Ancillary services parameter review 2019 final report

PUBLIC VERSION

Australian Energy Market Operator

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Ernst & Young (we or EY) has been engaged by the Australian Energy Market Operator (you, AEMO or the Client) to provide electricity market modelling services to assist AEMO in calculating ancillary service parameters in accordance with the Western Australian Wholesale Electricity Market Rules (the Services), in accordance with our Assignment commencing 15 July 2019, under the Master Services Consultancy Agreement entered into by AEMO and EY commencing 28 November 2018.

The enclosed report (the Report) provides an overview of the modelling methodology and assumptions to be used in delivering the Services. A simulation model will form the basis for the outputs produced and either has been, or will be, agreed with AEMO, following the end of a public consultation process and after consideration of submissions received.

The Report should be read in its entirety including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. The Report has been prepared based on information current as of 29 November 2019, and which has been provided by the Client or other stakeholders, or which is available publicly. Since this date, material events may have occurred that are not reflected in the Report.

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1. Introduction

EY has been engaged by the Australian Energy Market Operator (AEMO) to provide electricity market modelling services to assist AEMO in calculating ancillary service (AS) parameters for the Wholesale Electricity Market (WEM) in Western Australia, in accordance with the Wholesale Electricity Market Rules (WEM Rules).

EY's modelling is related to the provision of the following AS:

- Spinning reserve service (SRAS) for the financial year 2020-21
- Load rejection reserve service (LRR) for the financial year 2020-21.

The above AS are used by AEMO to maintain security of the South West Interconnected System (SWIS) in Western Australia for contingency events involving the loss of generation or demand.

AEMO is required to determine, procure, schedule and dispatch facilities to meet the SRAS and LRR requirement in accordance with the WEM Rules.

SRAS and LRR are not subject to a competitive centralised market. AEMO may enter into an AS contract with a market participant (MP) for the provision of SRAS or LRR in accordance with the WEM Rules. In the case of SRAS, AEMO may enter into an AS contract with a non-market participant who is registered as an ancillary service provider under the WEM Rules. Synergy is the default provider of SRAS and LRR under the WEM Rules. Synergy is required to make its capacity to provide AS from its facilities available to AEMO to a standard sufficient to enable AEMO to meet its obligations in accordance with the WEM Rules.

Remuneration to Synergy for the provision of SRAS is determined by the Economic Regulation Authority of Western Australia (ERA) using an administered mechanism in accordance with the WEM Rules. The administrative nature of this remuneration mechanism requires AEMO to propose the following parameters relating to the SRAS, and the ERA to make a determination:

- The proposed Margin_Peak and Margin_Off-Peak values (Margin Values) for the purpose of clauses 3.13.3A(a)(i) and 3.13.3A(a)(ii) of the WEM Rules

In relation to the Margin Values, clause 3.13.3A of the WEM Rules requires:

- AEMO to submit proposed Margin Values for the 2020-21 financial year to the ERA by 30 November 2019
- the ERA to determine the Margin Values for the 2020-21 financial year by 31 March 2020, after undertaking a public consultation process.

The SR_Capacity_Peak and SR_Capacity_Off-peak values (i.e. capacity values for the SRAS) assumed in forming the Margin Values must be used for the purpose of settlement in clauses 3.22.1(e) and 3.22.1(f) of the WEM Rules.

Remuneration to Synergy for the provision of LRR is determined using an administered mechanism in accordance with the WEM Rules that requires ERA approval. The administrative nature of this remuneration mechanism requires AEMO to propose the following parameters for a three-year period relating to the LRR, and the ERA to make a determination:

- The proposed 'L' parameter of Cost_LR, representing the LRR cost for the purposes of clause 3.13.3B(a) of the WEM Rules.

In 2018 AEMO submitted a proposal for Cost_LR for the review period 2019-20 to 2021-22, however the ERA did not approve AEMO's proposal, and instead determined alternative values for Cost_LR. In the ERA's determination paper for the Margin Values 2019-20 and Cost_LR 2019-20 to

2021-22 (ERA 2019 Determination),[1] a recommendation was made to AEMO to review and resubmit revised proposals for 2020-21 and 2021-22. We understand that AEMO has since determined that LRR costs may be materially different than the costs determined under clause 3.13.3B and will be submitting a revised value for the 'L' parameter of Cost_LR for the 2020-21 year, in accordance with clause 3.13.3C(a) of the WEM Rules.

In relation to the Cost_LR parameter, clause 3.13.3C of the WEM Rules specifies:

- For any year within a review period if AEMO determines Cost_LR for the following financial year (FY) to be materially different than the costs provided under clause 3.13.3B of the WEM Rules, AEMO must submit an updated proposal for the Cost_LR values to the ERA by 30 November of the year before the start of the relevant financial year
- The ERA must determine the Cost_LR values for that financial year.

Once determined by the ERA, these parameters are used by AEMO in settlements to calculate payments to Synergy to recover its expected costs of providing SRAS and LRR. Historically, these values have also been considered in the payments to non-Synergy SRAS providers under their contracts.

The costs of SRAS and LRR are recovered from registered market generators and registered market customers respectively.

This purpose of this report is to provide an overview of the methodology and assumptions associated with the modelling and calculation of the AS parameters for SRAS and LRR.

All prices in this report refer to real June 2019 dollars unless otherwise stated. All annual values refer to the financial year (1 July – 30 June) unless otherwise labelled.

The following summarises the structure of the remainder of this report:

- Section 2 provides an overview of frequency AS used in the SWIS (i.e. Load Following Ancillary Service (LFAS), SRAS and LRR)
- Section 3 presents an overview of identified market and modelling developments in the WEM
- Section 4 presents an overview of modelling of the WEM
- Section 5 presents backcasting and model calibration for AS parameter modelling
- Section 6 details the SRAS and LRR modelling methodology steps
- Section 7 presents sensitivity modelling methodology and assumptions
- Section 8 presents the modelling results
- Section 9 provides analysis and commentary
- Appendix A presents market modelling assumptions
- Appendix B presents LFAS assumptions
- Appendix C presents facility-related assumptions
- Appendix D presents facility planned maintenance periods
- Appendix E contains a glossary of used terms and abbreviations

[1] Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22). Determination (31 March 2019). Economic Regulation Authority of Western Australia. Available here: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin_peak-and-margin_off-peak

- Appendix F contains information provided by AEMO in relation to the operational practice for LRR.

1.1 Quality assurance processes

General inputs and assumptions used in the modelling included:

- Numerical data obtained from MPs (cost components, heat rate data and planned maintenance periods, as presented in Appendix C and Appendix D)
- Reflection of market developments, AEMO's planning and operational practices and operational behaviours of certain thermal generators in the balancing market and the LFAS market (as identified and discussed with AEMO, and described in section 3, section 5 and Appendix B).

Data was requested by AEMO to be provided from MPs through provision of a blank Excel spreadsheet template. These inputs were then reviewed by AEMO and EY, and modified in the course of the backcasting and model calibration exercises (as described in section 5).

The modelling process was conducted subject to QA procedures, aimed at ensuring that the modelling outputs are free of material errors. Key QA activities applied throughout the modelling process involved:

- Discussions between AEMO and EY to ensure development of a common, thorough understanding of the current market environment and drivers (by means of identifying key market and modelling developments, as discussed in section 3)
- Discussions between AEMO and EY to ensure the proposed modelling approach and framework reflects the identified market conditions, AEMO's planning and operational practices and operational behaviours of certain thermal generators in the balancing and LFAS markets
- Engagement with stakeholders (stakeholder workshop) to ensure the proposed modelling approach and methodology (reflective of the preceding steps) is presented and discussed publicly
- Collecting, analysing and responding to stakeholders' submissions (as presented in section 1.2) to ensure public feedback is documented, addressed and considered in the modelling
- Backcasting and model calibration exercises (as described in section 5) to ensure that:
    - Any significant variances or material errors observed in the model outcomes relative to actual data were identified and addressed by AEMO
    - Model calibration has improved the outputs produced by the model
    - The model used in this 2019 AS parameters modelling is fit for purpose and does not provide significant modelling errors
- Test runs and de-bugging of the model, connected with sense checks of the draft results produced after model alterations
- Running the database verification tool to check for errors in database setup
- Sensitivity analysis to check whether the modelled outputs respond to varied inputs and behave in line with expectations, and to identify reasons for observed changes
- General sense checking to confirm high-level logic and drivers of the modelling results, including visual analysis (dashboards) and manual Excel re-calculations of modelled results
- Partner reviews of deliverables to ensure internal coherence and completeness logical flow.

1.2 Public consultation process

A period of public consultation was conducted based on the public version of the methodology and assumptions report (published on 18 September 2019) and an accompanying stakeholder workshop (held on 24 September 2019).

The public consultation period ended on 2 October 2019. A submission on the methodology and assumptions report was received from Synergy on 2 October 2019. No other feedback was submitted by other MPs.

