downward pressure on the output from coal-fired generators. Again, AEMO needs to schedule more expensive gas-fired generation to maintain system security. The need to schedule gas generation both during the day and overnight to provide the load rejection reserve service contributes to the increase in load rejection reserve costs from $1.2 million in 2020/21 to a forecast of $7.3 million in 2021/22.

The quantity of ancillary services needed to maintain system security is also increasing and contributing to higher ancillary service costs. AEMO has advised the WEM that network faults on the 330kV transmission line north of Perth can change the power quality in the network and cause some of the rooftop solar fleet to disconnect. AEMO has increased the spinning reserve quantity by between 70 MW and 130 MW for some intervals, approximately 30 per cent to 50 per cent higher than current levels. This will ensure there is generation available to increase output and meet demand when generation on the 33kV line and the output from a proportion of rooftop solar systems is lost.

The additional spinning reserve contingency caused by rooftop solar disconnecting increases the overall requirement for spinning reserve at the time the market is least flexible - in the middle of the day when rooftop solar generation output is at its highest, demand for electricity from the network is lowest, and balancing market prices are at a minimum. Large coal generators will be operating at low levels of output and are unable to quickly increase output to provide spinning reserve. AEMO again schedules more costly gas generators to cover the higher spinning reserve contingency.

When renewable generation is generating at a maximum during the middle of the day and between midnight and dawn, balancing prices are low and sometimes negative. Ancillary service payments must compensate generators for the difference between the balancing price and their cost to provide the service. When more costly generators are needed to maintain system security and the balancing price is low, ancillary service payments are needed to increase to cover those generators' costs.

Margin values

The ERA must determine 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, known as the margin values. The administered mechanism assumes a positive relationship between balancing market prices and spinning reserve costs. Historically, as the balancing price has increased, so has the return on energy sales Synergy forgoes to provide spinning reserve and the higher the spinning reserve payment needed to compensate Synergy.

Market dynamics have reversed the relationship between balancing price and the cost to provide spinning reserve. The high penetration of low-cost renewable generation in the market is lowering balancing prices overall and increasing the incidence of negative balancing price intervals, from 500 in 2019/20 to 1,100 by the end of February 2021, and 3,700 negative intervals are forecast for 2021/22. As balancing prices decrease in 2020/21, spinning reserve costs rise because more costly gas-fired generation is providing the service. When balancing prices rise, spinning reserve costs decrease because the service is more likely to be provided by lower cost coal generation.

The margin value mechanism for paying Synergy for spinning reserve relies on a positive relationship between the balancing market price and the cost of spinning reserve. When balancing prices are negative, Synergy will not be compensated for providing spinning reserve, indicating that there are problems with using margin values as a compensation mechanism.

Although there are problems with the mechanism, the ERA is required to determine margin values to compensate Synergy for providing spinning reserve. To do this, the ERA has assumed that the full amount of forecast compensation over 2021/22, $6.5 million, will be paid to Synergy when balancing prices are positive. The ERA has determined margin value percentages of 12.6 per cent in peak periods and 23.4 per cent in off-peak periods.

There are risks with using a forecast to determine ancillary service parameters in a rapidly changing market. The ERA forecasts that over 2021/22 balancing prices will be negative approximately 20 per cent of the time, and when prices are negative the costs to supply spinning reserve are high. For the rest of the year, the ERA forecasts spinning reserve costs will be low or close to zero. If the number of negatively priced intervals is different to the ERA's forecast, then Synergy's actual compensation may vary. For example, if the actual number of negatively priced trading intervals in 2021/22 is higher than forecast or the average negative balancing price is lower, the determined margin values may undercompensate Synergy for providing spinning reserve. If there are fewer negatively priced trading intervals or average balancing prices are higher than forecast, Synergy is likely to be overcompensated for providing spinning reserve and other generators bear this cost.

Although the administered margin value mechanism is no longer working as anticipated, this is the last year that the mechanism will be used. From October 2022, system security services, renamed essential services, will be provided through a competitive process. This change is part of the State Government's energy reform program.

Cost_LR

The ERA must determine the parameter Cost_LR to apply in 2021/22. 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.

The ERA has forecast the load rejection reserve cost for 2021/22, acknowledging the effect of market dynamics and based on the most up-to-date market and generator information available. The 'L' element of the Cost_LR parameter for 2021/22 is $7,386,000.

System restart costs are based on the contracted costs of providing the service. AEMO proposed a new system restart cost of $3,369,438 for 2021/22.

The new cost is based on the tendered costs for the North and South Metropolitan system restart service contracts and the existing South Country contract costs. The ERA has approved AEMO's proposed cost for system restart and has determined that the 'R' element of the Cost_LR parameter for 2021/22 is $3,369,438.

Determination

In accordance with clauses 3.13.3A and 3.13.3B of the market rules, the ERA determines that:

- The values of margin peak and margin-off peak parameters for 2021/22 are 12.6 per cent and 23.2 per cent respectively, with spinning reserve quantities of 240 MW and 241 MW respectively.

- The value of the Cost_LR parameter is $10,755,438 for 2021/22.

1. Introduction

The South West Interconnected System uses ancillary services to maintain the balance of the supply and demand for electricity at all times. This determination covers three ancillary services:

- Spinning reserve provides a rapid increase in generation following a sudden shortfall in electricity supply after the loss of a large capacity generator or a main transmission line that disconnects generation.
- Load rejection reserve provides a rapid decrease in generation output where a large load is lost, such as when a transmission line trips. This service, and spinning reserve, are required to maintain system frequency within acceptable limits.
- The system restart service provides the capability of starting up in total system blackout conditions and can energise the power system to enable other generators to be started up.

The Wholesale Electricity Market Rules require AEMO to undertake a review of the costs of these ancillary services and each year propose peak and off-peak margin values percentages that are used to calculate spinning reserve costs, and every three years forecast costs for providing load rejection reserve and system restart services, together called Cost_LR.[4]

On 30 June 2020, AEMO submitted proposed spinning reserve and load rejection reserve parameters for 2021/22 to the ERA for approval. 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.[5] For spinning reserve settlement parameters and load rejection reserve, AEMO proposed rolling over the ERA's determined values for 2020/21.

On 30 November 2020, AEMO submitted revised system restart costs.[6] 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.

The ERA undertook modelling to estimate likely spinning reserve and load rejection reserve costs and quantities for 2021/22, finding that market dynamics are quickly and significantly changing ancillary service quantities and costs in the market.

The ERA published an issues paper on 9 February 2021 and a subsequent addendum to the issues paper on 12 March 2021 and invited stakeholders to comment. This addendum summarised amended modelling that was foreshadowed in the issues paper where data and information were not available at the time of publishing. The ERA received five submissions in response to both papers.

This paper determines the costs of the three ancillary services – spinning reserve, load rejection reserve and system restart – to apply in 2021/22. The paper is structured as follows:

- The rest of section 1 outlines the ERA's obligations under the market rules.

4 The market rule 3.13.3C enables AEMO to propose Cost_LR parameters more frequently if it believes load rejection and system restart costs will be "materially different" to those determined by the ERA. AEMO has made separate Cost_LR proposals each year since 2019/20.

5 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.

6 AEMO, 2021, *Update to Cost_LR parameters for the 2021/22 financial year*, (online)

- Section 2 explains what the three ancillary services are and how the costs to provide them are recovered from the market.
- Section 3 outlines AEMO's proposal for margin values, load rejection reserve and system restart costs for 2021/22.
- Section 4 highlights changing dynamics in the WEM that have contributed to a shift in the cost of providing ancillary services.
- Section 5 explains the ERA's determination of margin values, the spinning reserve quantity and load rejection costs for 2021/22.
- Section 6 explains the ERA's determination of system restart costs for 2021/22.
- Appendix 1 details the ERA's modelling process.

1.1 Requirements for the ERA's determination

The ERA must make its determination on the values to apply in 2021/22 by 31 March 2021:

> 3.13.3A. For each Financial Year, by 31 March prior to the start of that Financial Year, the Economic Regulation Authority must determine values for the parameters Margin_Peak and Margin_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following:
>
> a) by 30 November prior to the start of the Financial Year, AEMO must submit a proposal for the Financial Year to the Economic Regulation Authority:
>
> i. for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, AEMO must take account of:
>
> 1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Peak Trading Intervals; and
> 2. the loss in efficiency of Synergy's Scheduled Generators that AEMO has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves;
>
> ii. for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, AEMO must take account of:
>
> 1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Off-Peak Trading Intervals; and
> 2. the loss in efficiency of Synergy's Scheduled Generators that AEMO has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and
>
> b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.[7]
>
> 3.13.3B. For each Review Period, by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must determine values for

[7] Wholesale Electricity Market Rules, 1 February 2021, rule 3.13.3A, (online).

Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

a) by 30 November of the year prior to the start of the Review Period, AEMO must submit a proposal for the Cost_LR parameter for the Review Period to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service and Dispatch Support Service except those provided through clause 3.11.8B;

b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.[8]

In October 2022, the WEM is scheduled to adopt a market-based mechanism for ancillary service price setting. The ERA's 2021/22 determination will cease in June 2022, which is 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. The ERA will liaise with Energy Policy WA closer to the commencement of the new market to address this gap and discuss which parameters need to apply from July to October 2022.

8 Ibid, rule 3.13.3B, (online).

2. What are ancillary services?

2.1 Spinning reserve service

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. The market rules allow spinning reserve to be provided by scheduled generators, interruptible loads, or a combination of the two.[9]

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

- 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
- the expected maximum increase in demand over a period of 15 minutes.[10]

The estimated spinning reserve quantities used in the ERA's determination on margin values in 2020/21 were 252 MW in peak periods and 240 MW in off-peak periods.

2.1.1 How the cost of spinning reserve is recovered from the market

Synergy is the default provider of spinning reserve service in the WEM and provides spinning reserve by withholding some generation capacity from the balancing market and making it available for AEMO to use to maintain system security. Synergy foregoes revenue to provide spinning reserve and therefore should be compensated. This cost is referred to as Synergy's availability payment.

The market rules require AEMO to propose a value for spinning reserve that considers:

- 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 only part load prior to being dispatched to provide spinning reserve.[11]

The availability payments 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 using the following equation:

[9] Wholesale Electricity Market Rules, 1 February 2021, rule 3.9.2, (online).

[10] Ibid, rule 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.

[11] Wholesale Electricity Market Rules, 1 February 2021, rule 3.13.3A(a), (online).

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.[12]

The market rules provide for peak and off-peak margin values to recognise the differing availability costs during peak and off-peak intervals.[13]

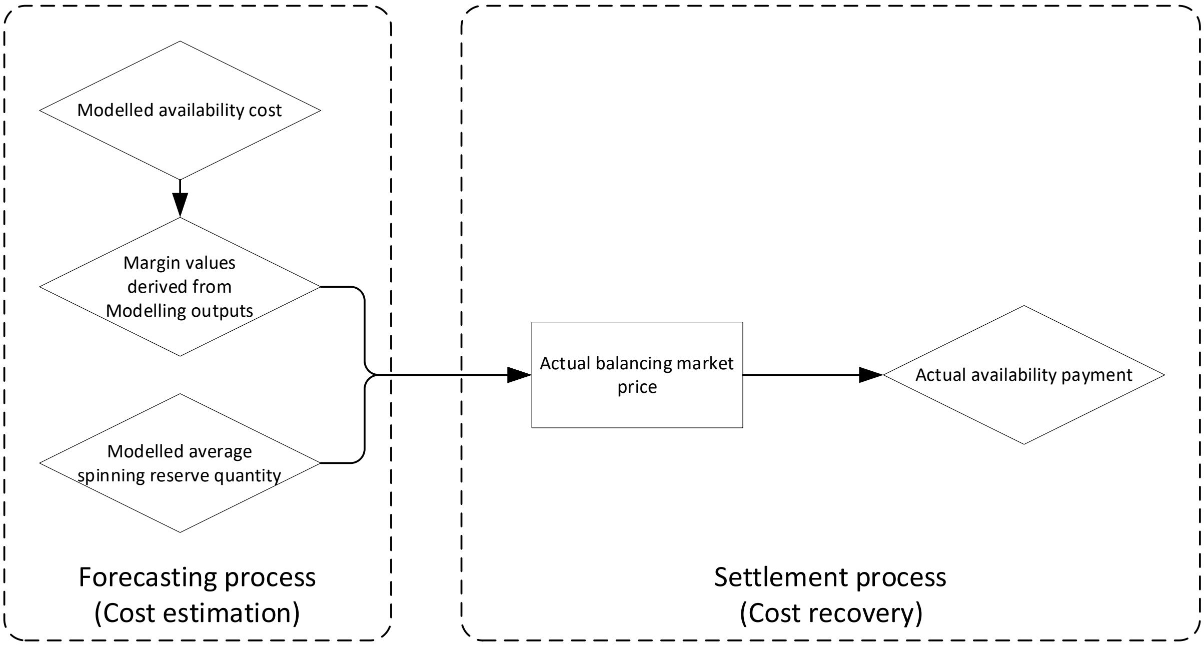
Due to the complexity of an electricity market, modelling is a central element of determining the values used in market settlement. Modelling accounts for changes in fuel cost, other changes to the operating cost of generators, and the number of generators participating in the WEM.

Historically, the ERA has used regression analysis to derive the margin values. This analysis determined the slope of the line required to approximate the forecast availability cost when applied to forecast balancing prices and the average spinning reserve quantity provided by Synergy.

The ERA needed to apply a different method to derive the margin value percentages for 2021/22. The reasons for this and the method used are explained in section 5.4.

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

Figure 1: Application of modelled values to cost recovery



Source: ERA

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

13 Peak trading intervals occur between 8:00 AM and 10:00 PM. Off-peak trading intervals occur between 10:00 PM and 8:00 AM.

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.

2.2 Load rejection reserve service

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 system security. These large load rejection events typically 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, 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.[14]

Synergy is the default provider of load rejection reserve.

2.2.1 How the cost of load rejection reserve (cost_L) is recovered from the market

Synergy is compensated for providing load rejection reserve through the cost_L component of Cost_LR.

The cost of providing load rejection reserve is borne by market participants based on their share of consumption. A technical explanation of the method to calculate cost_L is presented in Appendix 1.

2.3 System restart service

System restart is the ancillary service that pays generators capable of re-energising the electricity system, or parts of the electricity system, following a full blackout. Generators that can start without grid supply will re-energise part of the transmission network, which then allows other generators to start. A diversity of system restart services is needed across the network to ensure that 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 has determined that it needs three service providers in geographically different parts of the network to provide for system recovery. These regions are:

- North Metropolitan
- South Metropolitan

14 AEMO, 2020, *Ancillary Services Report for the WEM 2020*, (online), P. 17.

- South Country.[15]

When entering an ancillary services contract, AEMO must:[16]

- 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.

2.3.1 How the cost of system restart (cost_R) is recovered from the market

The ERA reviews AEMO's proposed system restart costs against the market rule requirements and determines system restart parameters consistent with the market rules. 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.[17]

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.

There is a problem with the application of the shortfall charge if the ERA determines a lower system restart value than the contracted system restart cost from a third-party service provider. This is discussed further in section 6.2.

[15] 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).

[16] Wholesale Electricity Market Rules, 1 February 2021, rules 3.11.9(a), 3.11.9(b), and 3.11.10.

[17] Ibid, rule 9.9.1 (online).

3. AEMO's proposal

The market rules require AEMO to propose the parameters for spinning reserve, load rejection reserve and system restart service to the ERA by 30 November each year.

On 30 June 2020, AEMO submitted its proposal to the ERA for approval. AEMO considered that modelling undertaken by its consultant, Ernst and Young (EY), for its 2020/21 proposal would be suitable for 2021/22 and proposed the same values as 2020/21:

> AEMO submits that the modelling that informed the 2020/21 parameters used robust input assumptions that are equally applicable to the current energy sector environment.
>
> AEMO submits that the 2020/21 inputs are consistent with current market conditions. As a result, AEMO (and Market Participants) can avoid incurring considerable resourcing and financial costs in connection with another end-to-end modelling process.[18]

When proposing the same values as 2020/21, AEMO noted the following points:

- Demand characteristics were substantively the same between 2020/21 and 2021/22.
- Fuel prices had not shifted radically, and gas market prices likely lay between the base case and the sensitivity scenario that the ERA used to inform the determination for 2020/21.
- Load following requirements were 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 using updated information.[19] This is discussed further in section 6.

AEMO proposed the following values.

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

Parameter	Unit	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: The ERA's previous determination and AEMO's proposed values for 2020/21.

The ERA does not agree that the market modelling AEMO's consultant undertook in 2019 is suitable for determining ancillary service parameters in 2021/22. Market changes in the

18 AEMO, 2020, *Margin Values and Cost_LR parameters for the 2021/22 financial year*, (online).

19 AEMO, 2020, *Update to Cost_LR parameters for the 2021/22 financial year*, (online).

intervening two years have made redundant many of the assumptions used in AEMO's original modelling. This is explained further in section 5.2.

On 14 January 2021, AEMO advised the ERA that it had increased the quantity of spinning reserve by an additional 70 MW to 130 MW. AEMO advised that the additional spinning reserve was needed only in some intervals. Following analysis of the power system following the loss of a generator or transmission line, AEMO identified that additional spinning reserve was needed when the 330kV transmission line north of Perth fails and disconnects wind farms (such as Yandin and Warradarge wind farms) and scheduled generators (such as Newgen Neerabup, and Pinjar Power Station). AEMO advised the ERA that network faults on this line created changes to the power quality (either the frequency, the rate of change in frequency, or voltage deviations) that induce some of the rooftop solar fleet to disconnect. The momentary loss of rooftop solar increases demand for electricity from the network. AEMO must have sufficient spinning reserve available so that the generators providing the spinning reserve service can increase their output to meet the additional demand.

In its submission to the ERA's margin values issues paper on 4 March 2021, AEMO noted that it had undertaken further analysis using improved models and actual contingency events.[20] Following this analysis, AEMO considered that the largest contingency, and the spinning reserve required to mitigate that contingency, should also include the consequential disconnection of some of the rooftop solar fleet.

AEMO advised that it would continue to investigate and provide the ERA and market participants with further information in due course.

In late January 2021, the ERA received written communication from AEMO staff. This advised that AEMO expected to increase Load Following Ancillary Service (LFAS) quantities to a range of 106 MW to 120 MW for daytime periods as part of the ancillary service requirements proposed for 2021/22.[21] AEMO said that the increase was linked to variability in the output of rooftop solar and advised that it would conduct additional analysis before finalising its LFAS proposal.

The ERA has included the revised quantity of spinning reserve and expected LFAS increase identified by AEMO as part of its determination. The market dynamics driving changes in ancillary service quantities and costs are explained in section 4.

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[20] AEMO, 2021, *Submission on Issues Paper: Ancillary service costs – Spinning reserve, load rejection reserve and system restart (Margin Values Cost_LR) for 2021/22*, (online).

[21] AEMO did not consider it would need additional LFAS overnight.