Synergy's submission[2] provided feedback on the following matters:

- Calculation of the LRR requirement (with reference to section 3.4 of the report)
- Modelling of unit commitment and reliance on historical offer information (with reference to section 4 of the report)
- Information required to assess accuracy of the model assumptions and methods (with reference to section 4 of the report)
- Greenough River stage 2 start date (with reference to Appendix A.6 of the report)
- LFAS assumptions (with reference to Appendix B of the report)
- Real-time consumption of LFAS causing increase to the SRAS and LRR requirement (not addressed in the report).

AEMO's response to Synergy's submission is available on AEMO's market website[2]. A summary of Synergy's submission and AEMO's response is provided in Table 1.

Table 1: Summary of feedback from MPs

Submission topic	High level summary of submission	Submission details	AEMO response
Calculation of the LRR requirement	Proposed LRR requirement calculation method (dynamic LRR requirement set close to real-time) risks understating Synergy's actual costs incurred in LRR provision.	Synergy argued that *'[...] offer pricing and unit commitment decisions must allow for a maximum likely LRR which may be more than real-time utilisation. Any downward revision in the LRR requirement [...] would result in Synergy's costs being remunerated based on the near-real-time requirement, rather than the quantities reserved (often below cost) in Synergy's offers. Under current market arrangements, Synergy does not have an opportunity to revise its offer near real time to reduce the volume offered at the floor (and, clearly, below cost).'* Synergy submitted a recommendation that *'[...] the calculation of compensation should be included that allows for the full recovery of the relevant costs based on quantities required at the point of Synergy's gate closure and not on any downward revision of the LRR occurring after.'*	AEMO acknowledges Synergy is required to bid the forecast LRR quantity at the Minimum STEM price in accordance with clause 7A.2.9 of the WEM Rules. Due to the time difference between Synergy's gate closure and commitment, AEMO acknowledges that in certain circumstances, a cost may be incurred if the forecast LRR quantity bid differs from the quantity committed within the procurement timeframe. For the purposes of the 2020-21 financial year, AEMO anticipates the forecast LRR requirement at the time of gate closure will be the same as the LRR requirement at the time of procurement, as per section 3.4 of the Report. For the purposes of modelling, Synergy's bidding behaviour is assumed to reflect this. AEMO therefore considers that the methodology outlined in the Report will account for commitment costs incurred at Synergy's gate closure and there is no additional cost which is required to be modelled in this year's review.

[2] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services/Ancillary-Services-Parameters

Submission topic	High level summary of submission	Submission details	AEMO response
Modelling of unit commitment and reliance on historical information	Using historical offer information to derive likely future offers (in place of unit commitment modelling) is problematic.	Synergy argued that *'[w]hen deciding which facilities to commit, generation businesses take a forward view […]. Hence market participants' offers are intrinsically linked with expectations of future load, and especially with intra-day load shape.* In Synergy's view, *'[…] the assumption that historical offer information can be used to derive likely future offers (in place of unit commitment modelling) is problematic. […] It is unreasonable to assume that future bidding profiles will reflect past profiles […].'*	The modelling of generators' offers will be based on input assumptions and generator heat rates, as provided by participants, not historical offer information to derive future offers. AEMO and EY have considered unit commitment as a solution option for the ancillary services parameters review. Due to the nature of the non-linear solution methodology developed for this assessment the incorporation of a mixed integer linear programming optimisation would be computationally impractical given the review's regulatory timetable constraints. AEMO will undertake to assess the relative merits of implementation of unit commitment for the next review. For the current review, AEMO and EY will perform a backcasting exercise to examine the modelled outcomes, which includes balancing prices, generation duration curves and unit commitment, to ensure alignment with historical market outcomes. Since this response, AEMO and EY have applied a de-commitment schedule specifically for the Muja C/D and Collie facilities as described in section 5 below.
Information required to assess accuracy of the model assumptions and method	Set of information to assess accuracy of the modelling assumptions and methods.	Synergy considered that the following information is necessary to assess the accuracy of the modelling assumptions and methods: ► Dispatch metrics by facility (capacity factors, operating hours, start events) ► Annual plant availability statistics (planned and forced outages) ► Provision of AS by facility ► A load duration curve for system load net of non-scheduled generation ► A forecast balancing price duration curve. Synergy requested that this information be provided to inform stakeholders' assessment and feedback.	AEMO agrees with Synergy and will endeavour to include summary metrics and statistics in the Final Report to the Economic Regulation Authority (ERA) on 30 November 2019.
Greenough River stage 2 start date	Synergy's expected commercial operations date for the facility.	Synergy noted that it expected Greenough River stage 2 (additional 30 MW) to enter commercial operation early Q2 of 2020, not 1 October 2020.	AEMO and EY have updated the model assumptions to use the start date of 1 July 2020 for Greenough River stage 2.

Submission topic	High level summary of submission	Submission details	AEMO response
LFAS assumptions	Referencing non-Synergy participant offer behaviour.	Synergy considered that AEMO's proposal could be improved by referencing non-Synergy participant offer behaviour.	AEMO agrees with the reasoning provided by Synergy in which using LFAS offer behaviour from the period up to 27 August 2019 would better reflect the incentives for non-Synergy participation and better aligns with the proposed minimum off-peak LFAS requirement of 70 MW for 2020-21. As a result, AEMO's assumption will account for the LFAS offer behaviour from that historical period and include the LFAS offer assumptions of the new LFAS entrant that is expected to participate in 2020-21.
Impact of real-time consumption of LFAS on SRAS or LRR requirement	Possible increase in LFAS consumption will impact quantities and costs of SRAS and LRR.	Synergy requested that real-time consumption of LFAS up or LFAS down be considered when determining costs and compensation for SRAS and LRR.	AEMO proposes to incorporate a consumed LFAS quantity based on the work presented at Meeting 2 of the Transformation Design and Operations Working Group (TDOWG), showing the estimated usage of LFAS over a two-year period from August 2017 to August 2019. The empirical probability density function for LFAS usage can be fitted to a normal distribution. In the ancillary services parameters model, the consumed LFAS will be sampled from the fitted distribution at each interval. If the sampled consumed LFAS quantity is positive, then a proportion (based on the quantity of cleared LFAS that is contributing to meeting the SRAS requirement in that interval in the model) of the quantity will be deducted from the SRAS procured and if the quantity is negative a proportion (based on the quantity of cleared LFAS that is contributing to meeting the LRR requirement in that interval in the model) of the magnitude will be deducted from the LRR procured. This approach will be discussed in detail in the Final Report.

In response to Synergy's request that real-time consumption of LFAS up or LFAS down be considered when determining costs and compensation for SRAS and LRR, AEMO provided EY with a parametric distribution estimated from a sample of observed quantities of LFAS consumed. EY used the parametric distribution to generate a randomised time series of LFAS consumed for each Monte Carlo iteration. Each time series was censored at the sculpted LFAS requirement in both tails of the distribution.

For detailed approach on including LFAS consumed in the modelling, see sections 6.3, 6.4.3, 6.7 and 6.8.

1.3 ERA 2019 Determination recommendations

The ERA 2019 Determination provided certain recommendations for AEMO which related to the QA process and also specifically to the modelling of SRAS and LRR.

AEMO has addressed each of the recommendations in detail in its letter to the ERA which accompanies this report. From a modelling perspective, as a result of these recommendations EY and AEMO have:

- Undertaken a robust review of the modelling assumptions through the backcasting and model calibration exercise with final assumptions summarised in section 4.2. This included a consultation process with MPs. In this review, including through the backcasting exercise, AEMO and EY identified a number of assumptions that were queried with the relevant MPs or were amended to ensure more reasonable dispatch outcomes. These are discussed in section 5.8
- Undertaken a comprehensive backcasting and model calibration exercise as summarised in section 5
- Undertaken sensitivity modelling to validate the results of the base case modelling and test the reaction of modelling outputs to assumed variations in inputs. A discussion of the sensitivity analysis undertaken is included in section 7
- In relation to the LRR and SRAS modelling approach:
    - Forecast load was applied as per the most recent AEMO WEM ESOO (2019). Generation profiles were reviewed and applied for the modelling, as a result of the backcasting and model calibration exercise (see section 5)
    - Incorporated the impact of the ‘full runway’ (instead of ‘modified runway’) in the offer profiles of the generating units as summarised in section 3.3
    - Included a detailed summary of the operational practice for the management of LRR and the requirement used in the modelling. Details have been provided by AEMO in Appendix F and section 3.4 of the report respectively
    - The LRR modelling approach has been summarised in detail in section 6
    - AEMO has clarified the technical reasons for excluding some LFAS capacity from counting towards available SRAS in its response to the ERA’s report on the 2019-20 Ancillary Services Requirements. This is discussed in section 2.2 of the report.
- A detailed discussion of the results and possible limitations of the modelling is provided in Section 9 of the report.
- EY have undertaken QA in accordance with the approach outlined in section 1 of the report. Data and procedural checks that have been completed are described throughout the report.

The above recommendations have been considered in the development of modelling data in consultation with MPs, implementation of the modelling procedures and calculations, in substantially revising the backcasting process and through frequent consultation with stakeholders during the modelling development, application and results analysis.

2. Frequency Control Ancillary Services in the SWIS

Secure operation of a power system requires physical balance between instantaneous supply (total system generation) and prevailing demand (total system load). This balance is reflected by the key technical parameter of system frequency. The frequency operating standards for the SWIS are defined in Table 2.1 of the Technical Rules and outlined in AEMO's 2019 Ancillary Services Report (AEMO 2019 ASR) for the WEM[3] as follows:

- Normal range: 49.8 Hz to 50.2 Hz for 99% of the time
- Single contingency event: between 48.75 Hz to 51 Hz.

To balance supply with demand and manage system frequency, the WEM Rules prescribe AS categories, including:

- LFAS
- SRAS
- LRR.

Sections 2.1 to 2.6 provide background information on these services. Further details on the background of these services can be found in the WEM Rules and the AEMO 2019 ASR.

2.1 Nature of the LFAS, SRAS and LRR services

LFAS is the service of frequently and incrementally adjusting the output of one or more generators (scheduled or non-scheduled) within a trading interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations. LFAS assists in ensuring that system frequency stays between the range of 49.8 and 50.2 Hz for normal operating conditions. Capacity that is providing LFAS will also provide a contribution to frequency keeping in the event of a contingency.

SRAS or LRR are used in real time operations by AEMO to manage frequency deviations arising from single contingency events where:

- SRAS is designed to contain under-frequency excursions above 48.75 Hz
- LRR is designed to contain over-frequency excursions below 51 Hz.

SRAS is the service of holding a portion of the capacity associated with a synchronised scheduled generator or interruptible load in reserve so that the facility is able to respond appropriately to retard frequency drops following the failure of one or more generating works or transmission equipment; and, in the case of SRAS provided by scheduled generators, to respond appropriately to supply electricity if the alternative is to trigger a sudden shortfall in SWIS supply to prevent involuntary load curtailment. The sudden shortfall in supply may result from the loss of a generator or a transmission element connecting generators to the power system. SRAS assists in ensuring that generators have headroom available to ramp up very quickly and restore the supply-demand balance to manage a contingency. At times, this requires some generation capacity to be withheld from the balancing market that would otherwise be dispatched to meet the prevailing operational demand.

LRR is the service of holding capacity associated with a scheduled generator in reserve, so that the scheduled generator can reduce output rapidly in response to a sudden decrease in SWIS load. LRR is the opposite contingency service to SRAS.

[3] Ancillary Services Report for the WEM 2019 (June 2019). AEMO. Available here: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf

2.2 Technical aspects to provision of the LFAS, SRAS and LRR

LFAS is provided in two forms: LFAS up and LFAS down. LFAS up is provided to increase frequency, and LFAS down is provided to decrease frequency. LFAS is provided in response to supply and demand imbalances that occur during the normal operation of a power system. LFAS is dispatched based on commands from the Automatic Generation Control (AGC) system.

SRAS and LRR is provided in response to the supply and demand imbalance that occurs due to a contingency event involving the sudden loss of generation or the loss of demand.

- SRAS response is required to occur within either 6 seconds, 60 seconds or 6 minutes and to be sustained or exceed the required response for at least 60 seconds, 6 minutes or 15 minutes respectively (clause 3.9.3 of the WEM Rules), following a contingency event
- LRR response is required to occur within either 6 seconds or 60 seconds and be sustained or exceed the required response for at least 6 minutes or 60 minutes (clause 3.9.7 of the WEM Rules), following a contingency event.[4]

The LFAS, SRAS and LRR can only be provided by generators physically capable of providing the service. SRAS and LRR are mostly provided using governor droop response on specific synchronous thermal generators. SRAS is also provided by system Interruptible Loads (IL) via under-frequency relays. AEMO undertakes a testing and validation process to certify the ancillary service capability of generators and (in the case of SRAS) of ILs intending to provide these services.

The interaction of LFAS, SRAS and LRR to meet frequency operating standards is discussed in section 1.3 of the AEMO 2019 ASR and the letter from AEMO to ERA dated 10 July 2019.[5] In summary, the AEMO 2019 ASR explains why AEMO considers that SRAS can be provided only by a balancing portfolio facility or contracted generator or IL. AEMO's explanation is that facilities that provide capacity to meet the LFAS requirement are only considered as providing part of the SRAS requirement where those facilities have the technical capability and control systems to provide that service.

The ERA outlined in its decision on AEMO's 2019-20 AS requirements (ERA 2019 Decision)[6] that it supports excluding LFAS capacity that demonstrably cannot meet the SRAS standard.

2.3 Approved requirements for LFAS, SRAS and LRR

Clauses 3.10.1, 3.10.2 and 3.10.4 of the WEM Rules specify the standards for the LFAS, SRAS and LRR services respectively.

For the 2019-20 financial year, the LFAS, SRAS and LRR levels approved in the ERA 2019 Decision are presented in Table 2.

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[4] AEMO have advised that the manual tripping of a generator cannot be guaranteed in the required time frames. AEMO considers that this is not an acceptable means of planning to provide LRR.

[5] Available here https://www.erawa.com.au/cproot/20626/2/AEMO-response-to-ERA-s-Ancillary-Services-report---2019-20.pdf

[6] Decision on the Australian Energy Market Operator's 2019/20 Ancillary Services Requirements (12 August 2019). Economic Regulation Authority Western Australia, page 8. Available here: https://www.erawa.com.au/cproot/20630/2/AEMO-s-Ancillary-Services-Requirements-decision-201920.PDF

Table 2: LFAS, SRAS and LRR levels approved by the ERA for 2019-20, based on ERA 2019 Decision

Service	ERA approved level for 2019-20
LFAS up	85 MW between 5:30 AM and 7:30 PM 50 MW between 7:30 PM and 5:30 AM
LFAS down	85 MW between 5:30 AM and 7:30 PM 50 MW between 7:30 PM and 5:30 AM
SRAS	At least the maximum of: ► 70% of the largest generating unit ► 70% of the largest contingency event that would result in the loss of generation
LRR	Up to 120 MW, which may be relaxed by 25% down when the risk of transmission faults is determined to be low.

2.4 Economic aspects to provision of the LFAS, SRAS and LRR

LFAS is provided in a centralised competitive market operated by AEMO and priced according to LFAS market clearing prices. The AEMO 2019 ASR reports that there were three LFAS providers in 2018-19. There are currently three MPs that provide LFAS and AEMO considers there may be an additional provider in 2020-21.

There is currently no centralised competitive market for the provision of SRAS or LRR. The default provider of the SRAS and LRR is Synergy through capable generators in the Synergy balancing portfolio (SBP).

As per clauses 3.11.8 and 3.11.8A of the WEM Rules, AEMO may enter into an AS contract with MPs other than Synergy, and non-MPs who are registered as AS providers, if the AS contract provides a less expensive cost alternative to the AS provided by Synergy's registered facilities, or if AEMO does not consider that the AS requirements cannot be met with Synergy's registered facilities.

SRAS for FY 2019-20 is sourced as follows:

- 42 MW based on a long term interruptible load contract
- 21 MW based on short term non-Synergy contracts
- Reserves above contracted amounts are provided by Synergy.

No contracts have been procured for LRR historically or in 2019-20, predominantly as the value of the service was relatively low. Until 31 August 2019, SRAS costs borne by generators were allocated based on a 'modified runway' method. A rule change to introduce a 'full runway' (as described in RC_2018_06 Rule Change) was accepted by the Rule Change Panel and became effective on 1 September 2019. Please refer to Section 3.3 for details.

LRR costs are borne by market customers based on their share of consumption (clause 9.9.1 of the WEM Rules). As a general principle, clause 3.11.9 of the WEM Rules specifies that where AEMO intends to enter into an ancillary service contract, it must:

- Seek to minimise the cost of meeting its obligation to schedule and dispatch facilities (or cause them to be scheduled and dispatched) to meet the ancillary service requirements in each trading interval in accordance with Chapter 7 of the WEM Rules (clause 3.11.9(a) of the WEM Rules)
- Give consideration to using a competitive tender process, unless AEMO considers that this would not meet the requirements of clause 3.11.9(a) of the WEM Rules.

2.5 SRAS remuneration basis and the Margin Values parameters

Given the lack of a centralised competitive market for SRAS, Synergy's remuneration for provision of this ancillary service is based on an administered mechanism specified in the WEM Rules.

Because provision of SRAS means withholding some capacity from the balancing market and making it available for contingency management, units providing SRAS incur an opportunity cost.

Conceptually, this opportunity cost should be compensated through payments for each half-hourly trading interval when Synergy is providing SRAS (Synergy SRAS availability payments).

Based on the ERA 2018 Determination,[7] the opportunity cost of SRAS for a generation unit (that is able to provide the service) is understood as being equivalent to the net revenue forgone in the balancing market due to its reservation of capacity.

Consistent with the approach used in previous years, EY's calculation of the Margin Values will assume that a generation unit's net revenue forgone in the balancing market is equal to:

- The loss of revenue due to reduced energy sales attributable to the generation unit's reservation of capacity, minus
- The operating costs that would have otherwise been incurred if the unit had not reserved its capacity. The calculation of reduced operating costs will account for changes to the efficiency of a unit associated with its reserving of capacity in line with the approach proposed by the ERA in the ERA 2018 Determination.