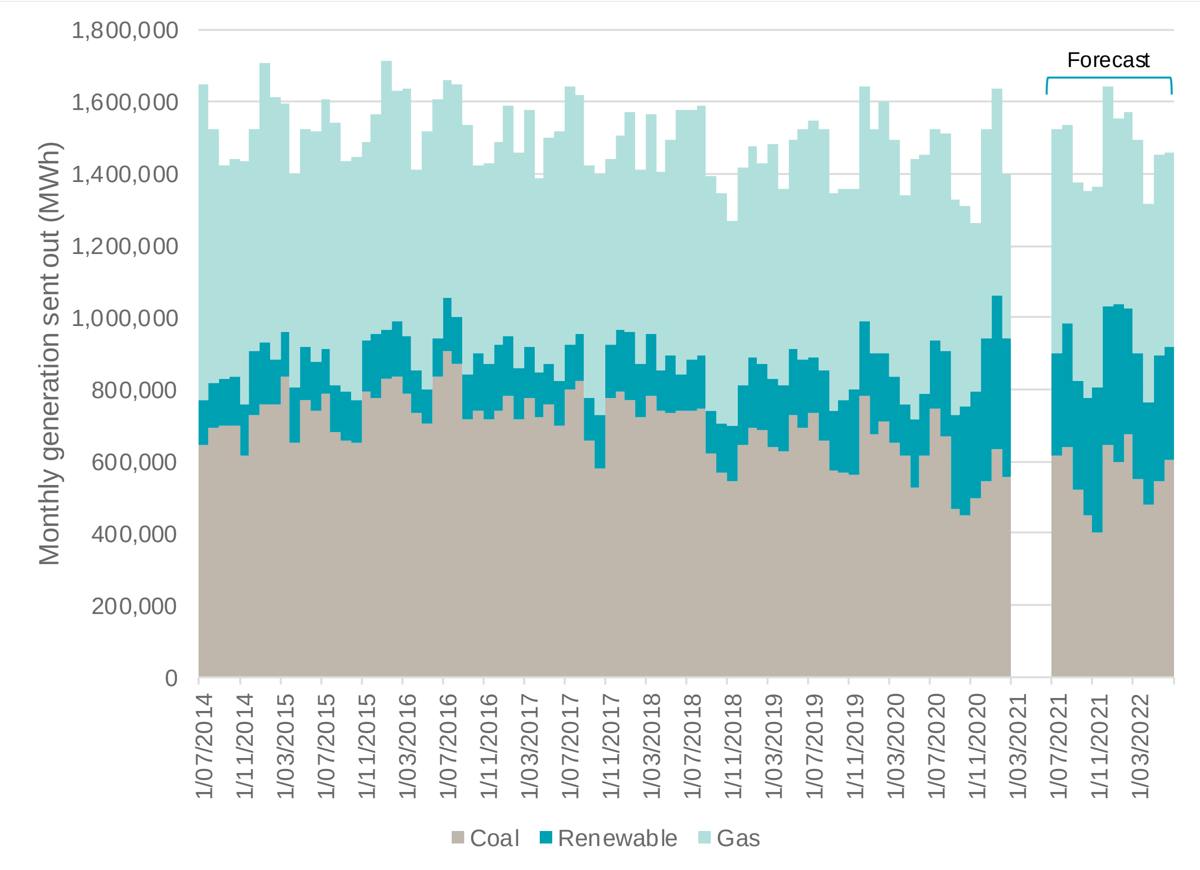
4. Market dynamics

The WEM is undergoing significant change that is affecting the quantity and cost of ancillary services. The changes to electricity supply and demand in the WEM are forecast to continue more rapidly and markedly through 2021/22. In submissions to the issues paper, Bluewaters Power and NewGen Power Kwinana acknowledged the pressure the market dynamics were placing on thermal generators.[22]

Figure 2 below shows historical and forecast generation by fuel type. The chart shows three trends:

1. Reducing total demand for electricity.
2. Reduced output from coal fired power stations.
3. Increased output from renewable generation.

Figure 2: Monthly output of scheduled and non-scheduled (renewable) generators – 2014 to 2022



Source: AEMO data and ERA modelling

22 Bluewaters Power and NewGen Power Kwinana, 2021, *Response to issues paper – ancillary service costs – spinning reserve, load rejection reserve, and system restart (margin values Cost_LR) for 2021/22*, P. 1, (online)

Over 2020, there was a substantial increase in the quantity of renewable generation capacity connected to the market. This was in the form of grid-connected wind and solar projects and small distributed generation systems (predominantly rooftop solar).

Grid-connected renewable projects participating in the WEM have very low marginal operating costs. The variable output of renewable generators places pressure on the larger coal and gas generators that cannot quickly increase or decrease their output to respond and provide ancillary services to maintain system security. The ERA has commented on the output changes to large thermal generators in past reviews of the effectiveness of the wholesale electricity market.[23]

The increasing volume of low-cost generation, coupled with consumers substituting their own rooftop solar generation for electricity from the network, has reduced daytime electricity demand and electricity prices. Balancing prices are commonly below zero during daytime periods, especially over weekends and during the shoulder seasons either side of the summer period when the output of rooftop solar generation is relatively high, but temperature-sensitive loads like refrigeration and air conditioning loads are low.[24]

Thermal generator output follows the trend of lower daytime demand. The output of these generators has historically set the spinning reserve requirement and their lower output serves to reduce one driver for spinning reserve quantity.

Western Power connected several generators to the north country network region that are subject to constraints. AEMO suggested that the physical network structure was such that when unplanned outages occurred on the network, those outages triggered widespread load increases resulting from the disconnection of rooftop solar systems.[25] This increased the contingency that must be covered by spinning reserve at the time when conventional thermal generators such as Collie and Muja were under the greatest pressure to remain in service.

Demand also decreases overnight, which coincides with when wind farm output tends to be highest. Similar to mid-day low demand periods, this reduces the operational room for large thermal generators to reduce output. Prices are depressed and gas generation is again run out-of-merit to provide spinning reserve and load rejection reserve. The net effect of the combined north country contingency and increased wind output overnight is that balancing market prices fall and higher-cost, more flexible gas generation is needed to ensure system security.

Figure 3 below shows average historical and forecast mid-day balancing market prices. The observed price troughs in the middle of the day have become more frequent and deeper. These negative prices pull down the average balancing price. The ERA's modelling also forecasts that the price trough between midnight and sunrise will deepen as a consequence of higher wind output overnight and lower daytime demand from rooftop solar generation.

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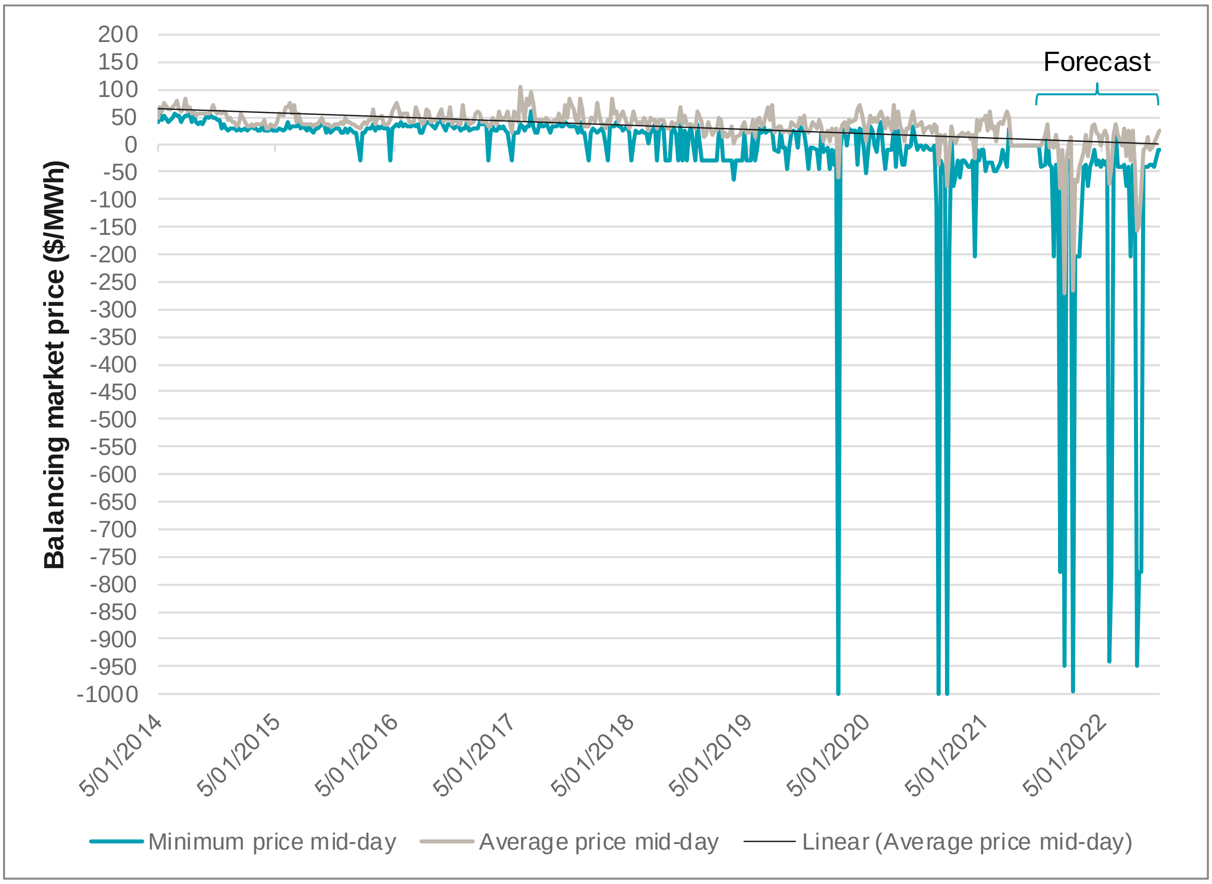
23 ERA, 2020, *Report on the effectiveness of the Wholesale Electricity Market*, p. 7, (online). T

24 Shoulder periods are typically autumn and spring months.

25 AEMO, 2021, *Submission on Issues Paper: Ancillary service costs – Spinning reserve, load rejection reserve and system restart (Margin Values Cost_LR) for 2021/22*, pp 1-3, (online).

Figure 3: Historical and forecast mid-day average and minimum balancing market prices – 2014 to 2022



Source: AEMO data and ERA modelling

Negative prices mean that generators scheduled out-of-merit have a large difference between their operating costs and the market price that should be met by ancillary service payments. However, the market rules ensure Synergy would not normally be recompensed for spinning reserve when balancing prices are negative. This is explored further in the following section.

4.1 Out-of-merit costs

For most generators, to operate out-of-merit they must be 'constrained on' to be dispatched within the rules.[26] However, Synergy bids as a portfolio and its individual offer tranches are not tied to particular generators. This has implications for Synergy and its operating costs.

There are circumstances where AEMO may need to alter the dispatch of spinning reserve or load rejection reserve above what was anticipated when Synergy prepared its offers and when AEMO prepared its dispatch schedule for the day. For example, if the anticipated contingency is materially larger or smaller than expected, AEMO may alter the dispatch of individual generators within the quantity of generation Synergy is cleared to run.

Synergy's offers are not tied to the output of individual generators, and changes in their dispatch do not attract a constrained on or a constrained off payment. Their revenue is locked

[26] Out-of-merit refers to where a generator's offer price capped by their marginal production cost exceeds the market clearing price.

to their offer, but their operating costs are subject to change. Synergy has less opportunity to revise its pricing than other market participants due to its longer lead time on gate closure.

Synergy can be cleared to supply a given quantity of energy, but AEMO may substitute Synergy's generators that are scheduled to operate within the cleared quantity of capacity to maintain system security.[27] This may occur if the generators online cannot increase or decrease their output fast enough to provide the reserve required. Such substitutions would not trigger constrained-on payments unless Synergy's overall cleared quantity increased. These out-of-merit costs now comprise the bulk of load rejection reserve and spinning reserve costs.

Market dynamics are changing the costs to provide the spinning reserve ancillary service. Where past modelling identified foregone revenue as the main driver of spinning reserve cost, the low balancing market price means that out-of-merit costs now drive the spinning reserve cost.

The same circumstances that result in generators operating out-of-merit to provide spinning reserve also increase the load rejection reserve cost. Low-cost coal-fired generators (Collie and Muja power stations) are no longer able to be available to provide this service much of the time at zero marginal cost. That role is increasingly undertaken by higher-cost gas-fired generation. The lower the balancing market price – particularly where the price is negative – the higher the cost to provide load rejection reserve and spinning reserve ancillary services.

In submissions to the issues paper, Bluewaters Power, NewGen Kwinana Power and Synergy agreed with the ERA's assessment of the changing market conditions. Perth Energy disagreed that market conditions had changed as much as the ERA's modelling suggested.[28]

4.2 Sensitivity analysis

Given the additional quantity of gas-fired generation scheduled out-of-merit to provide ancillary services, the ERA tested the sensitivity of ancillary services costs to changes in gas price. Ultimately, the gas price sensitivity had a relatively modest effect on average balancing prices over 2021/22, a six per cent change in each direction. The observations for each gas sensitivity are summarised below:

- A low gas price resulted in slightly higher overall balancing market prices. A lower gas price reduced the difference in the fuel input prices between gas-fired and coal plant, making gas more competitive with coal. The WEM model seeks to minimise overall operating costs and so favours generators, typically gas-fired generators, with faster ramp rates and the ability to provide more than one ancillary service. The combination of a lower gas fuel cost and the flexibility in how gas-fired generators can be used, meant less coal was scheduled. With more gas-fired facilities in the generation mix, balancing prices were higher.
- When the gas price in the model was increased, coal generation became more competitive and its output increased. The lower operating costs of coal plant, compared to gas generation, slightly lowered balancing market prices.

[27] For example, if Synergy is cleared to run 500MW of generation capacity, this could be met with their least cost or their highest cost generators independently of the price settlement process. Consequently, AEMO may substitute output from a relatively low-cost generator like Collie or Muja with relatively high-cost generators such as Pinjar or Kemerton power stations.

[28] Perth Energy, 2021, *Determination of margin values and cost_LR parameters for 2021/22*, P. 3, (online)

The ERA also conducted sensitivity analysis on the solar uptake rate. The ERA found that different levels of rooftop solar affected the number and severity of negative price events in the balancing market.

The solar uptake rates used in the sensitivity analysis were equivalent to the high and low solar uptake levels in the 2020 Electricity Statement of Opportunities.[29]

Reducing the quantity of rooftop solar in the WEM model reduced the incidence of prices below zero and especially the number of intervals where the balancing price cleared at the floor. Overall, projected average balancing prices in 2021/22 increased by eight per cent.

Increasing the quantity of rooftop solar increased the incidence and severity of low and negative prices. In this sensitivity, average balancing prices decreased by 30 per cent.

Different levels of rooftop solar also influenced the dispatch of coal-fired generation and the availability cost of load rejection reserve during peak periods. Lower levels of rooftop solar increased demand for electricity from the network and allowed greater room for coal to operate. Under the low rooftop solar sensitivity, the quantity of load rejection reserve provided by coal plant was consistently higher for most hours of the day when compared to the high solar sensitivity. This is because coal, which has lower operating costs, tended to be in merit more often in the low solar scenario. With more low-cost coal plant providing load rejection reserve there was a lower cost of load rejection reserve during peak periods. The load rejection reserve availability cost was substantively the same for off-peak periods.

Higher levels of rooftop solar reduced demand for electricity from the network and further reduced balancing prices in the middle of the day. Higher levels of rooftop solar placed greater downward pressure on coal generators and increased the quantity of spinning reserve needed to cover the north country contingency. This is because the contingency assumes that 10 per cent of the rooftop solar output will be lost when the north country transmission line trips. The higher the quantity of rooftop solar present in the market, the higher the spinning reserve contingency amount.

Rooftop solar generation continues to increase, and it is likely that the generation levels assumed in the high solar sensitivity scenario will be reached at some point, leading to further decreases in demand from the network. As a result, negative prices and prices at the floor are expected to occur more frequently. Currently, some generators bid at the floor price or well below their short run marginal cost to ensure that they are dispatched. If balancing prices reach the floor more often, these generators are more likely to be dispatched and make a loss. This could prompt changes in their bidding behaviour, but these changes are difficult to model because factors other than short-run marginal cost (for example, contractual obligations) also influence bidding. So, while rooftop solar generation may reach the levels in the high solar sensitivity scenario, the effect on prices may be less marked than the model predicts.

4.3 Suitability of the margin value remuneration mechanism

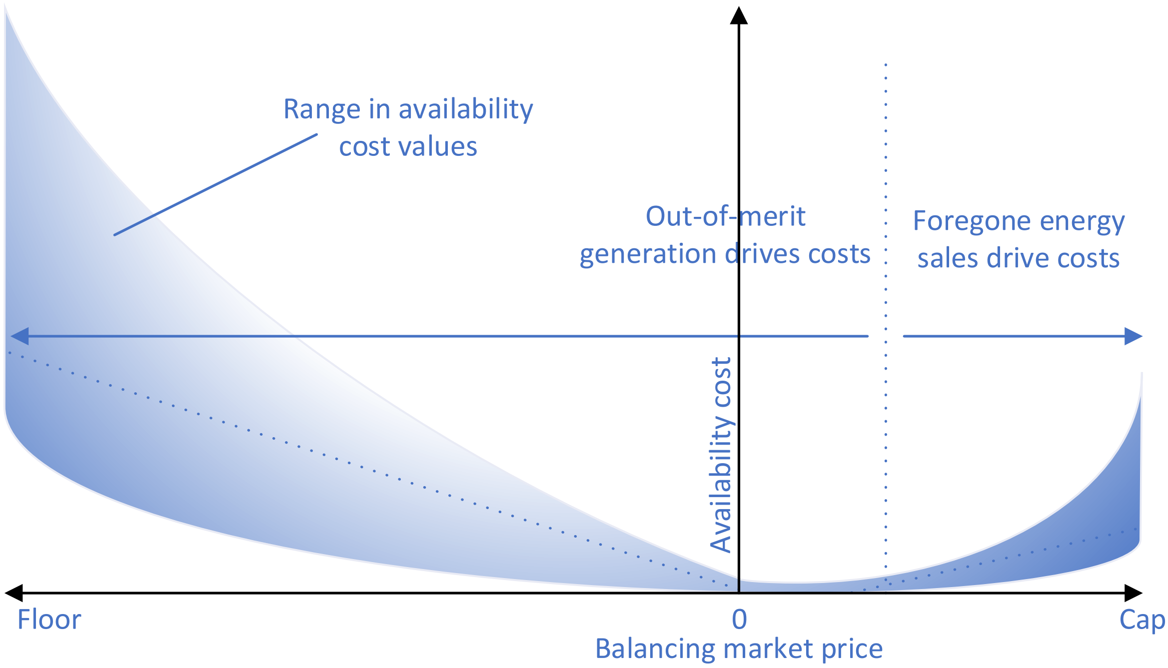
As explained in section 2.1.1, Synergy's cost to provide spinning reserve is recovered via multipliers (the margin values for peak and off-peak) that are applied to the balancing market price and the quantity of spinning reserve modelled for the period. The design of the margin value remuneration mechanism assumes a positive relationship between the cost to supply spinning reserve and balancing prices in the WEM. Historically, as balancing prices increased,

[29] AEMO, 2020, *2020 Electricity Statement of Opportunities*, chapter 4.2, (online)

the cost of spinning reserve tended to increase (although not necessarily proportionately). Synergy foregoes revenue to provide spinning reserve and therefore should be compensated.