Beside the balancing price and the quantity of SRAS, the key parameter impacting the amount of Synergy remuneration for provision of SRAS is the Margin Values.

Clauses 3.13.3A(a)(i) and 3.13.3A(a)(ii) of the WEM Rules stipulate that in proposing the Margin_Peak and Margin_Off-Peak values:

> *… AEMO must take account of:*
>
> - *the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during … [Peak/Off-Peak] Trading Intervals; and*
> - *the loss in efficiency of Synergy's Scheduled Generators that [AEMO] System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during … [Peak/Off-Peak] Trading Intervals that could reasonably be expected due to the scheduling of those reserves[.]*

These clauses of the WEM Rules imply that Synergy's SRAS payment should compensate Synergy for the opportunity cost it incurs by being the default supplier of SRAS. This cost is referred to as Synergy's availability cost. The forecasting of Synergy's availability cost is a key component in the overall calculation of the Margin_Peak and Margin_Off-Peak values.

Margin_Peak and Margin_Off-Peak values are set for the next financial year based on submission by AEMO (by 30 November) and determination by the ERA (by 31 March).

Calculation of Margin Values requires forecasts of the balancing prices, the quantities of SRAS provided by Synergy and Synergy's opportunity cost in each trading interval. Once these forecasts are available, the value of Margin_Peak and Margin_Off-Peak can be estimated.

[7] Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year. March 2018. Economic Regulation Authority Western Australia. Available here: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin_peak-and-margin_off-peak

The SRAS parameters that are the focus of EY modelling are summarised in Table 3. A detailed methodology for deriving Margin Values is provided in Section 4.

Table 3: SRAS parameters to be determined as part of the modelling

Parameter	Description
Margin_Peak and Margin_Off-Peak	Margin Values are a parameter used as a multiple applied against the balancing price to compensate Synergy, as the default provider of SRAS, for the opportunity cost of making capacity available for the service. Margin Values are applied to the balancing price and the quantity of SRAS provided to determine an 'availability payment' to Synergy, which reflects the opportunity cost. Currently, the Margin Values are also the basis of payments to other SRAS providers, being a contract price discount percentage to the Margin Values. Margin Values are calculated for peak and off-peak trading intervals.
SR_Capacity_Peak and SR_Capacity_Off-Peak	In accordance with clauses 3.22.1(e) and 3.22.1(f) of the WEM Rules, the SR_Capacity values are the modelled requirement for SRAS for peak and off-peak trading intervals assumed in forming the Margin Values. AEMO must use the SR_Capacity values that are derived while forming the Margin Values for the purpose of settlements in accordance with clause 9.9.2 of the WEM Rules. SR_Capacity values are calculated for peak and off-peak trading intervals and are used by AEMO for determining the quantity of SRAS to compensate providers in accordance with clause 9.9.2(f) of the WEM Rules.

2.6 LRR remuneration basis and the Cost_LR parameter

Given the lack of a centralised competitive market for LRR, Synergy (as a default provider) is remunerated for provision of this ancillary service on the basis of an administered mechanism specified in the WEM Rules.

The general parameter to provide remuneration for LRR is described in 3.13.3B of the WEM Rules. This parameter is called Cost_LR.

As per clause 3.13.3B Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service.

Generators that provide LRR are compensated through the 'L' component of Cost_LR.

The 'R' parameter applies for compensation of generators capable of providing system restart services, i.e. generators that are capable of 'black-starting' to assist in the re-energisation of the SWIS for energising the transmission network and other generators after a system black-out. The 'R' parameter is not considered in this report and will be provided by AEMO separately.

While the WEM Rules specify the costs that Synergy should be compensated for when providing SRAS (clause 3.13.3A), no such guidance exists for LRR (clause 3.13.3B). In the 2018 review, AEMO and EY considered a number of potential costs associated with the provision of LRR identified within the modelling processes. These costs are summarised in Table 4.

Table 4: Costs that may be incurred as a result of providing LRR

Parameter	Description
LRR availability costs	**Costs of a facility providing LRR not recovered through other market mechanisms.** ► Synergy is required to offer the quantity that is capable of providing LRR at the market floor price to ensure this capacity will always be dispatched ► As such, facilities within the balancing portfolio may be compensated at a balancing price below their short-run marginal cost (SRMC) to meet the LRR requirement

Parameter	Description
LRR response costs	**Energy profits forgone by facilities providing LRR during a load rejection event.** ► A generating unit may be instructed to curtail its generation output in response to an actual load rejection event and as a result would incur forgone energy profit
Other facility costs	**Energy profits forgone and de-commitment costs from facilities not providing LRR** ► There are potential energy profits forgone (or de-commitment costs) from facilities that are not dispatched due to Synergy being the default provider of LRR ► For example, if a generator unit is ramped down (or de-committed), to maintain supply-demand balance in response to another unit providing LRR, there may be energy profits that are forgone ► De-commitment of units occurs where the LRR requirement would reduce a generator's output below its minimum generation level

For further calculations, LRR availability costs and LRR response costs will be included.

Other facility costs will be excluded from the calculations. Consistent with last year's approach, other facility costs will be excluded from the LRR estimate of the 'L' parameter of Cost_LR as AEMO does not consider it to be a cost directly associated with providing LRR. Refer to page 9 of the 'Load rejection reserve service cost for 2019-20, 2020-21 and 2021-22'.[8]

A detailed methodology for deriving the LRR estimate of the 'L' parameter of Cost_LR is provided in Section 4.

[8] Load rejection reserve service cost for 2019-20, 2020-21 and 2021-22. Available here: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/load-rejection-cost_lr

3. Identified market and modelling developments

EY and AEMO have identified the following, based on observed and expected market changes since the previous AS review, which are either developments in the WEM relating to the provision of AS that will impact the financial year 2020-21 or improvements to the modelling approach delivered for this year:

- Possible changes in the size of the single largest supply-side contingency
- The sculpted approach to determining the volume of LFAS up and LFAS down
- The 'full runway' method for allocation of SRAS costs among MPs
- The dynamic approach to calculating the LRR requirement
- The requirement to maintain certain levels of the ready reserve standard
- The implementation of the Generator Interim Access (GIA) solution
- The procurement of non-Synergy SRAS
- The possible reduction in LRR as a result of rooftop solar PV.

Sections 3.1 to Section 3.8 discuss the identified current market developments.

3.1 Single largest supply-side contingency

The single largest supply-side contingency impacts the required levels of SRAS in any dispatch interval. Historically, this has been set based on the loss of output from the single largest generating unit synchronised to the SWIS.

AEMO has reviewed this matter and has provided the following information:

> The AEMO 2019 ASR states that "due to the connection of new generators in 2020, it is likely that a single transmission line could be the largest generation contingency for certain periods of time. Depending on system conditions at the time, AEMO may need to increase the SRAS requirements or reduce the size of this largest contingency. AEMO is currently working with Western Power and the broader industry to determine the most appropriate action while maintaining power system security".
>
> AEMO has discussed this matter with MPs at the Market Advisory Committee and notes that discussions on both the technical management of the situation and possible rule changes in relation to market issues are ongoing.[9] The following summary presents AEMO's understanding of the operational practice that it anticipates may be in place on 1 July 2020 at the time of submission of the report.
>
> The new generators referred to in the AEMO 2019 ASR are a 210 MW and a 180 MW intermittent non-scheduled generator respectively, which are both expected to be in operation by Q3 2020. The generators are connecting on the single 330 kV line between Neerabup Terminal and Three Springs Terminal. A network fault on the NT NBT TST 330 kV line will trip both generators and result in a reduction of load normally fed through this line. Without any intervention, this will become the largest SWIS generation contingency. This will occur when the combined output of both generators, less the expected reduction in load, is in excess of the output of the largest single generator. In certain conditions, a network fault between Northern Terminal and Neerabup Terminal will also trip Newgen Neerabup. Up to 730 MW generation could potentially be lost, but

[9] See meeting papers for 11 June 2019 and 29 July 2019 meetings available here https://www.erawa.com.au/rule-change-panel/market-advisory-committee/market-advisory-committee-meetings

it is expected that the network operator will prevent this scenario from arising. Under normal operating conditions, the largest expected net contingency is 340 MW.

As per the AEMO 2019 ASR, the quantity of SRAS that needs to be procured at every interval is 70% of the largest contingency which includes the transmission line contingency. The largest contingency may depend on the output of the intermittent non-scheduled generators. This will increase the quantity of SRAS required in some intervals.

In practice there may be a small number of instances when SRAS of greater than 70% of the largest contingency is required. These situations will typically occur during times of low inertia, low system load and large contingency sizes. The approach to manage these situations is still under consideration by AEMO in preparation for the connection of these generators.

For the purposes of the AS parameters modelling, the following was assumed:

- The SRAS requirement is set at 70% of the largest supply-side contingency
- If the model cannot meet the SRAS requirement, then a shortfall will be reported[10]. This shortfall will be reflective of a possible and likely operational response to reduce the contingency size by constraining off the intermittent non-scheduled generators. These generators may be entitled to constrained compensation under the WEM Rules and this may impact the balancing price. However, for the purposes of the modelling these impacts will not be considered.

The modelling approach assumes that carrying SRAS of 70% of the largest contingency will always be sufficient to maintain system security. However, AEMO has indicated that there may be times where 70% of the largest contingency is not sufficient to maintain system security. There is currently no information on how often this will occur or the magnitude of the increase in SRAS required in these intervals. On this basis, AEMO and EY propose that this is a necessary and reasonable simplification for the purposes of modelling the 2019 AS parameter modelling. The approach will be reassessed for the 2020 AS parameter modelling.

3.2 LFAS market developments

In recent years the LFAS requirement has been set at 72 MW for both LFAS up and LFAS down. To account for variability from increasing penetration of behind the meter PV facilities and other non-scheduled generation in the SWIS, AEMO identified the need to vary the LFAS requirement using a time-of-day profile.

The following requirements have been proposed by AEMO and approved by the ERA for 2019-20:

- 85 MW from 5.30 AM to 7.30 PM
- 50 MW from 7.30 PM to 5.30 AM.

The LFAS requirements for 2020-21 have yet to be defined.

AEMO has reviewed this matter and has provided the following information:

The LFAS requirements for FY 2020-21 are yet to be determined and is subject to approval of the ERA in June 2020 and will be based on AEMO analysis in the 2020-21 Ancillary Services Report.

Preliminary simplified analysis performed by AEMO suggests that, at a minimum, the peak time LFAS requirement (5.30 AM to 7.30 PM) is expected to increase to 116 MW, and, at a minimum,

[10] It is noted that no SRAS shortfall events were observed in the modelling.

the off-peak time LFAS requirement (7.30 PM to 5.30 AM) is expected be set to 70 MW. The preliminary analysis considered and included:

- The impact of Badgingarra Wind Farm
- The use of largely coincident output of new facilities with a combination of Badgingarra Wind Farm and Emu Downs Wind Farm
- An estimate of an additional 20 MW average impact on LFAS requirements associated with the new wind farms overnight and 23 MW during the day (assuming no constraints)
- An average of 8 MW additional LFAS can be attributed to an additional year's rooftop PV impact.

For the purposes of the AS parameters modelling, AEMO has instructed EY to assume that the LFAS requirement for 2020-21 will be:

- 116 MW from 5.30 AM to 7.30 PM
- 70 MW from 7.30 PM to 5.30 AM

Section 2.2 of this document discussed the interaction of LFAS, SRAS, and LRR to meet frequency operating standards.

AEMO has reviewed this matter and has provided the following information:

AEMO has clarified the technical reasons for excluding some LFAS capacity from counting towards available SRAS.[11]

The main justification is that LFAS capacity from units that are not able to meet all the technical requirements for SRAS following a contingency should not be considered as counting towards available SRAS. e.g. required response within 6 seconds.

Currently, the only facilities that provide both LFAS and SRAS are all balancing portfolio facilities.

The ERA outlined in the ERA 2019 Decision that it supports excluding LFAS capacity that demonstrably cannot meet the SRAS standard.

The 2019 AS parameters modelling will assume only LFAS capacity from facilities that are certified for both LFAS and SRAS to be considered as counting towards available SRAS.

3.3 Full runway method for allocation of SRAS costs

The cost of providing the SRAS is recovered from all generators synchronised to the system with output of at least 10 MW in a given trading interval.

Until 31 August 2019, the method used to allocate SRAS costs to individual generators was the 'modified runway' method.

Under the 'modified runway' method, the costs for the SRAS were allocated based on a set of predetermined block ranges, with increasing costs for each block. All generators that fell within a block would pay an equal share of that block's SRAS costs. Therefore, if two generators were in the same block, both would pay an equal proportion of the SRAS costs for that block, despite their possibly different generation amounts. Generators with output at the bottom of a block subsidised generators with output near the top of a block.

[11] http://www.erawa.com.au/cproot/20626/2/AEMO-response-to-ERA-s-Ancillary-Services-report---2019-20.pdf

A rule change to introduce 'full runway' (as described in RC_2018_06 Rule Change) was accepted by the Rule Change Panel and came into effect on 1 September 2019.

Under the 'full runway' method, SRAS costs are allocated to each generator in a more granular way, according to the causer pays principle, with each generator paying SRAS costs in line with the generation of its facility (except for generators with an applicable capacity of 10 MW or less). This is expected to remove the potential for distorted bidding behaviour that existed under the previous 'modified runway' method, allowing generators to offer more of their applicable capacity into the balancing market, thus producing more competitive prices.

The ERA 2019 Determination noted that the 2018 AS parameter modelling did not appear to correctly account for the effect of SRAS liabilities on generators' balancing offers. It was suggested that the modelling overestimated the output of some generators as compared to the output observed in reality.

AEMO has reviewed this matter and has provided the following information:

> The allocation methodology for SRAS costs imposes a higher weighted cost on generation output at higher levels within a trading interval. This escalating cost can influence Market Participants' balancing submissions including limiting the output of the largest generators to reduce SRAS costs.
>
> The amending rules for the 'full runway' allocation of spinning reserve costs (RC_2018_06) became effective on 1 September 2019. Market and settlement impacts will not be reliably known until this change has been in place for some time. This rule change is expected to reduce distortions in bidding seen under the 'modified runway' method. However, SRAS costs will still escalate at higher output ranges.
>
> In practice it is expected that MPs will reflect their anticipated SRAS costs in their balancing submissions and take into account factors such as the balancing price and the bidding behaviour of other MPs.

For the purposes of the AS parameters modelling, a comprehensive implementation of the impacts of the 'full runway' method on each generator's cost curves will be computationally expensive. This is because SRAS costs influence generation costs, generation costs influence generation offers, generation offers influence dispatch outcomes and dispatch outcomes form the basis for SRAS cost allocation. EY's proposed approach is an approximation that allows the model to account for the 'full runway' method as follows:

- Use the 'full runway' method formula[12] to allocate the past modelled SRAS cost to past modelled generation output levels
- Apply regression analysis to estimate the relationship between the past modelled SRAS cost and past modelled generation output levels
- Modify offer curves of generators to reflect the estimated relationship derived from the regression.

3.4 Calculation of the LRR requirement

The ERA 2019 Determination for the period 2019-20 to 2021-22 considered that the LRR costs proposed by AEMO were overstated due to modelling based on an LRR requirement different from observed. The ERA's view was that the modelling had been based on meeting a firm LRR

[12] As specified in the Final Rule Change Report: Full Runway Allocation of Spinning Reserve Costs. 30 April 2019 (RC_2018_06 Rule Change). Available here: https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2018_06

requirement of 120 MW throughout all trading intervals, while in practice throughout 2017-18 based on the AEMO 2018 ASR:

- The LRR was between 90 MW and 120 MW for 14.9% of the time
- The LRR was operated below 90 MW for 6.5% of the time.

The ERA considered that the modelled output did not align with the WEM Rules or AEMO's actual practice and therefore would have overestimated the cost of LRR. The ERA considered the modelling foundation for the current LRR value to be credible, but the assumptions to be unrealistic.

AEMO has provided a detailed overview of the operational practice for managing LRR which is included as Appendix F.

The LRR requirement approved for the 2019-20 financial year in the ERA 2019 Decision is *"up to 120 MW that may be relaxed by 25% down when the risk of transmission faults is determined to be low"*.

As per the AEMO 2019 ASR, AEMO is conducting a trial for a dynamic LRR requirement. If the trial is successful, AEMO will use the experience to inform the requirements in the 2020-21 financial year. For 2019 AS parameter modelling, an assumption needs to be made on the LRR requirements for 2020-21 before the results of the dynamic LRR trial are fully known.

AEMO has reviewed this matter and has provided the following information:

The dynamic LRR formulation incorporates physical aspects of the power system, including:

- Setting the upper limit of the LRR requirement based on the largest credible contingency in real-time
- Allowing for the consequential corresponding change in load as a result of an increase in frequency, known as load relief
- Where required by the Network Operator as a requirement of connection to the SWIS, allowing for the operation of facility protection systems in response to over-frequency (thus reducing the output of the facility)

Based on early results of the dynamic LRR trial, AEMO expects to procure sufficient LRR through commitment of specific facilities prior to the trading interval to ensure the dynamic LRR requirement can be met in real-time, using the following formula:

where:

$$LRRreq = \min(120, \max(BGM, EGF, 70)) - \max\left(30, \frac{3}{200}(SystemTotal - \max(BGM, EGF))\right) - WF$$

- $LRRreq$ is the dynamic LRR requirement
- BGM and EGF are the loads at Boddington Gold Mine and the Eastern Goldfields region respectively (in MW). At the time of procurement, both loads are assumed to be <120 MW. In the real-time assessment, they will be based on actual telemetered loads (up to a maximum of 120 MW)
- $SystemTotal$ is the SWIS total system load (in MW). At the time of procurement, the forecast total system load is used. In the real-time assessment, it will be based on the actual telemetered load

- WF is the aggregate partial outputs from selected wind farms with the required protection settings to reduce the LRR requirement (in MW). WF is assumed to be zero at the time of procurement, due to the uncertainty of wind farm generation output within the procurement timeframe. In the real-time assessment, they will be based on actual wind farm output.