Demand substitution to rooftop solar and the increase in low-cost generation participating in the market are lowering balancing prices. The relationship between the margin values percentages and energy prices now resembles a bathtub or “U” shaped curve and spinning reserve costs now predominantly accrue when balancing prices are low or negative (Figure 4).

Figure 4: Ancillary service costs vs balancing market price



The shape of the distribution is likely to be sensitive to overall demand and the flexibility within the system to accommodate large generators that can set the spinning reserve requirement. However, the modelled outputs reflects a shift in the major driver of ancillary service costs from foregone energy sales (such as occur when the spinning reserve provider is in merit) to out-of-merit costs (which occur when prices are low or negative).

The ERA’s modelling forecasts an increase in the incidence of negative pricing in the balancing market for 2021/22. Negatively priced intervals have increased from less than 50 intervals in 2016/17 to more than 500 in 2019/20. To the end of February 2021, 2020/21 has had nearly 1,100 negatively priced intervals. The ERA’s modelling indicates this may exceed 3,700 intervals in 2021/22. When prices are negative, two things can occur:

1. The marginal cost of generators scheduled to provide ancillary services needed to keep the system secure will remain positive even when the balancing market clears below zero. Consequently, there will be an increased quantity of generation run out-of-merit to provide the ancillary services and the cost of those services relative to the balancing price would increase.

2. Under the market rules, margin values cannot be multiplied by a negative balancing price when compensating Synergy for providing spinning reserve. There are enough negatively priced intervals occurring to affect Synergy’s spinning reserve revenue using margin values.

This increases the availability cost where generators are providing spinning reserve and/or load rejection reserve and not load following ancillary services. This means the minimum generation quantities cannot be recovered through other mechanisms. The margin values themselves need to account for the incidence of negatively priced intervals to ensure that Synergy is appropriately compensated for the provision of spinning reserve.

Changes in the load profile have substantially reduced prices and daytime negative prices are now a common occurrence. Where this occurs, the driver for spinning reserve is out-of-merit costs incurred when large coal and gas generators are operating at or just above their minimum stable generation threshold. This means the relationship between balancing price and the cost to provide spinning reserve has reversed and is now an inverse relationship. Now, as prices decrease, costs rise and as prices rise, costs decrease. The ERA has considered this change when determining margin values to apply in 2021/22. The approach taken by the ERA is outlined in section 5.4.

The mechanism to remunerate Synergy for providing spinning reserve is no longer suitable. This might be tolerable for a single year of operation, until the new market design is introduced in 2022, noting that the risks of over- or under-compensation have changed because of the changing generation mix and the uptake of substitutes for market-supplied electricity. The reforms currently underway in the WEM will establish a new essential system services market. The provision of energy and essential services will be co-optimised under security constrained economic dispatch. At this point the current margin value mechanism will no longer apply. However, if the introduction of the new essential system services market is delayed, then Energy Policy WA should consider amending the margin values administered system as it is no longer suitable.

5. The ERA's determination of spinning reserve and load rejection reserve parameters

For 2020/21, the ERA approved margin values of 25.46 per cent for peak periods and 21.42 per cent for off-peak periods, and spinning reserve quantities of 252 MW for peak and 240 MW for off-peak. These parameters were consistent with a spinning reserve availability cost of $8.4 million. The ERA approved a load rejection reserve cost of $1.2 million. The combined cost of spinning reserve and load rejection reserve for 2020/21 was $9.6 million.

Section 4 describes how market dynamics are influencing the quantities and forecast costs of spinning reserve and load rejection reserve. Consequently, the combined forecast costs for these two ancillary services in 2021/22 have increased to $13.9 million, an increase of 45 per cent. This change is driven by the availability of large quantities of renewable generation, rooftop solar in the middle of the day and wind from midnight to dawn, that is lowering balancing prices at these times. In response, large coal plants reduce their output, which gives them less room to provide load rejection reserve. Large coal generators are unable to quickly increase their output and this low ramp rate limits their ability to provide spinning reserve. AEMO needs to schedule generation out of the balancing merit order to maintain the ancillary service requirements. With low balancing prices and higher marginal cost plant providing ancillary services out of the merit order, the cost that needs to be met through ancillary service payments is greater.

The margin values need to allow for the recovery of the expected efficient availability cost of providing spinning and load rejection reserves. The ERA's forecast spinning reserve quantity needs account for any upwards LFAS that substitutes for spinning reserve and is separately compensated. Margin values also needs to compensate for the large number of intervals where the price is expected to be less than zero.

As noted in section 1.1, the ERA must determine margin values and Cost_LR parameters. The ERA is not obliged to approve AEMO's proposed values. To make its determination the ERA must take into account:

- Any stakeholder feedback received in response to the ERA's issues paper and addendum to the issues paper.
- AEMO's proposal, which must take account of the margin Synergy could reasonably have been expected to earn on foregone sales and the loss in efficiency of Synergy's scheduled generators.
- The wholesale market objectives.

These are discussed separately below.

5.1 Stakeholder feedback

Three stakeholders provided feedback on the suitability of AEMO's proposal for determining margin values and Cost_LR parameters to apply in 2021/22. Bluewaters Power, NewGen Power Kwinana and Perth Energy suggested that the ERA should accept AEMO's proposal to roll over the margin value and Cost_LR parameters from 2020/21 for 2021/22.

Bluewaters Power and NewGen Power Kwinana expressed concern over the "volatility of modelling outcomes that have been published throughout the margin values determination process."[30] These two generators suggested not changing spinning reserve and load rejection reserve costs because the "causes are not yet fully understood and that further time taken to understand causality would likely lead to a more accurate outcome."[31]

There were differences in spinning reserve and load rejection reserve indicative costs between the ERA's margin values and Cost_LR 2021/22 issues paper and subsequent addendum. All changes between the issues paper and addendum were the result of the ERA receiving new information or data to inform its determination. The issues paper explained that the ERA was:

- Continuing to work with AEMO and Western Power to include AEMO's increased spinning reserve requirement, identified in January 2021, into the determination process.[32]
- Seeking additional information from Western Power on the operation of the Generator Interim Access tool and how best to integrate it into the modelling.[33]
- Following up with generators who had not responded to the ERA's request for data, so that the most current generator and market data could be used in the determination.[34]

Once the ERA had received this additional information it published an addendum to keep market participants informed of progress as the ERA worked toward its final determination.

Perth Energy stated:

> The ERA's provisional outputs are materially different to those produced by the more robust ERA-approved modelling conducted for 2020/21, and have since been corrected to account for omissions in the ERA's standalone modelling exercise.[35]

As noted in section 1.1, the market rules do not require the ERA to approve any modelling underlying AEMO's proposal. Instead the ERA has to take AEMO's proposal into account when making its determination. As noted above, although there were differences in the indicative ancillary service values between the ERA's issues paper and addendum, these were the result of the ERA receiving new information or data to inform its determination.

Perth Energy questioned the "veracity of the ERA's modelling" and suggested that greater confidence should be placed on AEMO's outputs.[36]

AEMO and the ERA have different information-gathering powers. When undertaking modelling in support of its proposed spinning reserve and load rejection reserve cost, AEMO must rely on voluntary information collected from market participants. For its modelling, the ERA was able to collect confidential data from market participants under the market rules.[37] Using confidential data limits the transparency of the ERA's information gathering process but individual market participants were consulted on the input assumptions and modelled heat rates for their generators.

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[30] Bluewaters Power, NewGen Kwinana, 2021, *Response to issues paper – Ancillary service costs – spinning reserve, load rejection reserve and system restart (margin values cost_LR) for 2021/22*, P. 2. (online)

[31] Ibid. P2.

[32] ERA, 2021, *Ancillary service costs – Spinning reserve, load rejection reserve and system restart (Margin Values Cost_LR) for 2021/22 – issues paper*, PP. 12-13, (online)

[33] Ibid. P. 31.

[34] Ibid. P. 32.

[35] Perth Energy, 2021, *Determination of margin values and cost_LR parameters for 2021/22*, P.1. (online)

[36] Ibid. P.2

[37] Wholesale Electricity Market Rules, 1 February 2021, rule 2.16, (online).

The costs of spinning reserve, load rejection reserve and system restart services are recovered from market participants such as Perth Energy and Bluewaters Power. AEMO's proposed combined cost of spinning reserve and load rejection reserve, $9.6 million, is less than the ERA's forecast of $13.9 million. Ancillary service costs have been increasing over recent years and the ERA understands why participants would support keeping ancillary service costs as low as possible.

Section 4 explained how market changes are increasing ancillary service quantities and costs. The ERA's determination must ensure Synergy is compensated for the efficient cost of providing these ancillary services. The market rules require the ERA to determine input parameters for the recovery of spinning reserve costs from market participants. However, these rules do not allow the ERA to alter the allocation of costs to different market or customer segments.

Synergy's submission supported the ERA's forecast cost of spinning reserve and load rejection reserve and stated:

> At $13.9 million, the proposed SRAS and LRR costs are collectively more appropriate and cost-reflective to 2020/21 margin values currently in force and therefore recommends that the ERA approves the overall SRAS costs and Cost_LR parameters.[38]

Synergy stated that AEMO's proposal:

> Remains unduly low at $9.6m and does not take into account the recent changes to market dynamics and increased spinning reserve requirement resulting from escalating penetration of solar PV and network contingency.[39]

5.2 AEMO's proposal

In its determination of margin values and Cost_LR to apply in 2020/21, the ERA expressed concern with some aspects of AEMO's modelling approach, such as using back-casting to simultaneously validate the model and identify primary input assumptions.

> AEMO simultaneously sought to validate the model and identify primary input assumptions. Using a starting point from a media report, AEMO adjusted Synergy's and other generators' fuel prices through an iterative calibration process to arrive at modelled outcomes resembling real world market outcomes for the 2018/19 financial year.
>
> This process set Synergy's delivered gas cost to $3.50/GJ and reduced gas and coal prices provided by other major market generators by 40 per cent, compared to the values submitted or provided in previous years. The process also set the load-independent variable operation and maintenance cost to zero for Cockburn, Kwinana GTs, Muja, and Collie generators.[40]

AEMO's approach to setting fuel prices meant that, for 2020/21, the ERA could not support a proposal that was based on a Synergy fuel price that "does not appear to have a justifiable

[38] Synergy, 2021, *Ancillary service costs – spinning reserve, load rejection reserve and system restart (Margin values Cost_LR) for 2021/22*, P. 2, (online)

[39] Ibid. P. 3.

[40] Ibid. P. 9

basis nor does the method for its derivation."[41] The input costs for other generators collected through the initial consultation process were not used by AEMO's consultant in its modelling.[42]

The ERA based its determination of margin values and Cost_LR for 2020/21 on one of the fuel price sensitivities AEMO conducted as part of its proposal.

> 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.[43]

In its determination of margin values and Cost_LR parameters for 2020/21, the ERA had sufficient concerns with AEMO's modelling to disregard the base case underpinning AEMO's proposal and instead base the determination on the "best fit amongst the options presented."[44]

Furthermore, AEMO's proposal for ancillary service parameters to apply in 2021/22 was based on input assumptions and modelling outputs gained in 2019. For the margin values and Cost_LR 2021/22 determination, the ERA assessed whether AEMO's 2019 modelling assumptions included in its proposal were valid in 2020/21 and would remain valid for 2021/22.

The ERA found that this was not the case and Table 2 lists several market parameters and modelling input assumptions that have changed between 2019 and 2021.

Table 2: Differences in market parameters and market outcomes 2019 to 2021

Item	Assumptions in 2019 underpinning AEMO's proposal	Revised assumptions used in the ERA's determination
Spinning reserve quantity	The largest spinning reserve contingency modelled was the tripping of the 330kV north country transmission line and losing the generation connected to that line or 70 per cent of the largest output from a single generator.	**A higher spinning reserve quantity.** In January 2021, AEMO advised that it was increasing the spinning reserve quantity by between 70MW and 130MW, an increase of 30 to 50 per cent. This increase is to recognise the disconnection of a proportion of rooftop solar systems when the 330kV north country transmission line trips.

[41] Ibid. P. 15

[42] Ernst and Young, 2019, *Ancillary services parameter review: Final report, AEMO*, P. 22, (online)

[43] ERA, 2020, *Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21*, PP. 6-7, (online)

[44] Ibid. P. 11

Item	Assumptions in 2019 underpinning AEMO's proposal	Revised assumptions used in the ERA's determination
LFAS quantity	AEMO assumed LFAS quantities of 116 MW between 5.30am to 7.30pm and 70 MW at all other times. This was to allow for an expected increase in the variability of demand and intermittent generation. During 2020/21, AEMO deferred increasing the LFAS quantity and in practice has not procured more than 95 MW from the market.	**A higher LFAS quantity.** In late January 2021, AEMO advised the ERA that AEMO was likely to increase LFAS quantities to a range of 106 MW to 120 MW for daytime periods. The ERA included this changed LFAS quantity into the modelling for the determination. The ERA's modelling also captured the behaviour of third party LFAS providers who tend to withdraw from the LFAS market during the afternoon ramp period.
Wind farm output	AEMO's consultant used historical data (where available) and made assumptions about the likely output of two new windfarms, Yandin and Warradarge that were expected to become operational during 2020/21.	**Warradarge wind farm is operational and Yandin will be operational shortly.** ERA used actual output data for these and other wind farms (where available). If operational data was not available the ERA used estimates prepared by AEMO accredited independent experts engaged by the wind farms to provide output estimates for the capacity certification process.[45]
Constraints on wind farm output	AEMO's consultant did not model the generator interim access (GIA) constraints in the 2020/21 modelling.	**GIA constraints on wind farm output were modelled.** In conjunction with AEMO and Western Power, the ERA has considered the operation of the GIA constraint: what combination of generators are affected by the constraint, and when the constraint binds. This approach ensures there is a better fit between the output from GIA generators in the model and the output from these generators in the market.
Number of negative balancing price intervals	AEMO's consultant forecast approximately 1,000 intervals with a price below zero for 2020/21.	**A higher number of intervals with negative wholesale prices.** At the end of February 2021 there had already been 1,100 negative price intervals in the WEM. The number of negative pricing intervals is forecast at 3,700 in 2021/22 or around 21 per cent of intervals. Negative balancing prices are a major contributor to ancillary service costs.

45 A list of certified accredited independent experts is available on the AEMO website online.

Item	Assumptions in 2019 underpinning AEMO's proposal	Revised assumptions used in the ERA's determination
Generator input data	Data collected in 2019 from generators on a voluntary basis. Many of the input assumptions collected from were overwritten during the consultant's back-casting process. • Gas and coal prices provided by other major market generators were increased by 40 per cent. • Load independent variable operating and maintenance costs were set to zero for Cockburn, Kwinana GTs, Muja and Collie generators Changing input assumptions in this way changes a generator's offer curve and can affect the generation mix dispatched into the market.	**More up-to-date data.** The ERA collected data from generators under market rule 2.16 and used publicly available market standing data. The modelling input assumptions for individual generators including heat rates, operation and maintenance costs and commitment and decommitment costs and other physical performance characteristics were collated provided back to generators for verification in January 2021. Two generators, Alinta and Synergy provided updated inputs too late to be included in the issues paper modelling. This data was included in modelling underpinning the addendum. **All data received from generators was used in the modelling.** The ERA adjusted portions of the cost curve derived from market participants to account for capacity offered at the market caps. This approach ensured the underlying modelled generator costs better reflect the basis on which market participants derive their offers. The currency and accuracy of information will yield more accurate results.
Forecast gas prices	AEMO's back-casting process set Synergy and other market participants delivered gas price to $3.5/GJ.	**Updated gas price information**. The ERA used: • The last gas price information Synergy provided when the ERA undertook its model validation process. • A forecast gas price for Synergy based on publicly available information. Since 2019, the wholesale gas market has tightened and spot gas prices have increased. The Synergy gas price used in the ERA's modelling for 2021/22 was higher than either of the gas price assumptions $3.50/GJ or $5.25/GJ considered in 2020/21. Sensitivities were also conducted around gas prices.

Item	Assumptions in 2019 underpinning AEMO's proposal	Revised assumptions used in the ERA's determination
PV uptake	AEMO's solar uptake assumptions are based on those from mid-2019.[46]	**Updated rooftop solar uptake data.** The ERA has used solar assumptions from the most recent Electricity Statement of Opportunities. The effect of rooftop solar on electricity demand emerged through the modelling as having a major influence on the cost of ancillary services. The ERA conducted sensitivities around this to ensure the influence of falling demand on pricing outcomes was thoroughly understood

Source: AEMO margin value and Cost_LR proposals for 2020/21 and 2021/22 and ERA modelling

The effect of the changes listed in Table 2 on the forecast costs of spinning reserve and load rejection reserve show that the inputs and modelling underlying AEMO's proposal are no longer valid. The ERA instead has forecast spinning reserve and load rejection reserve parameters based on the best and most current information available.

5.3 The wholesale market objectives

The wholesale electricity market has five objectives.

These are to:

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

Most of the market objectives are not directly relevant to this determination. Reliability and security objectives are met through the ancillary service quantities, standards and requirements that are established by other mechanisms. For example, quantities of spinning reserve and load rejection reserve are established through the annual ancillary services requirement report, which the ERA approves.

The margin values and the "L" component of Cost_LR market settlement parameters are primarily concerned with Synergy's remuneration for the ancillary services it provides. Setting an appropriate price for the services provided is important to support the market objectives of

[46] Ernst and Young, 2019, *Ancillary services parameter review: Final report, AEMO*, P. 22, (online)

minimising long-term costs to consumers and fostering competition. Managing end-user demand and avoiding discrimination are not relevant to the determination.

The ERA's approach has been to use the best available data as the basis for the modelling underlying its determination of ancillary service parameters to apply in 2021/22. The modelling outputs demonstrate the substantial changes in the market caused by increasing penetration of renewable generation. The ERA's approach supports the economically efficient identification and allocation of costs across the market and, to the extent that it is feasible, emulates the effects of competition for services through co-optimised scheduling where none currently exist. Noting the disconnection between what is driving the cost of spinning reserve and the recovery mechanism itself, the ERA considers that the process used to identify the values in this determination meets the market objectives of minimising long-term costs of electricity supply to consumers, encouraging competition and promoting the economically efficient, safe and reliable supply of electricity in the SWIS.

Synergy has suggested that using a co-optimised modelling approach to determine ancillary service costs has contributed to Synergy being undercompensated for supplying ancillary services.[47]

> Synergy disagrees that there is no incremental cost involved for the provision of SRAS [spinning reserve ancillary service] when simultaneously providing LFAS and notes this may be true only when modelling with the benefit of perfect hindsight, which enables perfect dispatch of facilities required for ancillary services.
>
> In reality, dispatch needs to account for consumed LFAS and where consumption of LFAS leaves insufficient headroom to accommodate SRAS, an additional unit may be required.
>
> Dispatch decisions are further complicated by inaccuracies in the balancing price forecasts and co-optimisation does not currently exist in the WEM. Instead, uncertainty in the market may give reason to schedule multiple facilities for the provision of ancillary services, whereas with the benefit of hindsight, less facilities may have been required to service requirements.