The dynamic LRR formulation has not been operationalised. There are a series of trials and operational requirements which must be conducted and met, prior to adopting the aforementioned approach. If the trials are successful, AEMO expects to undertake dispatch planning and to dispatch Synergy facilities to ensure that the dynamic LRR requirement can be met at the time of procurement and maintained in real-time.

The LRR requirement to be considered when ensuring there is sufficient generation on line to provide the service, will take into account the largest expected credible load contingency. An allowance for the estimated load relief will reduce this requirement. Based on experience from the first phase of the trial, which only impacted the real-time operational philosophy, the next phase will review the impact of reducing the LRR requirement when ensuring adequate generation is committed to meet the requirement (prior to real-time). At first a fixed (but lower) value will be considered, and depending on the operability of this outcome, a variable value may be considered. Practical limitations may result in this not being a feasible option going forward.

Subsequent to procuring LRR, AEMO expects to compare the procured LRR against the real-time dynamic LRR requirement. Where the procured LRR is insufficient, AEMO will re-dispatch generation to meet the LRR requirements. However, in circumstances where the procured LRR exceeds the real-time dynamic LRR requirement, AEMO does not expect to actively reduce the procured LRR to align with the dynamic LRR requirement. This is due to a number of reasons, including the provision of LRR from units cleared for energy and/or LFAS down (which thus should not be re-dispatched), and to maintain a margin for wind, solar and system load volatility (which occurs in real-time). This is discussed further in Appendix F.

EY's methodology for 2019 seeks to consider AEMO's proposed LRR approach outlined above. For the purposes of the AS parameters modelling, EY will model the LRR requirement based on the procurement timeframe outlined above.

3.5 Modelling ready reserve standard

Clause 3.18.11A of the WEM Rules specifies the ready reserve standard as a requirement that the available generation and demand-side capacity at any time is sufficient to cover:

- 30% of the total output (including parasitic load) of the generation unit synchronized to the SWIS with the highest total output at that time, plus the minimum frequency keeping capacity (as defined in clause 3.10.1(a)). This must happen within 15 minutes.
- In addition to the above, 70% of the total output (including parasitic load) of the generation unit synchronized to the SWIS with the second highest total output at that time, plus the minimum frequency keeping capacity (as defined in clause 3.10.1(a)). This must happen within four hours.

In previous AS parameters modelling, the requirements of the ready reserve standard were not modelled. However, this could be modelled to improve the accuracy of the simulated dispatch outcomes.

AEMO has reviewed this matter and has provided the following information:

AEMO has an obligation to meet the ready reserve standard in accordance with clause 3.18.11A of the WEM Rules. In practice, ready reserve is provided exclusively by Synergy gas-fired facilities, and is maintained through keeping specific units offline to meet the standard.

EY will model AEMO's operational practice, ensuring that specific Synergy units are kept in reserve and not available for provision of SRAS or LRR.

3.6 Modelling of Generator Interim Access network constraints

The Generator Interim Access (GIA) solution enables the connection of new entrant generators on a constrained basis. In previous AS parameters modelling, no facilities connected under GIA were operational, but new facilities have been connected (or are expected to be connected) within this review period.

AEMO has reviewed this matter and has provided the following information:

GIA constraints are typically unique to the facility and driven by different technical requirements.

At present, there are only two operational GIA facilities in the SWIS (Badgingarra Wind Farm and Beros Rd Wind Farm), however this number is expected to rise to five facilities within the AS parameters review period.

To reflect the possible impact that the GIA solution will have on the dispatch outcomes of GIA-connected generators, AEMO considered the following options:

- Implement a set of GIA pre-dispatch constraint equations
- Approximate the impact that GIA constraints may have on new entrant generator connections by applying reduced capacity factors on facilities (where the data is available)
- Assume all generators have an unconstrained connection.

It is AEMO's understanding that the GIA constraint equations for the new facilities have not yet been developed by the Network Operator, so implementing GIA pre-dispatch constraint equations is not feasible.

Of the operational GIA facilities, there are less than 9 months of operational data on the effects of GIA constraints. It is possible to impose GIA capacity factor constraints for the facilities where data is available, but the treatment of new facilities in a fair and consistent manner needs to be considered.

GIA capacity factor constraints could also be imposed on all new GIA facilities, but the question arises as to the degree of capacity reduction that is appropriate. Without an understanding of the nature of the constraint equations that will be applied to these new facilities, the amount of capacity reduction cannot currently be predicted a priori.

EY understands that:

- AEMO has requested guidance from Western Power on the expected level of curtailment for future GIA facilities
- Western Power has indicated it cannot provide such an assessment, in part due to the constraint equations for those facilities having not yet been developed.

For the purposes of the AS parameters modelling, EY has received recent market data from AEMO showing that the level of curtailment experienced by existing GIA connected facilities is not significant under system normal conditions.[13] EY as a result will not apply a reduced capacity factor constraint for the facilities connected under GIA arrangements. This approach will be reassessed for the 2020 AS parameter modelling in subsequent reviews.

[13] The Margin Values review is modelled under system normal conditions. AEMO advises that GIA generators may be impacted due to planned and unplanned network outages, however that has not been considered in the review.

3.7 Non-Synergy SRAS procurement

Clause 3.11.8 of the WEM Rules specifies the circumstances under which AEMO may enter into an AS contract for non-Synergy SRAS. The quantity and providers of non-Synergy SRAS assumed for the modelling can impact the margin values, as it affects the quantity of SRAS reserve provided by Synergy and modelled dispatch outcomes.

AEMO has reviewed this matter and has provided the following information:

> The procurement of non-Synergy SRAS occurs after AEMO proposes the margin values to the ERA, therefore the quantity of non-Synergy SRAS in the financial year 2020-21 is currently unknown.
>
> To assist in determining the assumptions for the non-Synergy SRAS quantity, AEMO has undertaken an expression of interest for the financial year 2020-21. AEMO has assessed the submissions and determined a likely quantity of non-Synergy SRAS assumed for AS parameters modelling as follows:
>
> - 42 MW based on a long-term interruptible load contract
> - 21 MW based on a short-term interruptible load contract.
>
> This represents continuation of the current SRAS contracts for FY 2019-20.

For the purposes of the AS parameters modelling, EY will model the non-Synergy SRAS determined by AEMO.

3.8 Potential for reduction in LRR as a result of rooftop PV tripping at high frequency

The ERA 2019 Determination made a recommendation to consider and account for the automatic contribution from inverter-connected generation such as solar PV that would trip or decrease output when over-frequency occurs, due to its over-frequency settings.

AEMO has reviewed this matter and has provided the following information:

> AEMO only has access to coarse estimates of aggregate output from rooftop PV installations via distributed irradiation measurements, not direct measurement from the PV inverters. Moreover, AEMO has no visibility on the over-frequency response of individual (or groups) of PV inverters, which are subject to material differences depending on compliance with different versions of AS/NZS 4777.
>
> As a result, AEMO has neither the means to quantify nor monitor the amount of aggregate PV output reduction in response to over-frequency events. Without visibility this limits AEMO's ability to incorporate over-frequency responses from rooftop PV into the dynamic LRR requirements.

For the purposes of the AS parameters modelling, EY will not model the reduction in LRR as a result of rooftop PV tripping at high frequency.

4. Modelling of the Wholesale Electricity Market

4.1 Wholesale electricity market modelling

Wholesale electricity market modelling in this review is conducted using EY's in-house market dispatch modelling software 2-4-C®. 2-4-C® seeks to replicate the functions of the real-time dispatch engines used in wholesale electricity markets with dispatch decisions based on market rules, considering generator bidding patterns and availabilities to meet regional demand in a period.

The WEM is modelled as a single node gross pool dispatch energy market. Modelling for this review is on a trading interval (30 minute) granularity in a time-sequential manner. This captures the variability of renewable generation, thermal unit outages (both unplanned and planned) and ramp rate limitations, as well as the underlying changes to system demand. As a modelling improvement for this year, 2-4-C® will include separate modelling of the LFAS market to determine clearing quantities for use in the balancing market.

At a high level, for each trading interval in the defined study period, 2-4-C® simulates the dispatch of generators to meet a forecast load demand target, subject to defined constraints and the outcomes of the LFAS market. Constraints in the model can represent a range of physical limits associated with network power transfer limits, generator plant capability, contractual supply limits and more.

Each generator unit is modelled individually. The outputs that are reported from the model include the output of each generator (in MW or GWh), the loss factor adjusted market clearing price (in $/MWh),[14] presence of unserved energy (USE)[15] and generator availability amongst many other metrics.

4.2 Data and input assumptions

The general inputs and assumptions employed in the WEM simulation model have been agreed with AEMO to reflect AEMO's planning and operational practices.

To ensure the input assumptions have been reviewed and modified where necessary, and to ensure the model is fit for purpose and does not produce material errors, backcasting and model calibration was conducted. Key changes resulting from the backcasting exercise involved:

- Changes to Synergy's assumed gas fuel price and fuel prices of selected IPPs
- Introduction of observed operational behaviours for certain generators.

Details on the backcasting and model calibration exercise have been provided in section 5.

In practice, electricity market modelling of this nature is highly complex and involves establishing a large set of data and input assumptions that are often inter-related. These input assumptions can be grouped into four general categories which are described at a high level below. Figure 1 provides a high-level overview in diagram form, including categorising the input assumptions in four categories.

[14] The balancing price, constrained by maximum and minimum energy price limits

[15] Unserved energy can be the result of voluntary or involuntary load shedding. Voluntary load shedding is modelled as Demand Side Participation offering into the market as a response to high pricing events. Involuntary load shedding is the result of insufficient capacity to meet the load demand in a trading interval, requiring system load to be curtailed and occurs as a last resort.

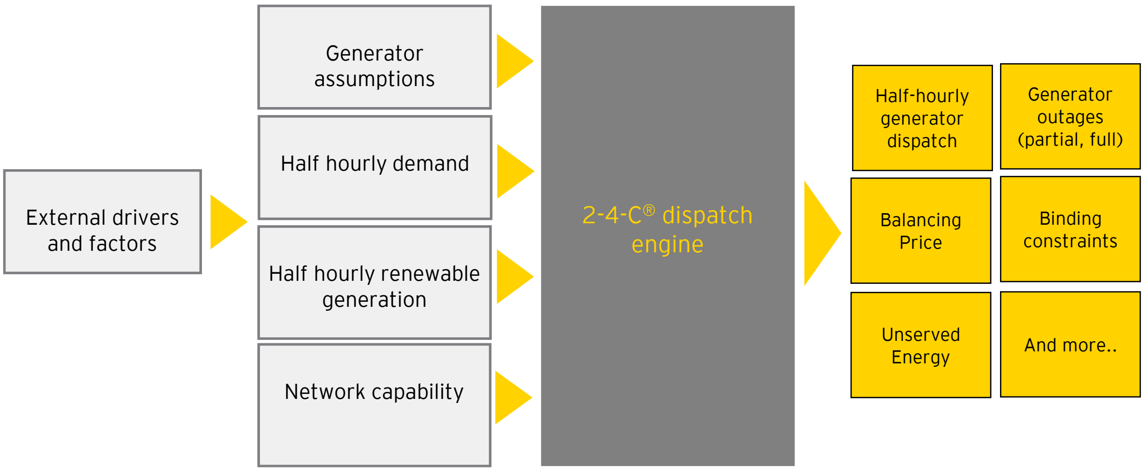


Figure 1: Simplified high level overview of the inputs and outputs to 2-4-C®

The following points describe the four types of input assumptions in Figure 1:

- Generator assumptions are the relevant technical and cost parameters for each existing and new entrant generator in 2-4-C®. These assumptions include generator bidding profiles, generator heat rates, ramp rates, fuel costs, fixed and variable operating and maintenance costs, emissions factors, outage rates (including mean time to repair and mean time to fail), marginal loss factors, planned maintenance periods, new entrant technology capital costs, the estimated relationship between SRAS liabilities and generation output, and more[16]
- Half hourly demand involves using half hourly data trace based on assumptions of peak demand and annual energy projections, historical half-hourly demand, the uptake of rooftop solar PV, electric vehicles (EVs) and behind-the-meter battery storage, using data sourced primarily from AEMO's WEM Electricity Statement of Opportunities (ESOO).[17] EY's half-hourly profile modelling tools combine these together to produce forecasts of the future half-hourly demand
- Network capability defines power transfer limits and network limitations that constrain the physical dispatch of generator units and dispatchable loads. In actual market dispatch and 2-4-C®, these are typically implemented in the form of network constraint equations. The WEM currently operates with a limited number of network constraint equations using the GIA solution, and includes a number of post-contingent generation curtailment schemes. Modelling of GIA is discussed in Section 3.6
- Renewable generation modelling involves developing half-hourly available generation profiles for each modelled wind or solar farm. The input assumptions and data include historical wind and solar resource data that is used to create expected/historical annual energy availability.

Figure 2 shows a detailed flow diagram detailing the interactions between 2-4-C®.

[16] Generator synchronisation times are not explicitly modelled.

[17] AEMO WEM Electricity Statement of Opportunities. Available here: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

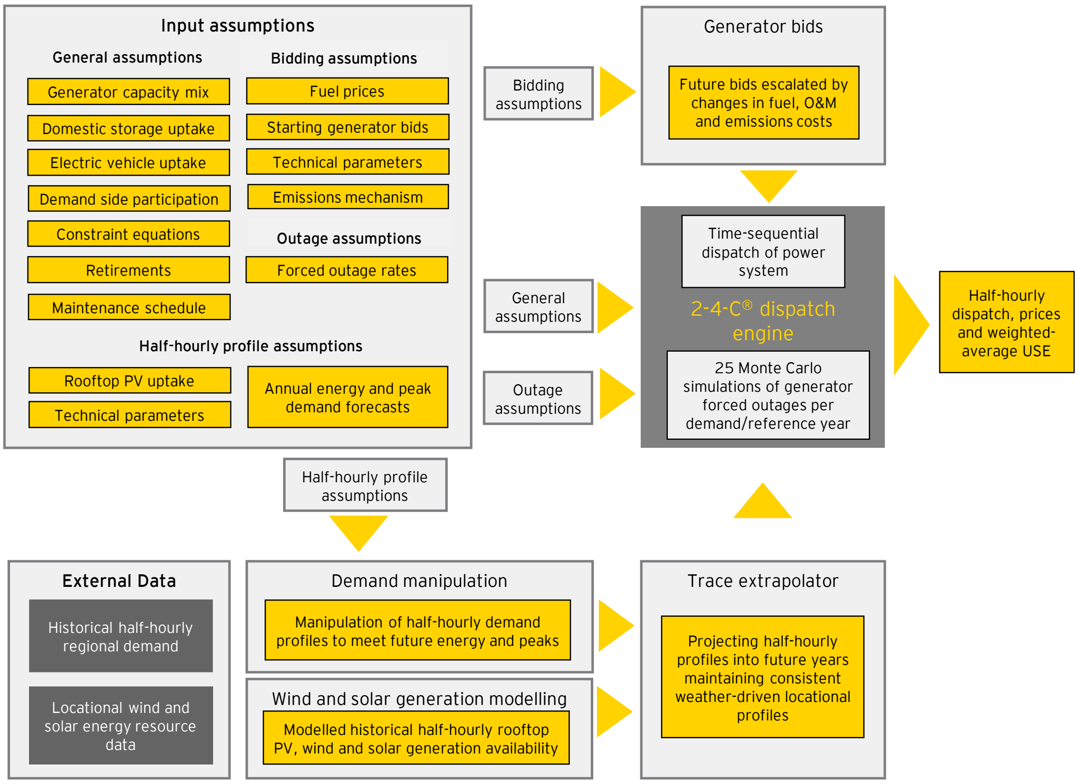


Figure 2: Data flow diagram for the market simulations

Market and facility-related assumptions applied for the modelling of SRAS and LRR are presented in Appendix A, Appendix B, Appendix C and Appendix D.

4.3 Simulation parameters

The potential for any particular market outcome in the WEM is probabilistic. Various combinations of prevailing customer demand, availability and costs of conventional and intermittent generation, energy storage devices, demand side participation, transmission network capability and generator availability will influence market outcomes.

Within market modelling, Monte Carlo simulations of generator outages, multiple reference years of historical data and probability of exceedance (POE) peak demand forecasts can be taken into account. This captures the probabilistic nature of key half-hourly variations in the WEM in the overall outcomes reported.

Each Monte Carlo simulation iteration models different profiles of unplanned outage events on generators according to assumed outage rate statistics. The base case modelling will deploy 25 Monte Carlo iterations of generator outages for the study period based on a single reference year, using the 50% POE demand modelled, representing AEMO's expected demand. Five Monte Carlo iterations are completed for the sensitivity cases.

Table 5 provides a summary of key simulation parameters.

Table 5: Simulation parameters

Simulation parameter	Description
Demand profiles	The 50% POE values for the forecast year will be modelled in a half-hourly time sequential series.
Reference years	Different reference years will have variability in terms of the half-hourly demand, wind and solar profiles according to the weather patterns in those years. 2018-19 reference year has been used for modelling.
Monte Carlo iterations	Twenty five Monte Carlo iterations[18] of thermal generator outages (full and partial unplanned outages) were modelled for the Base scenario. Five Monte Carlo iterations are completed for sensitivity cases.
Results	All results are provided as a weighted average over all Monte Carlo iterations unless otherwise specified.
Study period	The study period for the calculation of Margin Values and the SRAS requirement is from 1 July 2020 to 30 June 2021.
	The study period for the calculation of the 'L' component for Cost_LR is from 1 July 2020 to 30 June 2021.