The quantity of LFAS provided by Synergy's generators is not recorded and the ERA is not party to the planned scheduling of facilities agreed between AEMO and Synergy.[48] Therefore, it is difficult to confirm Synergy's claim that, in practise, more generators are scheduled than would be indicated by the modelling.

5.4 Setting the margin values

As discussed in section 4.3, the margin value mechanism used to remunerate Synergy for providing spinning reserve is disconnected from the drivers of spinning reserve costs. However, this is not the only problem with the margin value mechanism.

In the market rules, the calculation that utilises margin values to compensate Synergy for spinning reserve cannot accommodate negative balancing market prices. In trading intervals with negative balancing prices, the spinning reserve remuneration calculation sets the balancing price to zero and Synergy does not receive any compensation for providing spinning reserve. In trading intervals where balancing prices are positive, Synergy is compensated.

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47 Synergy, 2021, *Ancillary service costs – spinning reserve, load rejection reserve, and system restart (Margin values cost_LR) for 2021/22*, P. 3, (online)

48 AEMO (2018) Ancillary service report for the WEM 2018-19, PP. 23-26, (online)

Therefore, Synergy is no longer always compensated for providing spinning reserve at the same time that Synergy is incurring a cost to provide the service. As the number of negatively priced trading intervals in the WEM increases the greater is the number of intervals where Synergy incurs a spinning reserve cost but is not compensated for providing the service.

The ERA has considered the problems with the margin values mechanism when determining margin value percentages to apply in 2021/22. The margin value mechanism is unable to compensate Synergy every time it incurs spinning reserve costs. Therefore, the ERA has set margin values that ensure, over the 2021/22 financial year, Synergy will be compensated for providing spinning reserve. Although Synergy will not receive spinning reserve in the intervals when balancing prices are negative, the ERA has set margin values sufficient to remunerate Synergy adequately for all intervals when balancing prices are positive.[49] However, there are risks in taking this approach. If there are fewer negatively priced intervals than forecast, Synergy will receive more compensation (and less compensation if there are more negatively priced intervals).

5.5 Summary

After considering AEMO's proposal, stakeholder feedback and the market objectives, the ERA has determined the following margin values, spinning reserve quantities and load rejection costs to apply in 2021/22:

Table 3: Modelled spinning reserve quantities and ERA-determined margin values for 2021/22

	Unit	Peak	Off-peak
Margin value	%	12.6	23.2
Spinning reserve quantity	MW	240	241
Modelled values			
System average marginal price	$/MWh	20.51	25.07
Estimated Synergy availability cost	$m	3.040	3.494

Source: ERA modelling

Determining margin values when the remuneration mechanism is not suitable is not ideal. However, if the ERA accepted AEMO's proposed margin values for 2021/22, the risk of overcompensating Synergy would be even higher. AEMO's proposed peak margin value for 2021/22, 25.46 per cent, exceeds the value determined by the ERA, 12.6 per cent. So, if there are fewer negatively priced intervals than forecast in the ERA's modelling, a peak margin value of 25.46 per cent would exacerbate the over-compensation paid to Synergy. This is contrary to the desired outcome expressed in the submissions received from Perth Energy, NewGen Power Kwinana and Bluewaters Power.

Table 4: ERA-determined load rejection reserve cost (Cost_L) for 2021/22

Parameter	Unit	Peak	Off-peak
Load rejection reserve availability cost	$m	4.331	3.054

[49] The ERA used a solver function to estimate the proportion of the forecast balancing prices necessary to deliver the forecast availability cost over the year through only positively priced intervals.

Parameter	Unit	Peak	Off-peak
Cost_L – Total load rejection reserve	$m		7.386

Source: ERA modelling

6. The ERA's determination of system restart costs

For 2020/21, the ERA approved system restart costs of $2.868 million. This was $0.41 million lower than the $3.278 million proposed by AEMO. The ERA accepted AEMO's proposed system restart contract costs for the South Metropolitan and South Country sub-regions. For the North Metropolitan contract, the ERA had previously found the cost of this contract to be inconsistent with the market objectives. In its March 2019 determination of system restart costs to apply over 2019/20 to 2021/22, the ERA identified that, for the North Metropolitan contract:

> Pricing was not based on the cost to provide a system restart service or the cost recovery of the capital and operational costs necessary to provide the service. Instead the contract was based on the revenue needed to be recovered through the contract to ensure a return on investment of around 5 per cent. This transferred market risks from the balancing market and reserve capacity mechanism onto the system restart contract.
>
> In the ERA's 2016 determination, this pricing strategy was determined to be inconsistent with the market objectives and was rejected. Instead, the ERA applied Consumer Price Index to the previously proposed contracts.[50]

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 reflected the service provided.[51] The ERA's suggestions included:

- Reviewing the procurement process and prescriptive requirements to make it more outcome-focussed and encourage 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 a request for expressions of interest for providers in the North and South Metropolitan areas without prescriptive requirements on how the service should be met.[52]

6.1 AEMO's proposed value

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.[53]

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. At the time of publication, AEMO is coming to the end of a process to procure new system restart service contracts for these two sub-network areas. AEMO's proposal

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50 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*, PP. 26-27 (online)

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

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

53 ERA, 2020, *Decision on the Australian Energy Market Operator's 2020/21 Ancillary Services requirement*, P. 9, (online)

provided the ERA with indicative contract pricing from the two possible system restart providers.

In November 2020, AEMO proposed a new system restart cost of $3,369,438 for 2021/22. This is 17 per cent higher than the system restart cost approved for 2020/21 and is based on the proposed tender pricing provided for the North and South Metropolitan areas as well as the existing service contract for the South Country Area adjusted for inflation according to the contract terms.

6.2 The ERA's determination

The Cost_LR parameter represents the combined costs of load rejection reserve and system restart services. Synergy is the default provider of load rejection reserve, whereas system restart services can be provided by Synergy and third parties.

The competitive procurement for system restart services is particularly challenging in the WEM given the small size of the market, which is exacerbated by the requirement for geographic diversity in the provision of the system restart service.[54]

The market rules include a mechanism, the shortfall charge, that enables AEMO to recover costs from retailers, if system restart costs exceed the system restart costs approved by the ERA. The shortfall mechanism limits the benefit of regulatory oversight as it does not prevent AEMO entering contracts at prices that exceed the cost to provide the service. It also allows the costs of such contracts to be recovered from the market. As noted by Perth Energy in its submission, the effect of the shortfall charge where a contracted cost is considered greater than the efficient or justifiable cost is problematic.[55]

If a contracted system restart cost exceeds the amount approved by the ERA, the difference would first be deducted from the Cost_LR sum. Any remaining shortfall is then recovered from the market. It also means that if the ERA determines that the cost of a third-party system restart contract exceeds the efficient cost of providing the service, the difference would come first from the pooled sum for both system restart and load rejection reserve. This would result in a transfer from Synergy's load rejection reserve remuneration to a third party's system restart contract, leaving Synergy undercompensated.

[redacted]

54 In previous determinations to improve the procurement exercise, the ERA recommended AEMO require service proponents to provide a cost breakdown of their prices to enable verification of the individual cost elements. AEMO has advised the ERA that it implemented this recommendation in the current procurement process.

[redacted]

Like the margin values, this is another example of an ancillary service compensation mechanism being unsuitable, although this is the last time this mechanism will apply to the load rejection reserve costs. From October 2022, system restart costs will form part of the new Essential System Services mechanism introduced as part of the State Government's energy reform program. Nevertheless, the effect of the shortfall charge and regulatory oversight of system restart service is likely to remain.

To make its decision on the 'R' component of Cost_LR, the ERA reviewed information provided by AEMO, which AEMO considers to be commercial-in-confidence and will remain confidential as per the WEM Rules. After considering AEMO's proposal (noting the shortcomings in the market rules discussed above), stakeholder feedback and the market objectives, the ERA has determined the following value for the system restart service cost to apply in 2021/22:

Table 5: ERA-approved system restart costs (Cost_R) for 2021/22

Parameter	Value ($)
Cost_R - System restart	3,369,438
Cost_LR	10,755,619

Appendix 1 The ERA's modelling process

Modelling process

The modelling was undertaken using a three-stage process consisting of back-casting and model calibration, forecasting, and post modelling processing. The steps and decision process is outlined in Figure A 1 below.

The first stage was calibrating the model to a known time-period based on input assumptions understood to be in use at the time. Once the model satisfactorily yielded outputs analogous to the real market the input assumptions were updated for the forecast period.[56] Several models were developed and have undergone gradual incremental improvement. Model iterations included revisions to:

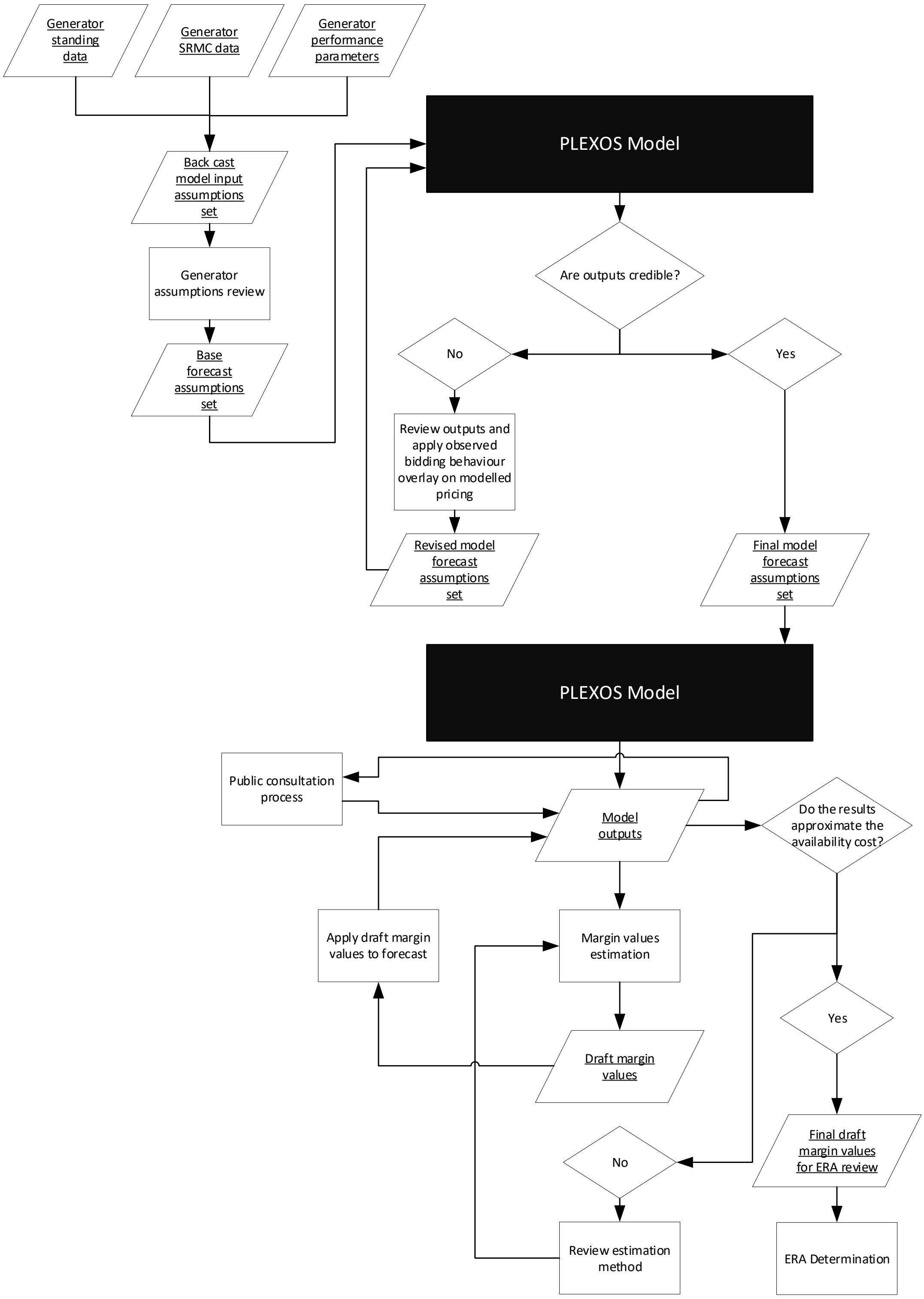
- The heat rate curves.
- Modifications to the offer curves to reflect generation capacity that is made available in the market and capacity that is bid below the marginal cost of generation (termed mark-ups).
- Modifications to the dispatch status of some generators.[57]
- Ancillary service requirements.
- The outputs of selected wind generators.
- Generator data that came in during the modelling process,

Sensitivity analysis was conducted on generator input costs and the rooftop solar installed capacity and output.

[56] In a forecast model there will always be differences between the model and real market outcomes.

[57] Some generators can be deemed 'must run' reflecting a preference for generators to provide ancillary services or a tendency to bid below their marginal cost. One example is for cogeneration facilities which supply industrial facilities with heat and electricity output outside the market.

Figure A 1: Modelling process flow chart



Final Adjustment Model

In the final step, some additional changes were included:

1. Modelling the unavailability of some extra baseload units.[58]

2. For some baseload/must-run units a minimum load was defined. This step amended the initially hard-coded unit commitment (must-run in any case), which now allows the model to shutdown these units in low demand intervals.

3. Further refinement of some units' running cost over the whole year (2021/22).

These refinements improved the dispatch and price outcomes in the back-casting model. Figure A 2 shows the price duration curves for the final back-casting model and the actual generation comparison for the conventional units.

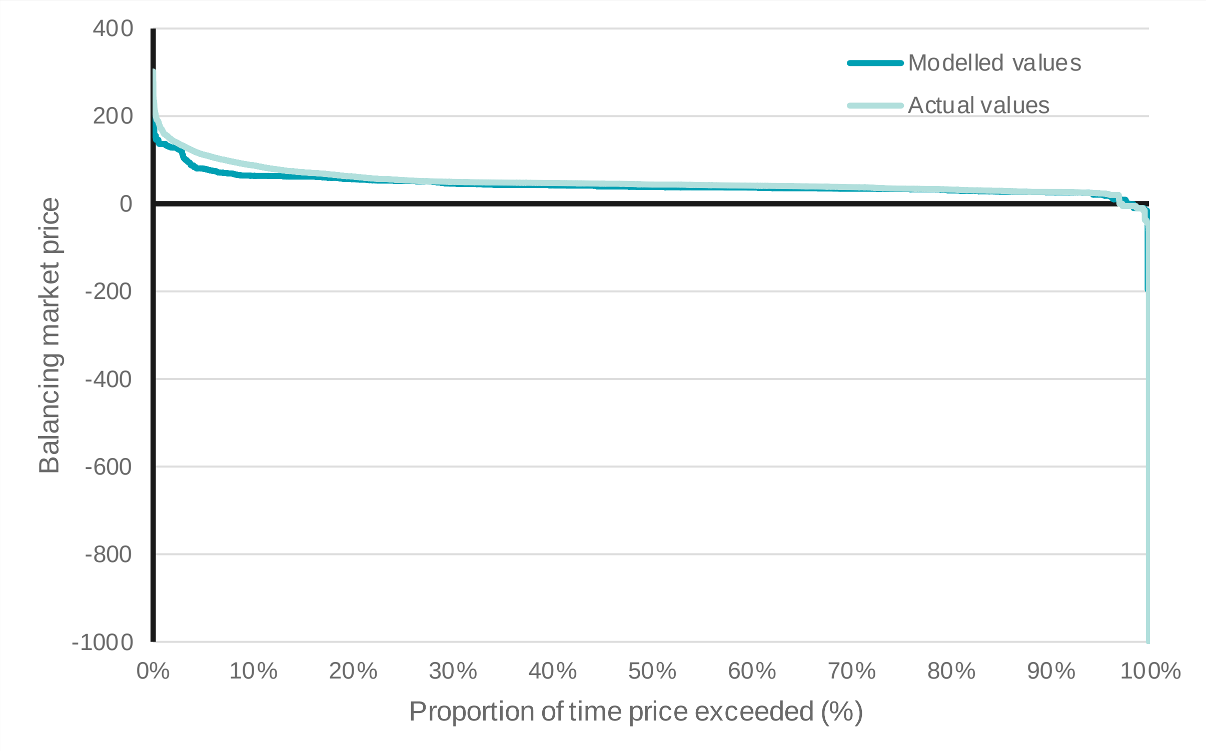
With the combination of original input data, assumed technical characteristic and bidding behaviour, including custom constraints based on historic operation of the facilities, the modelled prices and dispatch are sufficiently close to the actual values to consider the model calibrated.

The resulting prices are very close to actual for most of the year. However, in the higher-priced periods (above $60/MWh) the price difference between the modelled outcome and actuals can be in the range of $20/MWh to $40/MWh. For this reason, the model tends to deliver lower balancing market prices than the market.

A likely reason for the resulting price variance is the uncertainty in modelling the individual Synergy units that are treated in the model as a single facility (Portfolio). Also, the bidding behaviour of the non-Synergy generators is modelled to be the same during the whole year to get the overall results closer to actual. This does not consider changes in the bidding behaviour of these facilities in certain periods, or under specific circumstances.

[58] It was noticed during the quality assurance process that some generators were not dispatched in the market for two to three days at a time and yet not identified as an outage. Addressing the functional withdrawal from the market, improved the dispatch outcomes for these generators.

Figure A 2: Price duration curve for 2019/20 in the actual Vs back cast models



Source: AEMO data and ERA modelling

Sensitivity analysis

Sensitivity analysis was conducted around the two major drivers of the cost and scheduling outputs. There were the gas prices and demand reduction resulting from the uptake of rooftop solar.

Table 1 A below summarises the costing profiles for the different sensitivities conducted. Average positive prices across all sensitivities are similar. The exception is the low gas price sensitivity which is marginally lower than the other sensitivities. The number of negative prices are highest in the high solar sensitivity and the high gas sensitivity. However, the depth of the negatively priced intervals are deepest with the high solar sensitivity and shallowest with the low solar sensitivity.

Table1 A: Comparison of balancing prices from the sensitivity analysis

	Base case	Low-Gas	High-gas	Low PV	High PV
Balancing price (peak)	\$25.07	\$26.42	\$24.06	\$29.07	\$13.92
Balancing price (off-peak)	\$20.51	\$22.00	\$18.66	\$19.67	\$20.90
Average balancing price over full year	\$23.17	\$24.58	\$21.81	\$25.15	\$16.83
Number of neg trading intervals	3,744	3,253	4,012	3,570	4,015
Number of trading intervals with price less than \$-200	101	79	115	52	271

	Base case	Low-Gas	High-gas	Low PV	High PV
Number of trading intervals with price less than $-700	36	20	27	15	115
Number of trading intervals with price less than $-900	19	9	15	6	83
Average negative balancing price	-$37.15	-$33.38	-$36.23	-$30.85	-$59.53
Average negative balancing price in a range between $0 and $-200	-$25.98	-$25.02	-$26.65	-$25.57	-$27.51
Average positive balancing price	$39.56	$37.78	$39.04	$39.48	$39.52
Average positive balancing price (peak)	$42.86	$41.21	$42.17	$42.71	$42.69
Average positive balancing price (off-peak)	$34.53	$32.76	$34.10	$34.32	$34.89

Source: ERA modelling

Table A 2 summarises the availability costs for the different sensitivity analyses undertaken. The availability cost of spinning reserve and load rejection reserve was far more sensitive to gas price than the rooftop solar. The gas price is a major input to the cost of generation selected by the model to run out-of-merit when the spinning reserve is needed. This reflects the change in the fuel and operational costs across the sensitivity runs. The marginal shift in rooftop solar reflects the differences in the solar contingency that bind for parts of the day. The high solar scenario places additional pressure on the coal fired generation reducing their capacity to provide load rejection reserve. The provision of load rejection reserve in the high PV sensitivity from gas generators was higher than in the low PV sensitivity.

Table A 2: Comparison of spinning reserve and load rejection reserve availability costs from the scenario analysis

Cost ($m)	Base case	Low-Gas	High-gas	Low PV	High PV
Spinning reserve availability cost	6.5	4.3	9.2	6.6	6.7
SR Peak	3.0	2.0	4.6	3.1	3.5
SR Off-peak	3.5	2.3	4.5	3.5	3.3
Load rejection reserve availability cost	7.4	6.5	7.5	6.8	8.9
LRR Peak	3.0	2.0	3.0	2.5	4.5
LRR Off-peak	4.3	2.3	4.4	4.3	4.3

Source: ERA modelling.

Model configuration

The ERA has commissioned and developed a model of the wholesale electricity market using the PLEXOS modelling software. The software is a computer modelling package for physical energy systems and is widely used for modelling electricity markets. PLEXOS is configured to determine the least cost dispatch of generating resources to meet a given demand, against a set of constraints and defined properties for generation and network assets.

The WEM model has been configured to co-optimise electricity generation with load following ancillary services (LFAS), spinning reserve, load rejection reserve, and ready reserve. That is the model will identify the least cost means of meeting the energy requirements and the different ancillary service requirements. Based on this co-optimised dispatch, the WEM model forecasts balancing prices for each 30-minute interval.

The model draws from a database of fields that describe the physical characteristics and associated costs and operational constraints for generators connected to the South West Interconnected System (SWIS).

Market configuration

The WEM database includes four 'reserve' services for modelling spinning reserve, load rejection reserve, and both upwards and downwards LFAS. Overlap between reserves, such as between the upwards LFAS and spinning reserve is undertaken by the model when calculating the reserve requirement. In the modelling, tranches of generation capacity are dedicated to a single ancillary service. For example, assume a spinning reserve contingency risk of 300 MW, the model would set the spinning reserve requirement to 210 MW (70 per cent of the contingency). If the market had 100 MW of upwards LFAS, this would be deducted from the 210 MW requirement. The model would then optimise the scheduling of energy demand, 100 MW of upwards LFAS, and 110 MW of spinning reserve.

Spinning reserve contingency

Based on information provided by AEMO, the spinning reserve 'risk' or contingency was the larger of 70 per cent of the largest output from a single generator or the 'North Country contingency'. This was the loss of the combined output of Yandin, Warradarge and Badgingarra wind farms, less the Karara load plus 10 per cent of the estimated solar output in the SWIS, following the trip of the 330kV transmission line north of Perth.

In the model, generators were limited to providing no more than 30 per cent of the contingency quantity to reflect the need to spread risk across multiple generators and prevent the model selecting a single low-cost generator for ancillary service duty where in practice the spinning reserve response would not be sufficient or plausible.

Two contracts for spinning reserve are assumed to be in place for the duration of the forecast period with a combined capacity of 63MW.

Load following ancillary services

The upwards and downwards LFAS requirements in the modelling outlined in the ERA's margin values and cost_LR 2021/22 issues paper were set at 95 MW for daylight hours (5:30AM to 7:30PM) and 70 MW overnight. AEMO can increase the reserves to 106 MW for daylight hours or 80 MW overnight if needed. However, modelling inputs were originally based on the LFAS quantities that were applied through the LFAS market over the last year.

In the final modelling run the nominal LFAS requirement was increased from 90 MW in the original forecasting period to 113 MW being the mid-point in the range provided by AEMO. The overnight requirement remained at 70 MW.

Load rejection reserve

The load rejection reserve contingency is assumed to be 90 MW in the planning horizon in advance of the trading interval when the generating units providing the reserve are committed. In practice some wind farms automatically reduce their output when the frequency in the system exceeds a predetermined threshold – so more load rejection reserve can be available than was anticipated. However AEMO may have already committed scheduled generators out-of-merit to provide the load rejection reserve requirement.

Network configuration

The network is assumed to be generally unconstrained but with specific network constraints (such as apply under generator interim access contracts) separately modelled based on the observed application of the constraint tool developed by Western Power.[59]

Electricity demand

There was no half-hourly demand forecast available for 2021/22. The ERA took the last complete demand profile (2019/20) and adjusted this to align with AEMO's forecast peak demand, minimum demand and operational consumption indicated in the 2020 Electricity Statement of Opportunities.[60] PLEXOS then scheduled generation to meet the half hourly scaled load profile for each interval for the forecast 2021/22 period.

Rooftop solar forecasts were also based on AEMO's expected forecast. AEMO provided the ERA with a modelled half-hourly solar output profile. The ERA then scaled the solar output consistent AEMO's expected rooftop solar installation rate for 2021/22.[61]

Generator configuration

The ERA collected the physical and operational characteristics for each generator in the SWIS under Market Rule 2.16.[62] These include:

- fuel consumption rates (heat rates)
- operation and maintenance costs (load dependent and independent)
- generator commitment and decommitment costs
- fuel supply costs.

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[59] The network is modelled as a single node rather than multiple nodes with programmed constraints.

[60] AEMO, 2020, *2020 Electricity Statement of Opportunities*, (online).

[61] Ibid.

[62] Market rule 2.16 enables the ERA to collect data from market participants in support of the ERA undertaking its obligations under the market rules.

Market standing data was used to define:

- generator ramp rates
- minimum stable generation thresholds
- minimum time to synchronisation (cold, warm and hot)
- minimum down time.

Other information from the market surveillance data catalogue were used for

- forced outage rates
- historical bidding patterns
- historical market participation and generation patterns
- generator loss factors.

Fuel input costs

Fuel input costs were collected from market participants and scrutinised to ensure consistency with the short run marginal cost principles in the market rules and the opportunity cost of gas. Most generators' fuel input costs reflect spot market costs. The fuel input costs reflect a conservative estimate of the future spot market price for the forecast period.

Historical back-casting and model calibration was undertaken using actual fuel input prices provided by market participants. This was necessary to observe the extent to which the model output can reasonably reproduce actual market outcomes. Back-casting was used to calibrate and tune the market model. In order to do this, the input assumptions must reflect the actual input costs as closely as possible.

However, to forecast ancillary service costs for 2021/22, the ERA must include assumptions on forward fuel prices. These assumptions were based on publicly available fuel price information. Sensitivities were conducted around the fuel price by +/- $1/GJ.

Heat rates

Heat rates are a measure of a generator's efficiency. It is the energy content of the fuel needed to produce a given output quantity. The heat rates determine the fuel-related operating cost of a generator. Marginal heat rates reflect the incremental change in fuel required to generate an additional unit of output.

Generators provided the ERA with their heat rate curves when requested under market rule 2.16. Using the heat rates the ERA calculated marginal heat rate to enable the WEM model to simulate generator dispatch – this step helps reduce the modelling run time.

As Synergy bids as a portfolio, its offer tranches are not explicitly connected with particular generators. To overcome this, load points for Synergy's generators were evenly divided across the output range between minimum stable generation level and maximum output capacity. Convex marginal heat rates reduces the computational complexity of scheduling decisions. Where the derived marginal heat rate curve were not convex, the heat rates at non-convex load points were manually adjusted to make the curve convex. This is a relatively modest change to the accuracy of the heat rate but ensures the model functions within a reasonable time-frame and reduces the risk the software cannot find optimal generator schedules. Synergy provided adjustments for its generators.

Bid-cost mark-ups

The marginal costs for some generators were adjusted to account for historical bidding behaviour such as altering portions of the offer curve when generation is bid at the floor or below zero and or offered at the market cap. This bidding behaviour may reflect generator cycling costs (generators bid at negative prices or at the floor price to avoid being decommitted) or fuel supply constraints. However, these details are not transparent to the ERA.

Outages

The back-casting model runs used actual generator outages as a fixed input to the model. Coal generator economic decommitments in the back-casting period were treated equivalent to outages. For the forecast period, facility outages were modelled either as planned, or as unplanned outages. Unplanned outages are modelled as percentage of the unit's operating hours in a year and as a percentage of the total hours in a year through generators' forced outage rates. The modelling also accounts for partial outages through generators' partial forced outage rates.

Wind and solar generator output

Variable generators output is driven by resource availability. An output profile for generators is needed as an input to the model. In the back-casting model runs, actual wind farm or solar farm output was used as a fixed input to the model.

The WEM forecast used actual generation outputs, reprofiled where appropriate. New wind farms in the market have no or only limited operational data. For these wind farms, the ERA used the generation forecasts estimates that had already been prepared by independent, AEMO-accredited experts and provided by market participants for the capacity certification process.[63]

For GIA generators, there can be several constraints that have the possibility of limiting wind farm output in a single network region. The first constraint limited the total output of wind farms in the north country region. This was applied first to the forecast output of the wind farm prior to input into the PLEXOS model. The second set of constraints depends on the combined output of the wind farms with other generators connected in the region. This constraint was applied within PLEXOS and was developed with guidance from AEMO and Western Power.

Generator operational constraints

In the WEM model there are operational constraints to alter the behaviour or availability of generators. These constraint rules define specific operating rules or impose limits within the system and prevent unrealistic model outputs. For example, the tendency for non-Synergy generators to withdraw from the LFAS market from mid-afternoon into the evening. One virtual generator PORTFOLIO was also modelled to simulate Synergy's portfolio bidding.

Constraints were also applied to limit the ancillary service quantity any one facility can provide. These constraints impose an upper limit to the provision of up to 30 per cent of the spinning reserve and load rejection reserve risk. This approach ensures the diversification of resources in case a unit fails to perform or is physically unable to deliver the ancillary service in the required timeframe. Without such constraints, PLEXOS could schedule an unrealistic quantity

[63] These estimates are used in as inputs to the relevant level method for capacity allocation.

of capacity to an ancillary service reserve that the generator could not sensibly provide. For example, without a constraint the model could schedule 120 MW from a coal fired power station to spinning reserve which might take a full half hour to deliver – substantially below the six second to five-minute response time needed.

Differences between the model and the WEM

Models are inevitably a simplification of the real world. The WEM, although relatively small in comparison to international energy markets has several features that are complex to model. The scheduling of generators for example is not co-optimised, rather it is sequentially optimised (LFAS, then energy, then other ancillary services) with LFAS the only ancillary service determined in a market. Other ancillary services such as load rejection reserve and spinning reserve are manually scheduled without regard to pricing, rather they are set following a set of dispatch guidelines. This may result in higher prices than a co-optimised market.

To ensure generators are in merit to provide ancillary services and dispatched in the merit order, ancillary service quantities are bid at the floor (load rejection reserve and load following lower) or at the cap to ensure the upwards services are available (spinning reserve and load following raise).

The requirement to bid at the floor rather than at a generator's marginal rate is a market design feature to compensate for the lack of co-optimisation in costs across the different market services. However, the resulting pricing distortion posed some challenges for cost allocation and model calibration. Model calibration sought to provide a reasonable and accurate rendition of market outcomes and as a consequence the offer curves were altered to reflect this element of the market rules (see figure A 3 to figure A 17). In terms of allocating costs, the default calculation assumed the costs offered to the market (including mark-ups) reflect a generator's marginal cost. In these instances, the next positive offer was used as a substitute for the base offer which may have been subject to an ancillary service offer distortion. This results in a more realistic ancillary service cost rather than assuming the marginal cost is -$1,000 per MWh.

Manual scheduling is also a point of difference. Individual system management operators will have different approaches to managing system security, one operator may allow ancillary service reserves to ride through periods where they may be thinner than is ideal and another operator may choose to intervene and reschedule Synergy's generators to increase reserves. It is not possible to account for the individual operators' tendencies in generator scheduling and data is not available to model this stochastically.

AEMO schedules Synergy's generators according to a set of dispatch guidelines, many of which are not readily transferable to the PLEXOS model. To fully reflect the application of the guidelines would require an iterative modelling process which was impractical for this exercise. Instead, scheduling was conducted using the marginal costs rather than the dispatch guidelines except in a few specific instances where constraints were derived from them.

Generator output data shows some large thermal generators, such as Collie and Muja, are withdrawn from service but that these withdrawals are unrelated to outages. Model refinements allowed the model to better determine when large thermal generators were likely to be out-of-merit and should be decommitted.

Generators may offer generation at the minimum and maximum price caps. It is also within the rules for generators to offer generation at below its marginal cost. The model forecasts an increasing number of negatively priced events in the market. The model is calibrated on past behaviour which may not accurately predict future behaviour – particularly when such behaviour has substantial cost implications. Some bidding behaviour – such as withdrawing generation from the market or changing from participating in one market such as LFAS and moving into the balancing market at different times of day may also be subject to change.

Finally, while the ERA has wide access to information necessary to model the market, it does not hold every piece of information and some information held by the ERA cannot be used for every function the ERA must perform. Information on fuel supply contracts in Western Australia in the gas and coal markets are generally opaque. Fuel supplies may also be tied to the availability or demand for fuel in other markets such as to or from mining or industrial projects. It is not feasible to model the two markets (gas and electricity) in this process. Informal engagement with generators in preparing the input assumptions indicates there are some unspecified fuel supply constraints that may apply in practice that were not provided to the ERA and are not included in the modelling informing this paper.

Quality assurance processes

The ERA undertook quality assurance processes at different stages of preparing the model and reviewing the model outputs. These included:

- reviewing the model inputs
- verification of the model inputs
- back-casting
- reviewing model outputs
- sensitivity analysis.

Several scenarios were tested during the preparation of the model. These scenarios tested different aspects of the model, such as using different input costs, different configuration settings to ensure a proper understanding of the model, how it schedules generators and replicates market dynamics. This information can then be used to identify the best means to configure the model to ensure a reasonable representation of the WEM operations.

Model inputs relevant to individual generators were collected from market participants under the market rules.[64] This information was collated and compiled with other physical generator characteristics relevant to the modelling and provided to market participants for review.

Discussions were held with AEMO regarding the scheduling of ancillary services, generator scheduling, the reasonableness of aggregate model outputs and market dynamics. Discussions were also held with both Western Power and AEMO in preparing constraints to apply to generators connected under the generator interim access arrangement.

The model outputs was first compared to a historical period with known prices and demand characteristics (back-casting). Sources of variability such as outages and variable generator outputs were not modelled at this stage rather were fixed inputs used to minimise error in the back-casting model. The back-casting runs used actual outage data and variable generator output. This approach reduced potential sources of error and allowed refinement of inputs and model configuration to better reflect individual generators' bidding characteristics.

The forecast model outputs also looked at patterns of generator dispatch and pricing behaviour. Price duration curves for the different model iterations, capacity factors, commitment and decommitment patterns were compared with comparable past periods and dispatch trends. Where values were substantially higher or lower than expected, a deeper assessment was conducted on the scheduling decisions and refinements were made as necessary.

Sensitivity analysis was conducted around fuel prices with variables of +/-$1/GJ from an anticipated opportunity gas cost. Sensitivity analysis was also conducted on different PV penetration rates.

[64] Wholesale Electricity Market Rules, 1 February 2021, rule 2.16.

Ancillary service cost allocation

Generators provide many services in an electricity market including ancillary services. It is not uncommon for generators to be providing multiple services within a market including into the balancing market, load following ancillary services and contingency mitigation ancillary services like spinning reserve and load rejection reserve.

Most generators when constrained on for a particular need – such as to maintain system security – would be compensated through a constrained-on payment. Synergy however bids as a portfolio. Capacity can be cleared to run but is not linked to any particular generator. Consequently, capacity from low-cost generators like Collie or the Muja power stations can be substituted for capacity from relatively high-cost generators like the Pinjar power station within the portfolio in a manner that would not be compensated by constrained-on payments through market settlement. This section steps out how different elements of the operational costs (such as the minimum generation quantity and quantity dedicated to downwards LFAS) are allocated across the various services in the electricity market and broadly reflects the following priorities:

1. Balancing market
2. Load following ancillary services market
3. Load rejection reserve and spinning reserve

The SWIS ready reserve is modelled as a contingency such that sufficient fast-start generators are available to meet the requirements under the market rules.[65] No specific cost modelling is considered with this service.

Balancing market

The balancing market provides the base service and notional costs allocated to ancillary services only accrue where the balancing market revenue is insufficient to cover the cost. In these situations, Synergy recovers the cost of providing other ancillary services through other market mechanisms. How costs are allocated between the different services is illustrated in figures A 3 to A 17.

Load Following Ancillary Services

LFAS participation and cost should be independent of the provision of spinning reserve ancillary services to reflect the discrete LFAS market and ensure consistency of treatment and opportunity with non-Synergy generators. The market rules require generators to bid their minimum generation quantities. The minimum generation quantities required to be bid at the floor when a generator participates in the LFAS market accrues to LFAS for the purposes of cost allocation even where other ancillary services are provided. This ensures consistent risk exposure for Synergy and other LFAS service providers.

Spinning Reserve and Load Rejection Reserve

The costs accruing to spinning reserve and or load rejection reserve will depend on the market circumstances at the time. The following subsections step out different combinations of

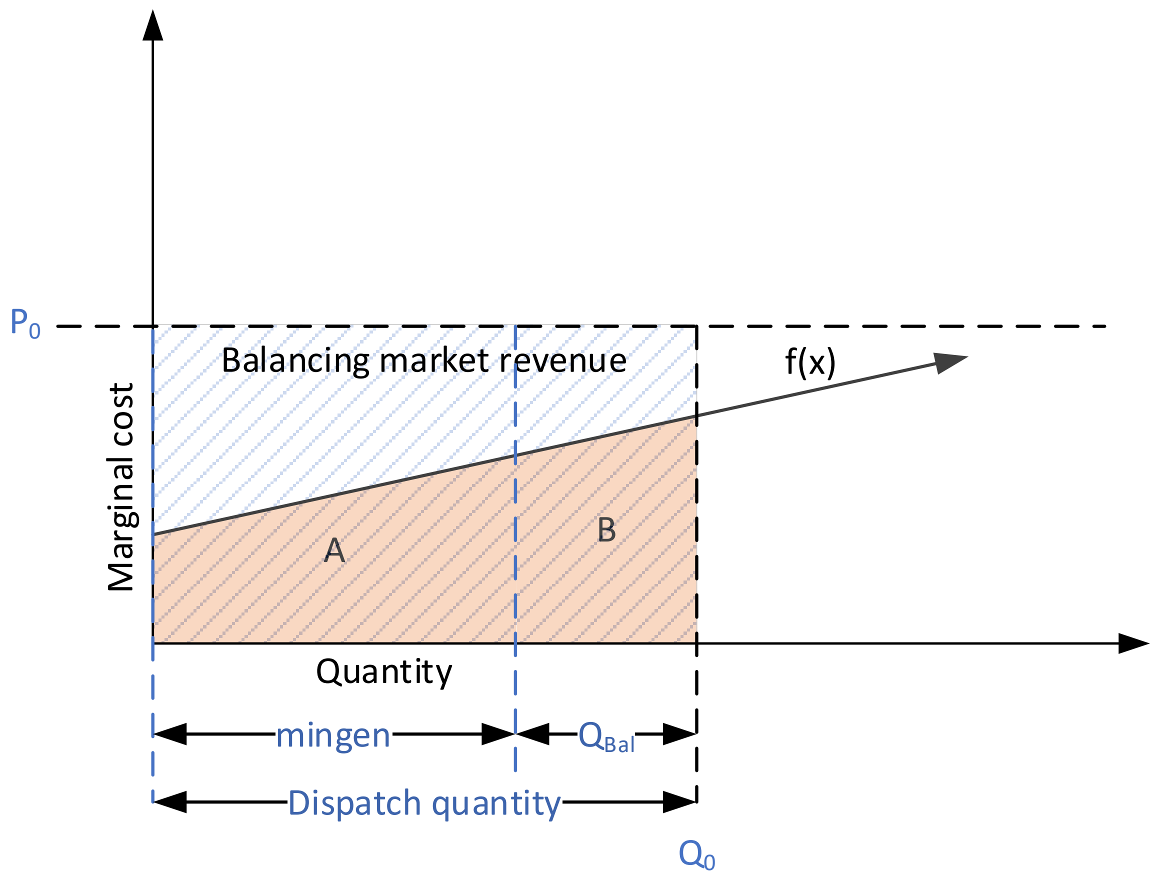
[65] Wholesale Electricity Market Rules, 1 February 2021, rule3.18.11.A.

ancillary services and explain the rationale for accruing costs to different ancillary services when the generator is within the economic merit order or out-of-merit

The diagrams follow a similar format with quantity on the x axis and price on the y axis. The line f(x) shows the marginal cost curve for the generator in question and the area under the curve shows the costs incurred by the generator for its output.

In this example, the area marked 'A' is the are bound by the minimum stable generation level of the generator. The area marked 'B' is dispatch above the minimum – here into the balancing market. Balancing market revenue for this generator is the area bound by the balancing price and the dispatched quantity (P_0 x Q_0) shown by the blue hatched area. Solid blocks of pale orange denoted by capital letters indicate areas of cost or foregone revenue accruing to different market mechanisms. Hatched areas in pale orange are avoided costs.

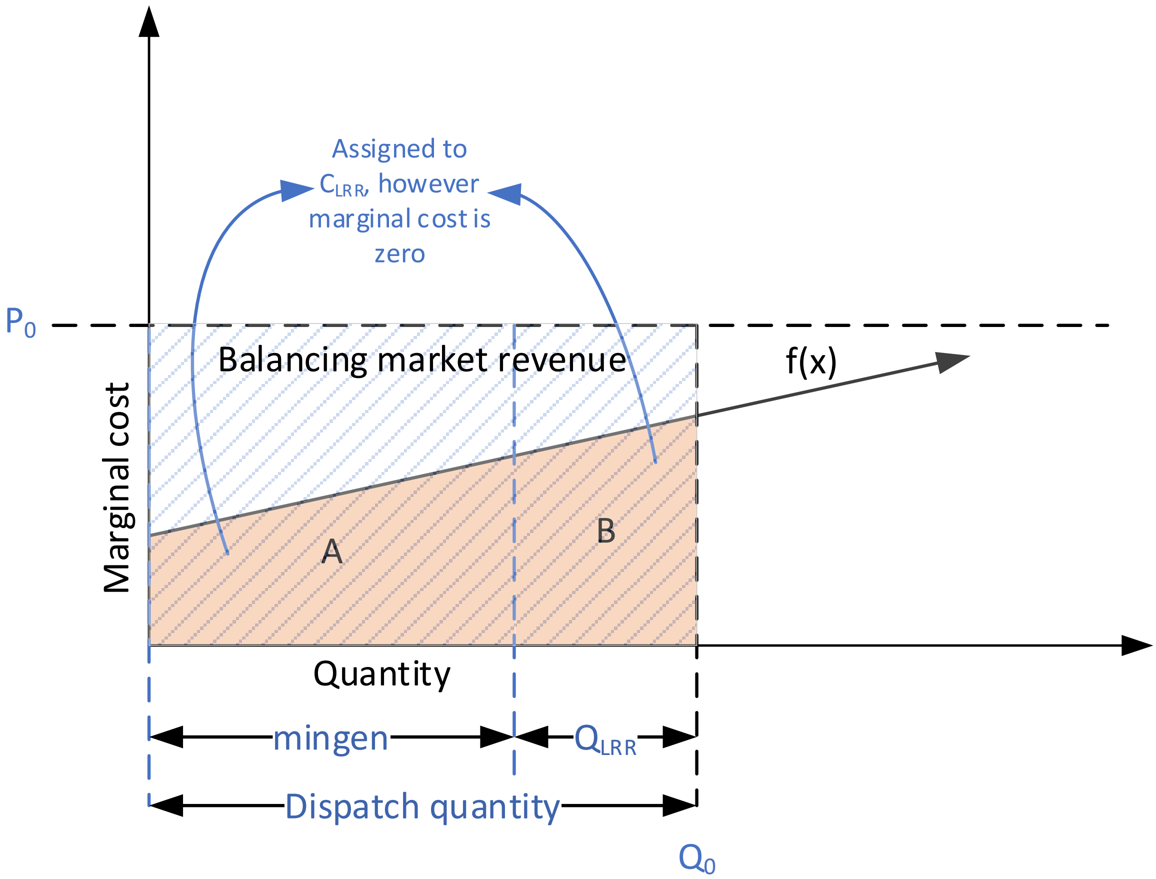
Figure A 3 Dispatch conceptual diagram



A generator providing Load Rejection Reserve only

Where a generator is providing load rejection reserve and it's marginal cost of production is less than the balancing price it is considered to be 'in-merit'. Figure A 4 shows the different costs incurred by the generator.

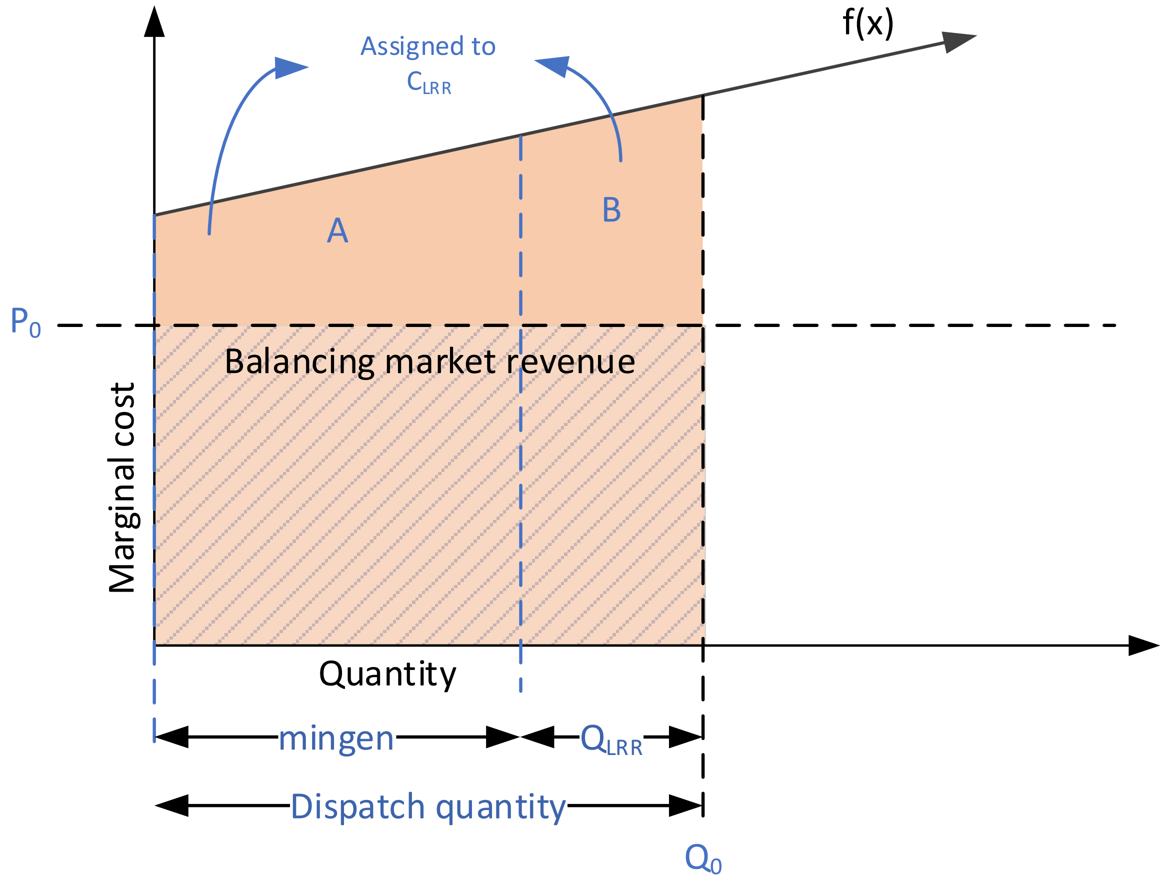
Figure A 4: Generator providing load rejection reserve when in merit



Such a generator would earn revenue from the balancing market for its full dispatch. No incremental costs are assumed to be incurred to be capable of reducing its output. Consequently, the generator would require no additional compensation to provide load rejection reserve because the costs incurred (area 'A' and 'B') are less than the revenue it would receive.

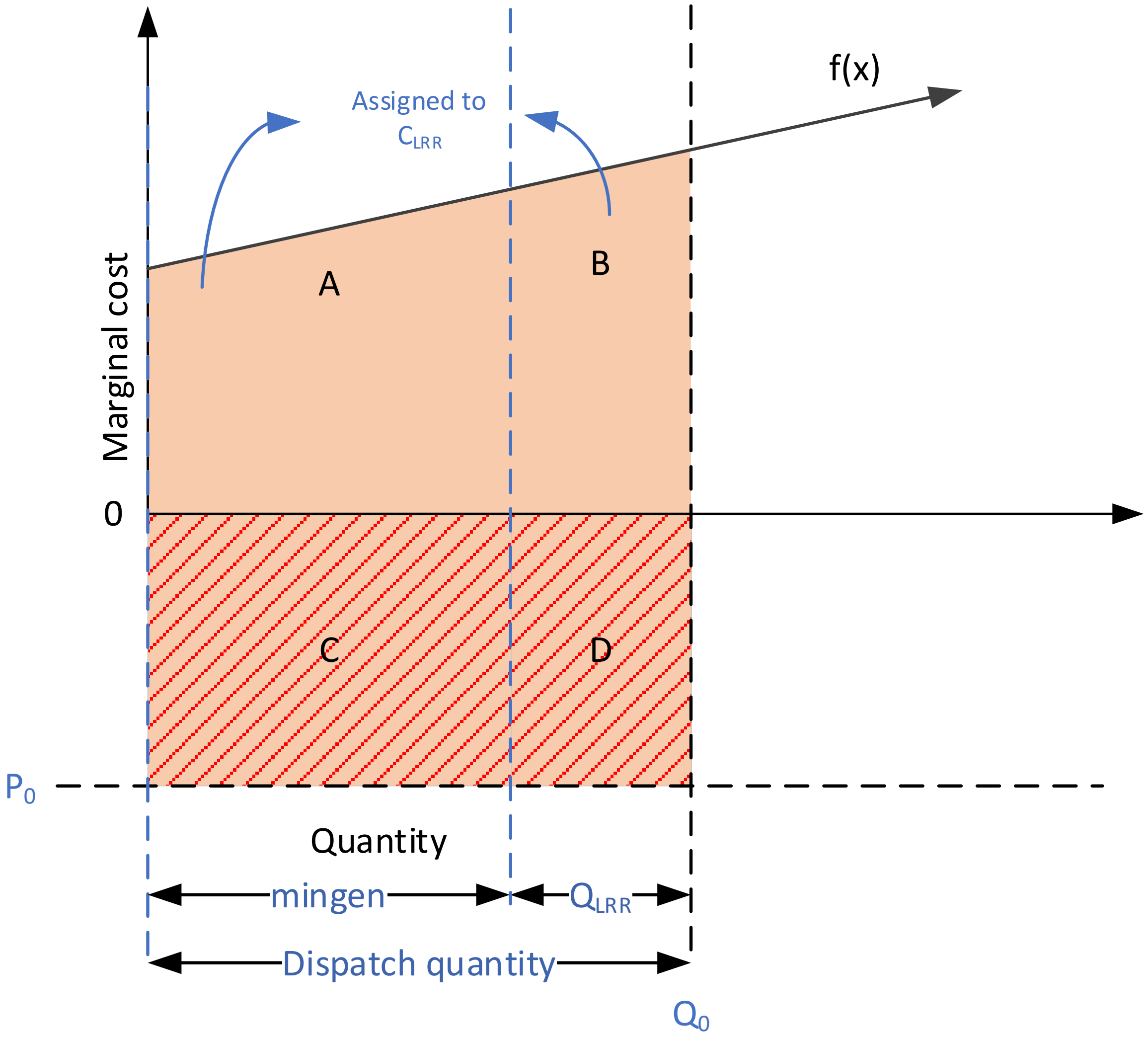
However, when that same generator's marginal cost exceeds the balancing price (such as in Figure A 5), it is considered 'out-of-merit'. Balancing market will provide some compensation up to the balancing market price. However the generator incurs costs that exceed this. In this situation the generator would need to be compensated for the difference between the balancing market review and the operational costs for its minimum generation (mingen or area 'A') and the quantity of load rejection reserve provided (Q_{LRR}), or area 'B'.

Figure A 5: Generator providing load rejection reserve when out-of-merit



Where prices clear below zero, the gap between the balancing market price, and the marginal cost of the generator is larger, and also compensates the generator for the cost of dispatch into a negatively priced market.

Figure A 6: Generator providing load rejection reserve when out-of-merit and prices are negative

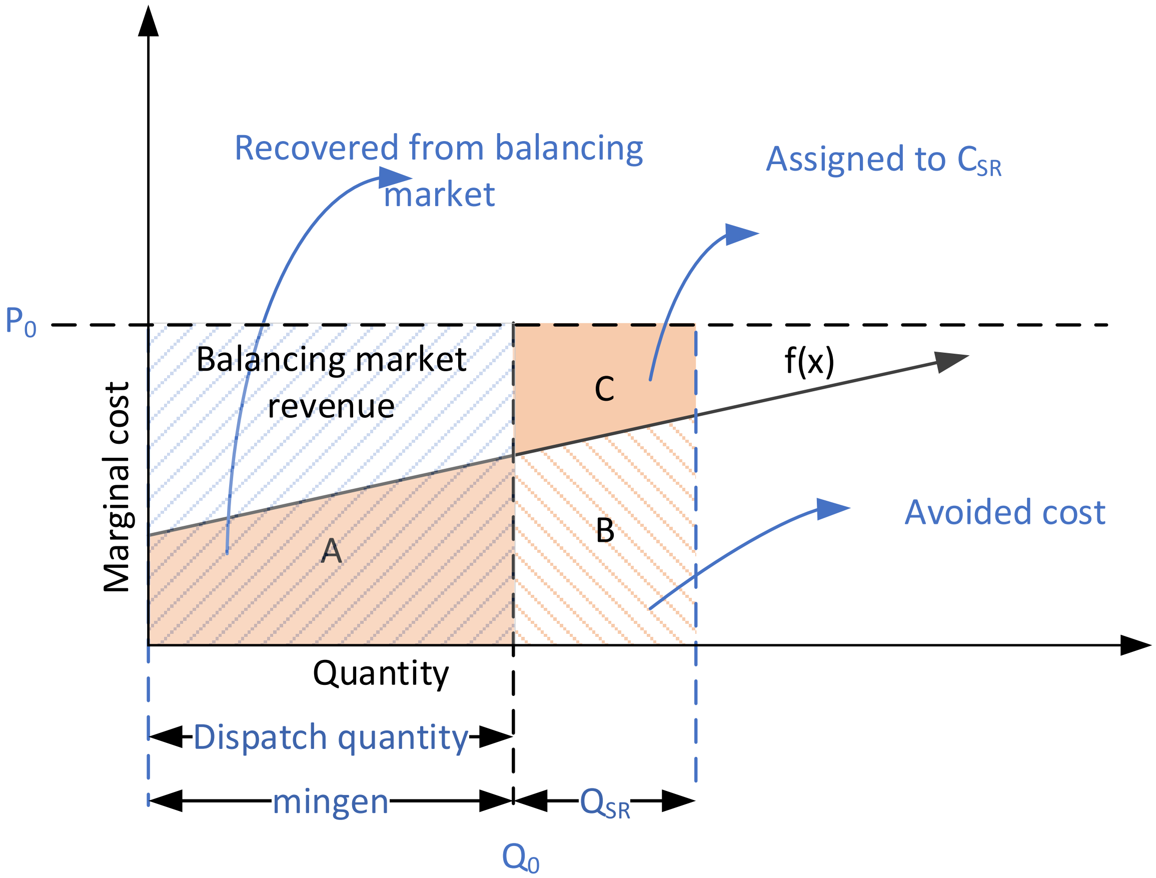


When prices are negative, areas 'C' and 'D' are paid by a generator to remain in service. These also need to be compensated for in addition to areas 'A' and 'B' – the full marginal cost of the generators dispatching.

A generator providing spinning reserve

Figure A 7 below shows a generator providing spinning reserve only. The generator has some of its in merit capacity withheld to provide spinning reserve (Q_{SR}). As with the previous example, the hatched area shows balancing market revenue and the tan areas the area under the marginal cost curve f(x).

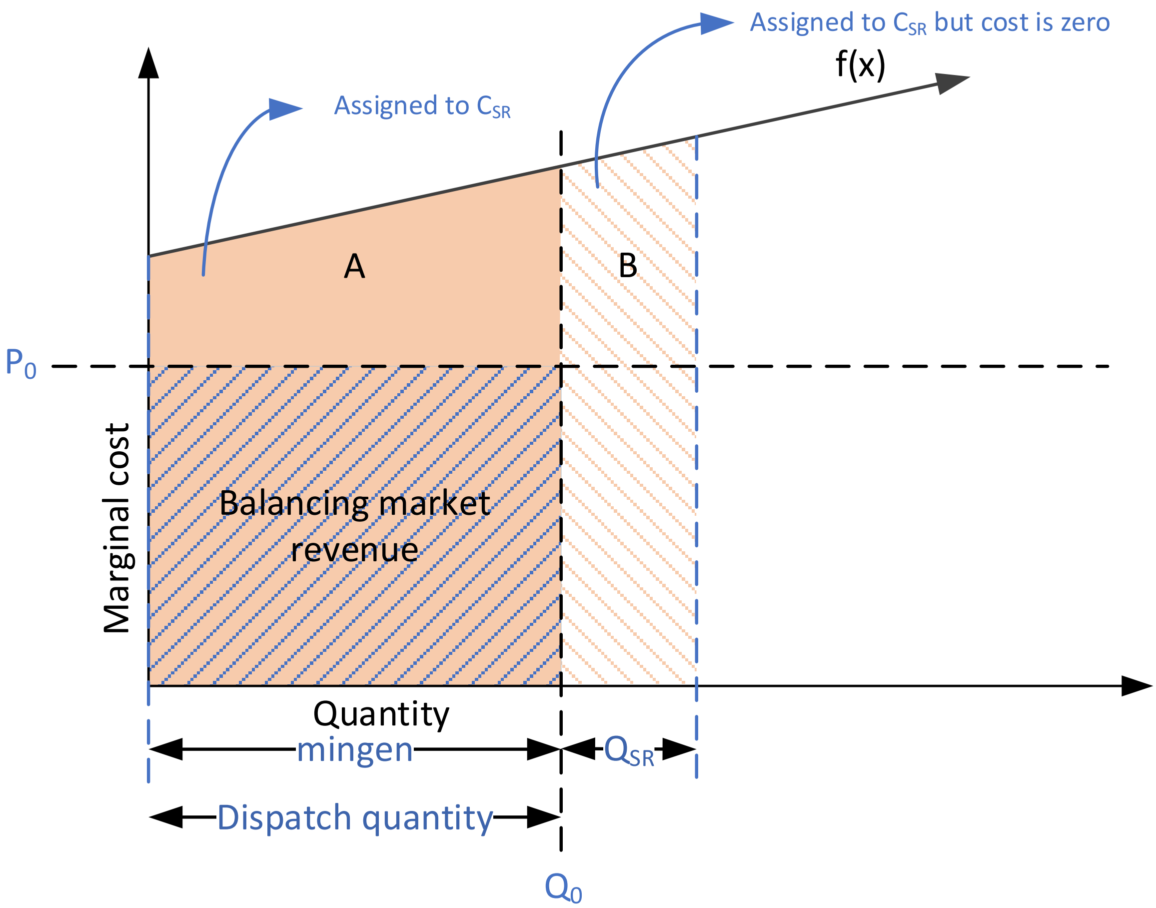
Figure A 7: A generator providing spinnign reserve only when in merit



Here, area ‘A’ is entirely within the region compensated by the balancing market and requires no additional compensation. Area ‘B’ is the cost avoided that would have been covered by the revenue from the balancing market – this does not require compensation. Area ‘C’ however is foregone revenue that would have been earned had the generator been able to dispatch within merit. This represents the opportunity cost of providing spinning reserve. This cost should be assigned to the availability cost for spinning reserve.

Where a generator is providing spinning reserve and it is scheduled to run out-of-merit (as shown in Figure A 8), area ‘A’ is not entirely covered by balancing market revenue. This area above the balancing price requires compensation. Area ‘B’ however, is an avoided cost and requires no compensation. The generator avoids further out-of-merit operational costs by not dispatching this quantity. In this example, the generator only needs to be compensated for the operating cost difference between the balancing price and its out-of-merit dispatch quantity – usually to its minimum generation.

Figure A 8: A generator providing spinnign reserve only when out-of-merit



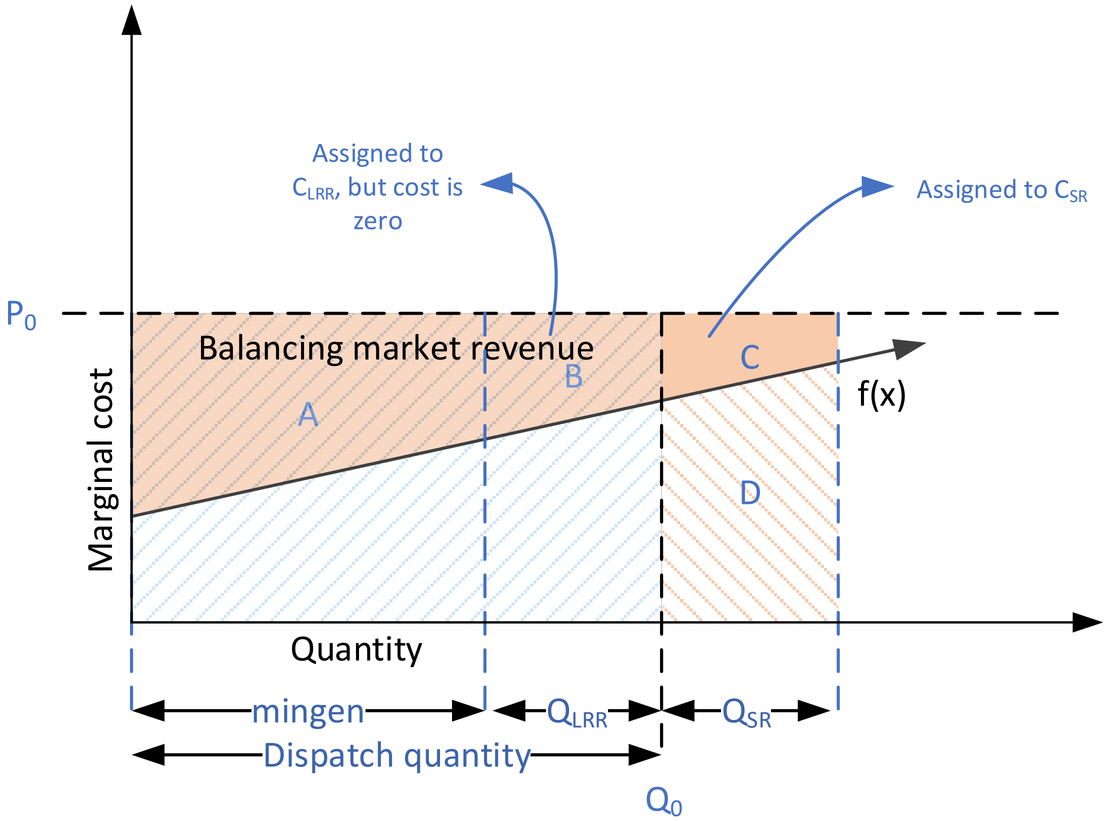
Where a generator is providing spinning reserve out-of-merit, and generation is withheld, there is no opportunity cost of providing spinning reserve. It avoids a cost that exceeds the revenue it would have received had it been dispatched. Area 'B' does not need to be compensated – only area 'A'.

A generator providing Load Rejection Reserve and Spinning Reserve Service

Where a generator is providing both spinning reserve and load rejection reserve, costs may be incurred for one or other service or both depending on whether the generator is in or out-of-merit.

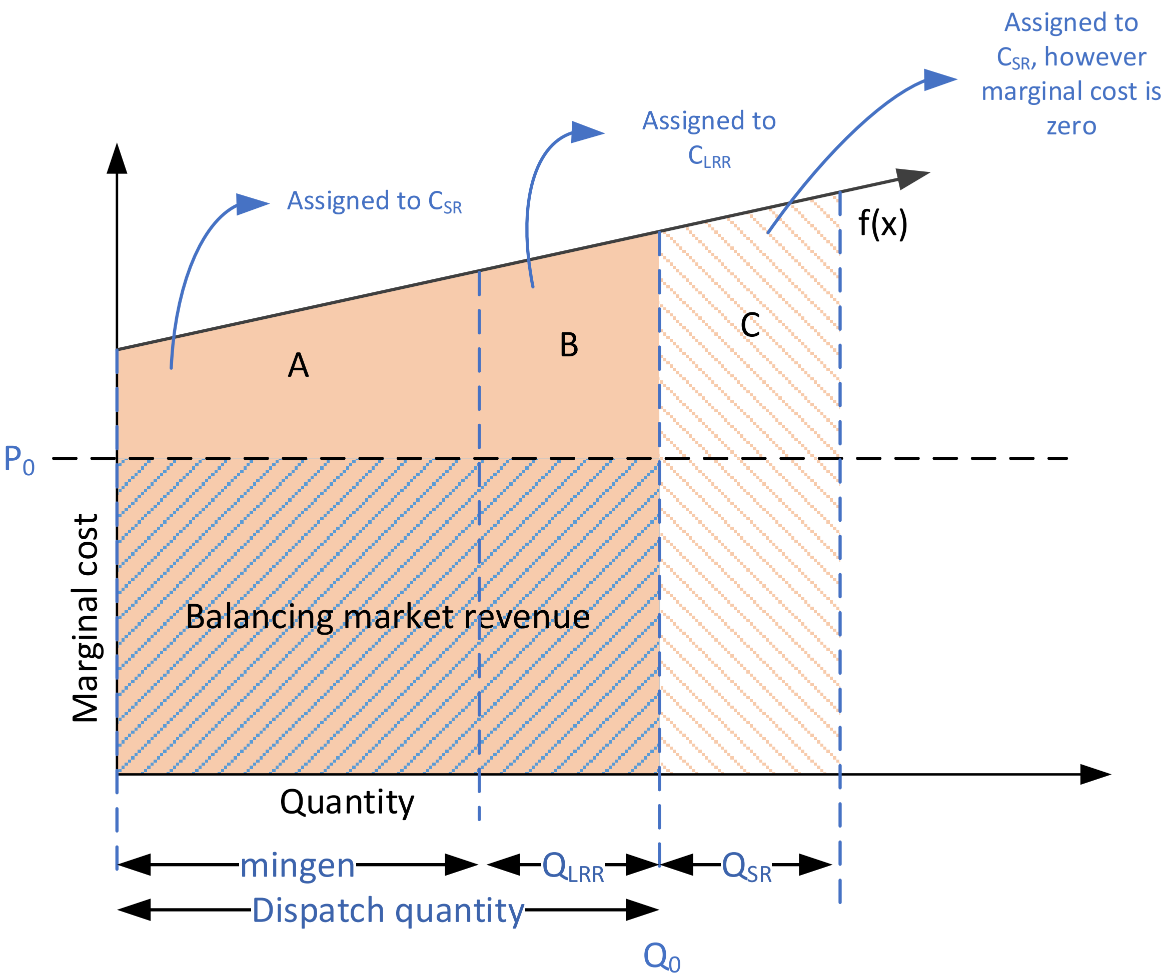
For a generator in merit (shown in Figure A 9), the costs to run up to the minimum generation quantity are recovered through the balancing market and no compensation is required. As with the example for LRR only, the cost for being available to reduce output when in merit is fully recovered through the balancing market and again, no additional revenue is required to keep a generator whole to this point. However, for the spinning reserve provided (Q_{SR}) the generator could have generated more in merit. There is an opportunity cost in terms of foregone revenue indicated by area 'C' which would accrue to the availability cost for providing spinning reserve. Area 'D' is avoided cost that requires no compensation.

Figure A 9: Generator providing spinning reserve and load rejection reserve in merit



For a generator operating out-of-merit providing both spinning reserve and load rejection reserve (shown in Figure A 10), a different set of costs accrue to the operation. There is a cost of generating to the minimum generation quantity (Area 'A'), this is applied to the cost to provide spinning reserve. Area 'B' is operation out-of-merit for the purpose of providing spinning reserve. Area 'C' is the capacity dedicated to spinning reserve and is an avoided cost and has a marginal cost of zero.

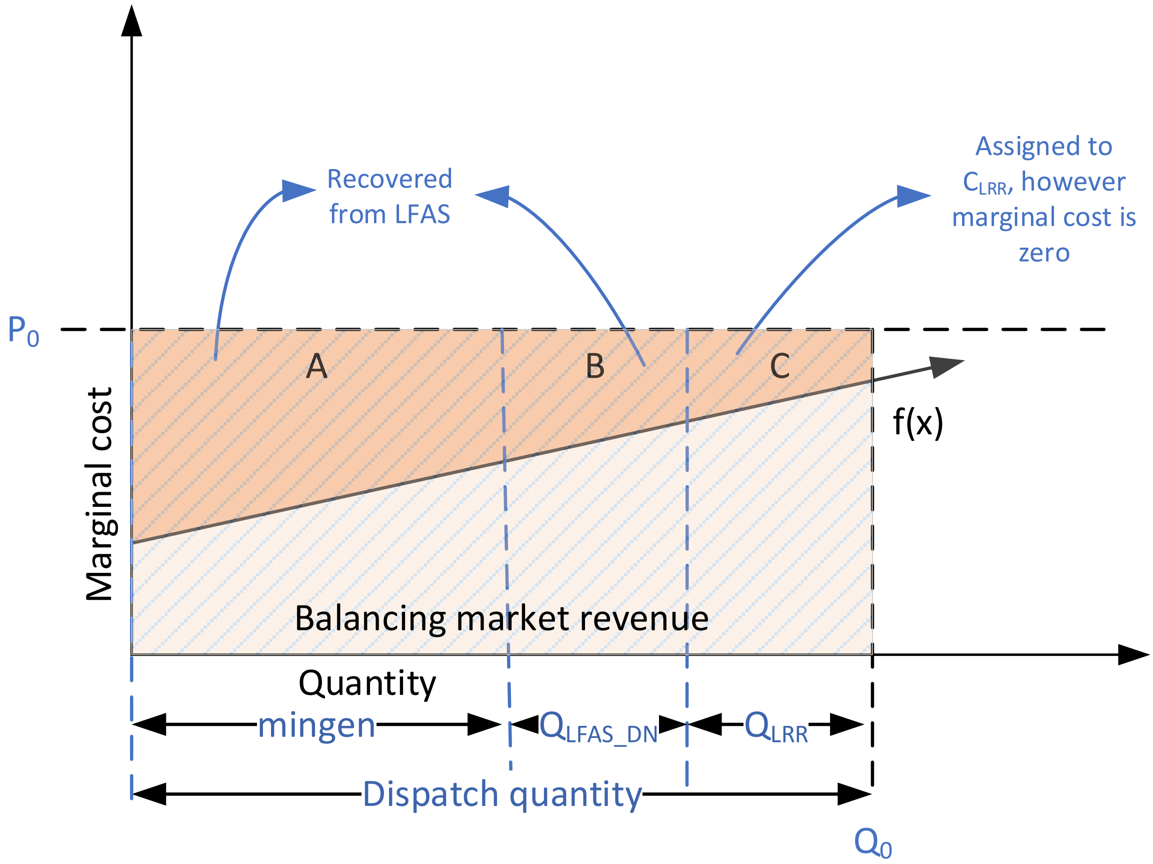
Figure A 10: Generator providing spinning reserve and load rejection reserve out-of-merit



A generator providing load rejection reserve and load following ancillary service

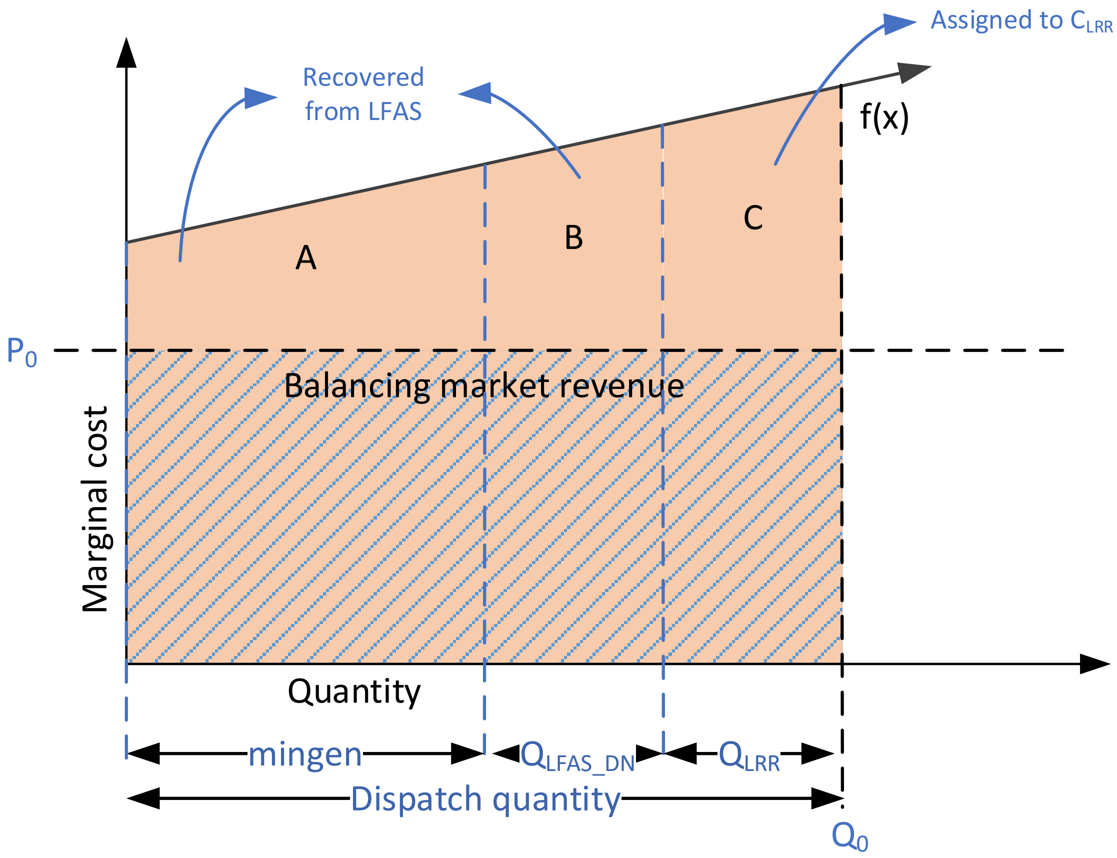
Where the generator is also providing LFAS services, depending on whether the generator's marginal cost is above or below depends on whether a cost is incurred to provide each service. Where a generator is providing these services and is in merit (shown in Figure A 11), area 'A' and the operational costs to the minimum generation are fully recovered from the balancing market and notionally assigned to LFAS participation. Area 'B' is LFAS market participation and the costs are recovered from the LFAS market. Area 'C' is assigned to the cost of load rejection reserve, however, the costs are fully recovered from the balancing market. In this example, no additional incremental costs are accrued to any service that it can't recover through normal market mechanisms.

Figure A 11: A generator providing LFAS and load rejection reserve operating in merit



Out-of-merit however, (shown in Figure A 12) the operational costs for being constrained on for the region up to minimum generation (area 'A') and that assigned to the LFAS service (area 'B') are assigned to the LFAS market. Area 'C' is constrained on to provide load rejection reserve and accrues to the load rejection reserve availability cost.

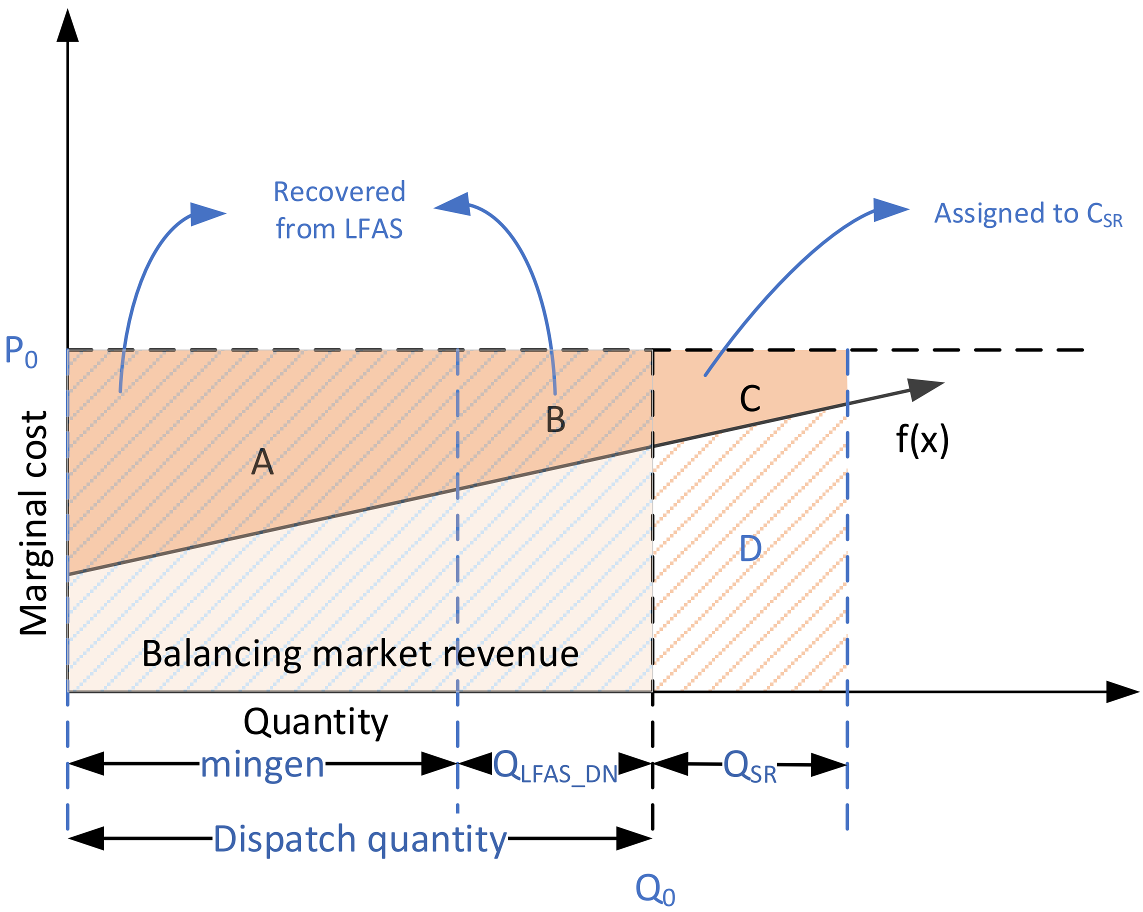
Figure A 12: A generator providing LFAS and load rejection reserve operating out-of-merit



A generator providing spinning reserve and load following ancillary service

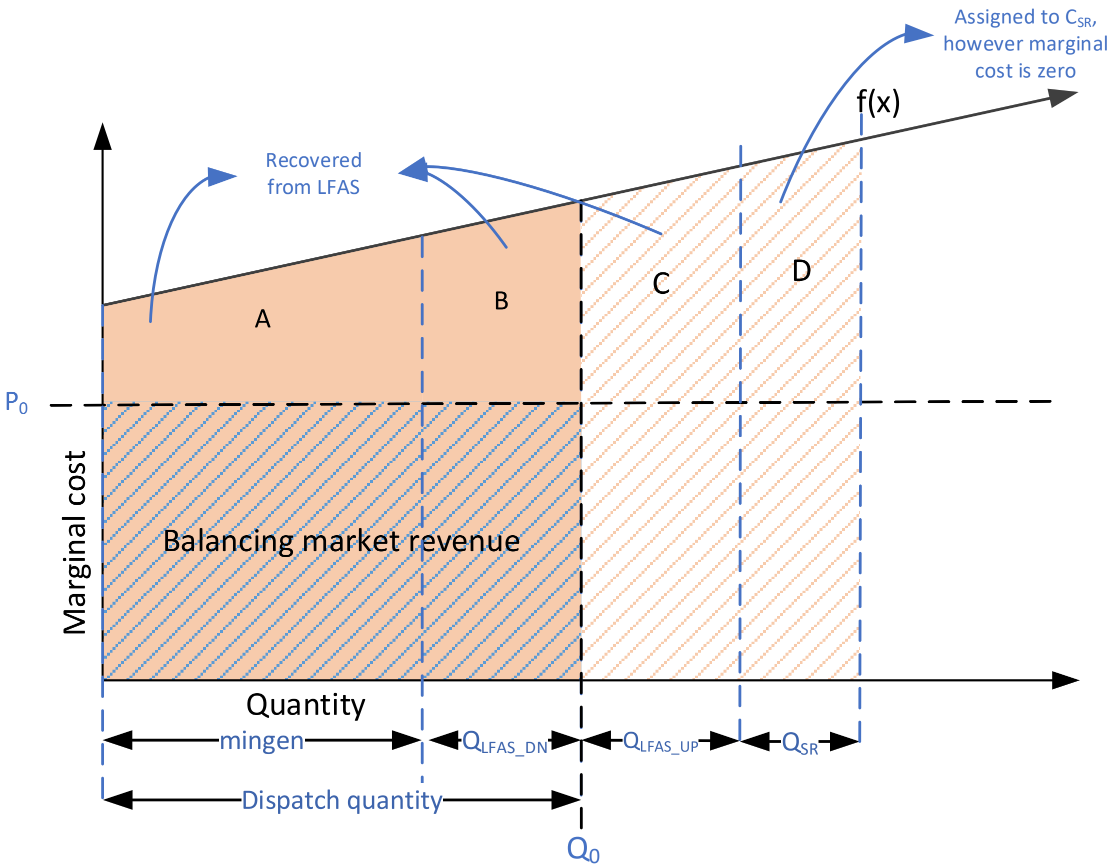
Where a generator is providing spinning reserve and load following ancillary service in merit (shown in Figure A 13), the area up to minimum generation is fuller recovered through the balancing market and is assigned to the cost of providing LFAS. Area 'B' is recovered through the LFAS market and is similarly covered by the balancing market. Area 'C' reflects foregone revenue for in merit sales and is the opportunity cost of providing spinning reserve. This cost would accrue to the spinning reserve availability cost. The avoided operational costs are indicated by area 'D' and this requires no compensation.

Figure A 13: A generator providing spinning reserve and load following ancillary service operating in merit



When operating out-of-merit and providing spinning reserve and load following ancillary service, the minimum generation quantity is assigned to the cost of providing load following ancillary service. The balancing market revenue is insufficient to cover this cost. This cost and that of area ‘B’ are assumed to be recovered through the LFAS market. Area C is an avoided cost linked to the LFAS market. Area ‘D’ is an avoided cost that would accrue to the availability cost of spinning reserve. However, the marginal cost to be able to increase output is zero.

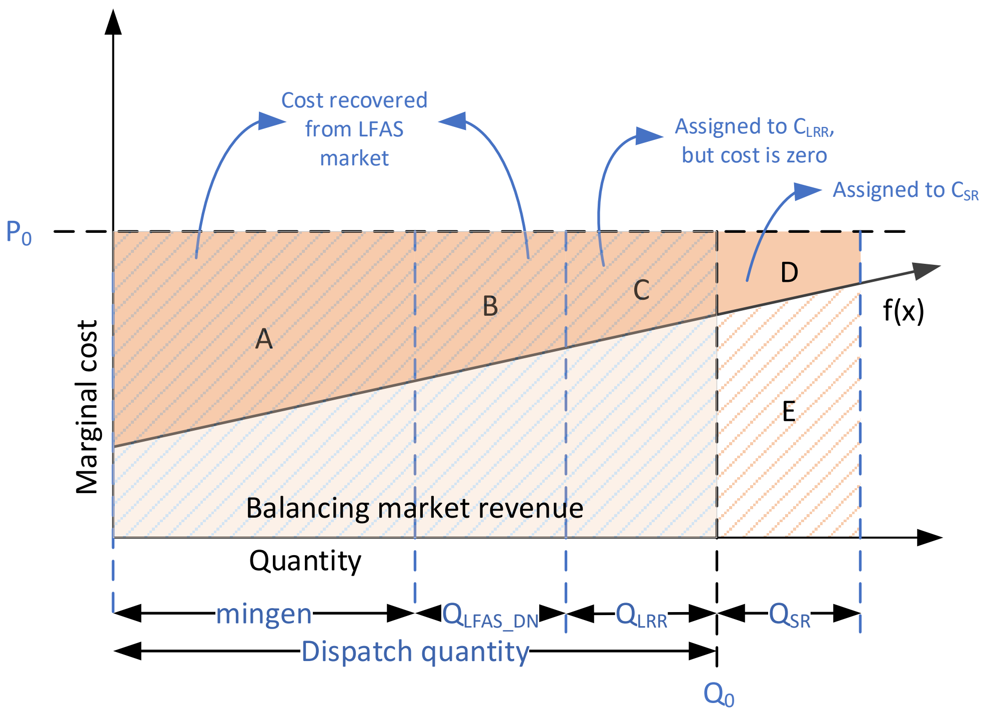
Figure A 14: A generator providing spinning reserve and load following ancillary service operating out-of-merit



A generator providing spinning reserve, load rejection reserve and load following ancillary service

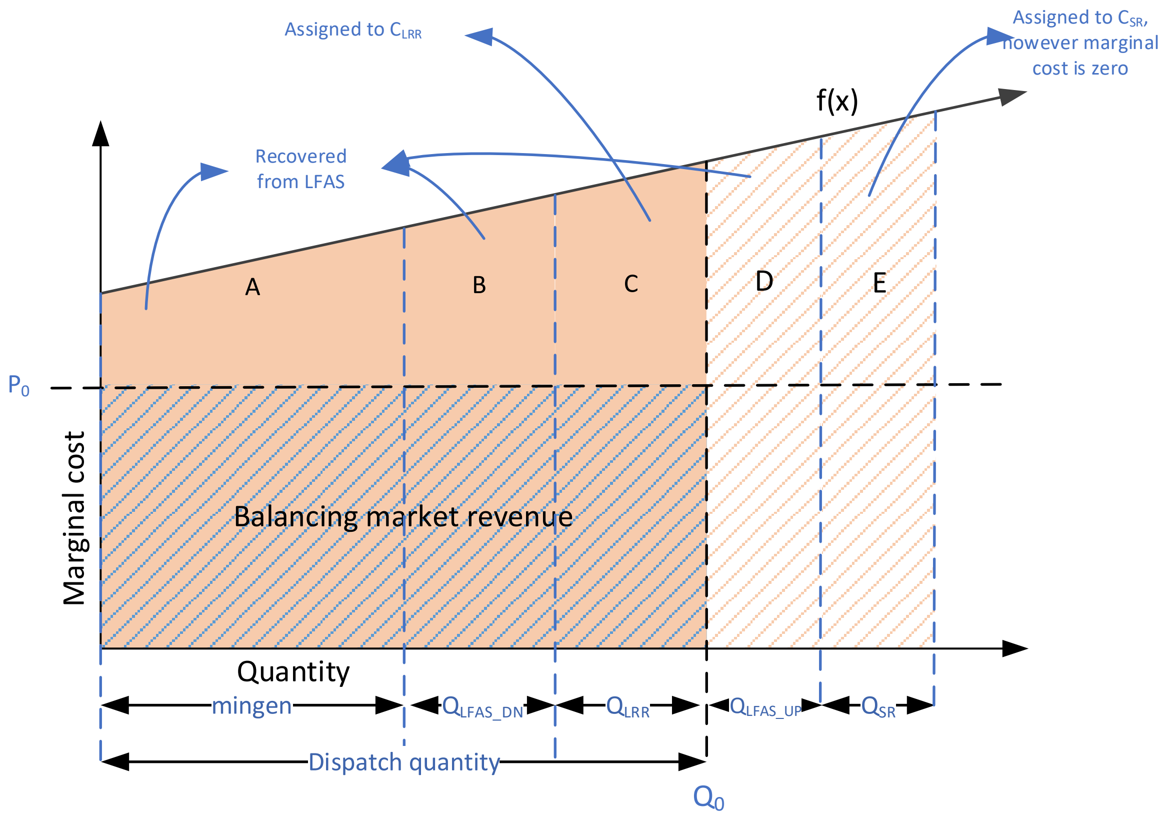
The costs associated a generator providing LFAS, load rejection reserve and spinning reserve are shown in Figure A 15 below. The cost to minimum generation shown by area 'A' and the cost to provide load following ancillary service down shown by area 'B' are assumed to be recoverable from the balancing and LFAS markets. Area 'C' is the load rejection reserve provision. The cost for this service is fully recovered from the balancing market. Areas 'D' and 'E' are linked to spinning reserve. Area 'D' is foregone revenue as the marginal cost of the generator is less than the balancing market price and would accrue to the spinning reserve availability cost. Area 'E' is avoided cost and requires no compensation.

Figure A 15: A generator providing LFAS, load rejection reserve and spinning reserve operating in merit



If the balancing market price was to fall below the marginal production cost of the generator, (Figure A 16) area 'A' which is for LFAS provision and with areas 'B' and 'D' the cost would be recovered through the LFAS market. Area 'C' is the cost of the generator being constrained on to provide load rejection reserve and the cost difference between what it would receive from the balancing market and the cost of production. The output withheld for spinning reserve (area 'E') is an avoided cost and requires no additional revenue to keep the generator whole and the marginal cost is zero.

Figure A 16: A generator providing LFAS, load rejection reserve and spinning reserve operating out-of-merit



Appendix 2 Summary of stakeholder feedback

The ERA received five submissions in response to the margin values and cost_LR 2021/22 issues paper and subsequent addendum to the issues paper. All submissions are available on the ERA's website. A short summary of each submission is provided below.

AEMO[66]

At the ERA's request AEMO provided its submission early in the consultation period as it provided additional information on the higher spinning reserve requirement announced in January 2021.

AEMO's submission provided preliminary analysis to demonstrate that a proportion of rooftop solar systems disconnected after transmission line trips. AEMO had set the increased spinning reserve requirement equivalent to mitigate the effect of 10 per cent of solar systems connecting. However, AEMO noted that its analysis would continue and the quantity of additional spinning reserve needed may change.

AEMO's submission noted the importance of correctly allocating costs to spinning reserve and load rejection reserve because costs were recovered from generators and retailers respectively. A possible approach to cost allocation was outlined in the submission.

Bluewaters Power and NewGen Kwinana Power[67]

The ERA received identical submissions from both generators. The submission confirmed that market dynamics were displacing thermal generation, wholesale electricity pricing had become more volatile and there was an increasing incidence of negative priced intervals. The submission acknowledged that ancillary service prices would rise until technology such as storage was present to smooth the increasing variability in demand and supply. Bluewaters and NewGen Kwinana were concerned that the cost recovery of ancillary services was skewed towards scheduled generators. Distributed PV was contributing to the quantity of spinning reserve required in the market but did not pay for the spinning reserve service. The submission suggested AEMO could increase LFAS to cover the solar contingency would lead to a more equitable market outcome than increasing the spinning reserve requirement.

The Bluewaters and NewGen Kwinana submissions also noted that balancing price forecasts had not identified -$1000 pricing events and that the minimum STEM price was likely to change.[68] This may be inconsistent with the negative pricing events shown in the ERA's forecast costs for spinning reserve and load rejection reserve.

The submission recommended rolling over the parameters approved for 2020/21 and recognised that the current mechanism of determining margin values was no longer fit-for-purpose.

Perth Energy[69]

The submission questioned the ERA's modelling approach, including the regulator's decision

66 AEMO, 2021, *Submission on issues paper: Ancillary service costs – spinning reserve, load rejection reserve and system restart (Margin Values Cost_LR) for 2021/22*, (online)

67 Bluewaters Power and NewGen Kwinana Power, 2021, *Response to issues paper – Ancillary Service Costs – Spinning Reserve, Load Rejection Reserve and System Restart (Margin Values Cost_LR) for 2021/22*, (online)

68 The ERA is currently reviewing the Minimum STEM price (online).

69 Perth Energy, 2021, *Determination of margin values and cost_LR parameters for 2021/22*, (online)

to purchase market modelling software, and recommended AEMO's proposed parameters for 2021/22. Perth Energy suggested that AEMO was the authority on market dynamics and was better placed to estimate margin values and Cost_LR.[70] Perth Energy did not agree that the market had changed sufficiently within the previous 12 months to justify the change in spinning reserve and load rejection reserve costs indicated in the ERA's forecasts. Instead, Perth Energy suggested increased ancillary service costs came from an error in the ERA's modelling. The submission stated that forecast balancing prices were too low and that should actual balancing prices be higher than forecast, Synergy would receive a windfall gain. Perth Energy suggested the ERA provide a detailed explanation for each of the drivers on the increase in ancillary service costs along with analysis on the sensitivity of each parameter to those drivers, consistent with stakeholders' expectations of AEMO's modelling in previous years.[71] Perth Energy recommended the ERA approves AEMO's proposed values for system restart and load rejection reserve.

For system restart services, Perth Energy suggested the ERA's involvement in approving system restart cost resulted in inequitable outcomes for the market.[72] Where the ERA approved system restart costs below the contracted cost then the balance is subtracted from load rejection reserve costs and there may be insufficient funds to cover load rejection reserve costs when they occur. Perth Energy acknowledged that load rejection reserve and system restart costs will be separated and recovered through separate mechanisms in the new essential service market to be introduced in October 2022.

Synergy[73]

Synergy's submission supported the adoption of ERA determined spinning reserve and load rejection reserve values. This was despite Synergy having pointed out what it considered were modelling deficiencies such as an inappropriate gas price assumption, how the balancing portfolio had been modelled and that the ERA had used a co-optimised market simulation model.[74] Synergy acknowledged that AEMO's proposal did not take into account recent market dynamics or the increased spinning reserve requirement.

Synergy commented that although upwards LFAS is a substitute for spinning reserve, in reality generator dispatch needs to account for consumed LFAS before any remaining LFAS can be used to provide spinning reserve. Given this point more generation may need to be dispatched in real time, than was considered efficient with the benefit of hindsight. A modelled spinning reserve cost would not account for this observation.

Synergy suggested that consultation be continued for the determination of margin values and Cost_LR for 2022/23 to avoid future under or over-compensation of ancillary services.

70 After releasing the notice on a higher spinning reserve quantity in January 2021, the ERA asked AEMO if it would submit revised margin values and Cost_LR parameter and AEMO declined.

71 This sensitivity analysis is provided in section 4.2 of this report.

72 Perth Energy provides system restart services in the WEM.

73 Synergy, 2021, *Ancillary service costs – spinning reserve, load rejection reserve and system restart (Margin Values Cost_LR) for 2021/22*, (online)

74 The gas price assumption Synergy referred to was not the one the ERA used in its modelling, there is limited information available on how the balancing portfolio is managed and AEMO does not record this information and most market simulation models assume co-optimised energy and ancillary service dispatch.

Appendix 3 List of tables

Appendix 4 List of Figures