[18] Twenty-five (25) iterations of Monte Carlo simulations produce converged dispatch outcomes suitable for the purposes of the modelling.

5. Backcasting and model calibration for AS parameter modelling

During the 2019 AS parameter review, EY undertook a backcasting and calibration exercise of EY's dispatch and AS optimisation model.

The main purpose of the backcasting and model calibration exercise was to provide confidence in the model's ability to replicate historical dispatch and price outcomes (within an acceptable level of accuracy).

As mentioned in Appendix A.9, the model calibration exercise was used to inform the fuel price to be used for modelling Synergy gas-fired units, as well as necessary adjustments to input data provided by MPs for all generation facilities. Model calibration also took into account insights gained from backcasting against 2018-19 actuals (a backward-looking process by nature).

EY used the information provided to AEMO as part of a market participant information request and the modelling methodology developed for this review. This approach allowed EY and AEMO to use the most recent information provided to AEMO in conjunction with feedback provided during the public consultation period in the backcasting exercise.

EY compared the dispatch outcomes simulated pre-optimisation and post-optimisation against the actual outcomes in the 2018-19 financial year. This involved EY simulating the actual half-hourly demand observed in the WEM, using actual wind and solar generation output and modelling generator outages as they have occurred (and according to the data available).

Throughout any given year, generators experience changes in their operating parameters as well as fuel availability and pricing. However, data describing such changes is not available. The backcasting task was then used to approximate the typical operating and fuel parameters for each generator.

This section describes the input data used for the backcasting and model calibration exercises, the methodology and key outcomes.

The backcasting exercise presented here was undertaken using EY's dispatch and AS optimisation model at the time of backcasting. As a result of the QA processes (including the backcasting analysis) two improvements have been subsequently made to the model for the final modelling studies to capture expected operational behaviours:

1. A heuristic analysis of large thermal generation unit behaviour has been applied based on daily minimum loads to model expected scheduling (decommitment) of Muja C/D (Muja_G5-Muja_G8) and Collie facilities in the pre-optimisation market dispatch model; and
2. Consistent with point one above and historical operational practice the first 95 MW of Muja C/D generation facilities are offered into the balancing market at the market floor price. This provides low cost energy into the balancing market when other Muja units are not online and the opportunity for online facilities to provide LRR capacity which is enabled above 90 MW dispatch level.

5.1 Insights from 2018 AS parameter review

As part of the 2018 AS parameter review, EY undertook a backcasting exercise to demonstrate the mathematical and logical integrity of the 2-4-C® dispatch engine. This exercise also derived detailed offer profiles for each individual WEM facility. The 2018 backcasting exercise demonstrated that modelling of this nature can result in reasonable alignment with historical market outcomes if the model has perfect foresight of market events, power system conditions and if offer profiles were suitably calibrated.

An important lesson learnt from the 2018 backcasting exercise was that it is better to conduct backcasting after the collection of facility assumptions data, as dispatch of facilities is through a heat rate based optimisation algorithm rather than on the basis of historical offer profiles (this approach being required to calculate ancillary services costs). It was also noted that backcasting can lead to a false sense of precision in simulated outcomes. Backcasting to derive offer curves to emulate historical dispatch and pricing outcomes does not take into account future market rule changes, market reforms and other market developments. Furthermore, calibrating offer curves to emulate historical dispatch inherently captures the necessary shifting of capacity into market floor and market cap price offers that reflect reservation of capacity for spinning reserve and load rejection. Such calibration would obviate the primary purpose of the modelling, being to estimate the opportunity cost of providing these services.

In practice, market models do not have perfect foresight of future market events and will inherently require assumptions to be made regarding future demand, generator availability, solar and wind resource, market participant behaviour and more. These assumptions may differ from what transpires in the market and these differences may lead to materially different outcomes.

5.2 Inputs and assumptions for the backcasting and model calibration exercise

Table 6 summarises the input data and sources used in the 2019 AS parameter modelling backcasting and model calibration exercise.

Table 6: Summary of input data used for the backcasting and model calibration exercise

Input data	Source	How input data is used in backcast simulation
Generator list	http://data.wa.aemo.com.au/#facility-scada	To ensure each physical generation facility is modelled.
2018-19 half-hourly demand	http://data.wa.aemo.com.au/#facility-scada	The half-hourly demand trace is the sum of the measured output of the modelled power stations. Generation is dispatched in merit to meet that historical demand in each trading interval.
2018-19 half-hourly generation	http://data.wa.aemo.com.au/#facility-scada Energy generated (MWh)/0.5. This data is the energy sent-out from the power station.	Large-scale wind and solar generators have their availability set based on the half-hourly historical generation levels, which inherently captures historical outages and curtailment.
2018-19 outages	http://data.wa.aemo.com.au/#outages	Historical reported outages (full and partial, planned, forced and consequential) were used directly as half-hourly availability profiles for key generators (Collie, NewGen Kwinana) in the backcasting exercise.
2018-19 transmission loss factors	https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors	Historical loss factors are used in 2-4-C® to adjust the bids before being used in dispatch as they are in the actual market.
2018-19 maximum price and alternative maximum price	https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits	The alternative maximum price is set as the maximum balancing price that can be set in 2-4-C®. The maximum or alternative maximum were used as the highest bid band as appropriate for each generator.
Offer profiles	Information submitted by MPs	Offer profiles for each generator are initially based on SRMC calculations using information provided by MPs to AEMO and EY. These offers will include consideration for minimum stable generation, provision of LFAS clearing quantities, and SRAS contractual obligations.

5.3 Backcasting approach

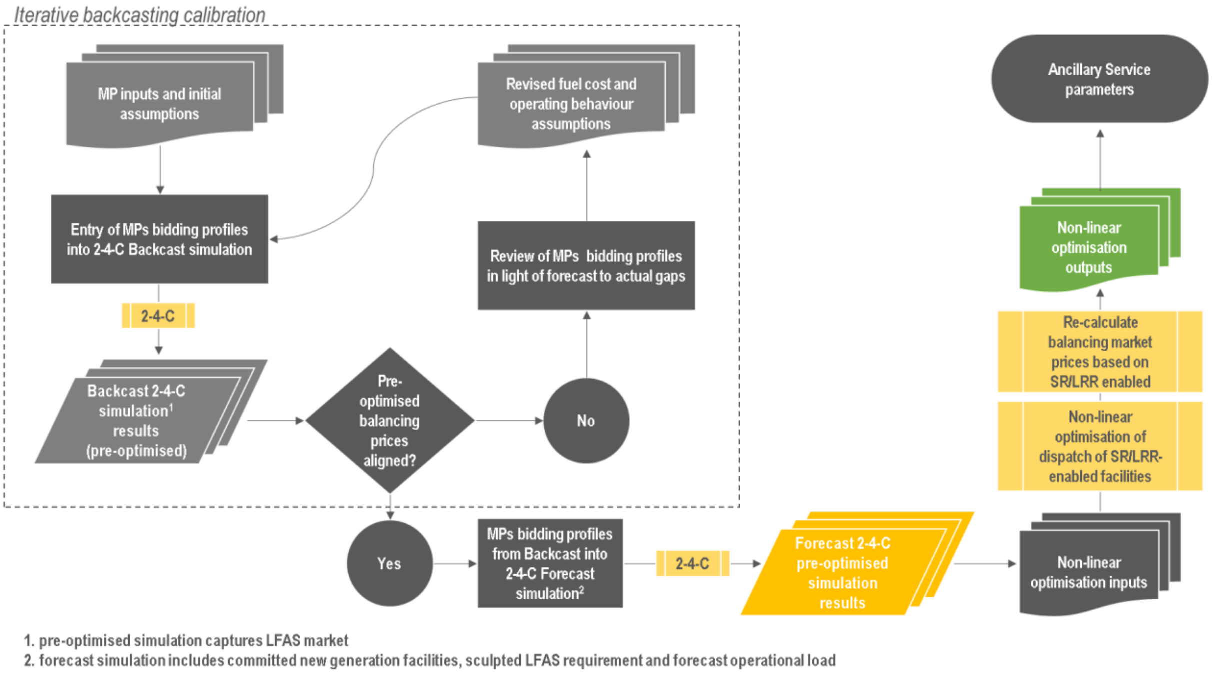
The objective of the backcasting exercise was to calibrate the dispatch and AS optimisation model and to reproduce historical price and dispatch outcomes with a suitable level of alignment.

EY's approach to the backcast can be summarised as follows:

- Set up the dispatch and AS optimisation model to simulate the 2018-19 financial year, using the input data as described earlier
- Use 2018-19 financial year historical data on SWIS demand (input data as described earlier)
- Use 2018-19 financial year historical data to derive availability traces for largest thermal units (input data as described earlier)
- Construct generator offer profiles reflective of short run average cost (SRAC) derived for heat rate applicable to a unit's minimum stable generation level, based on data provided by MP
- Observe the simulated pre-optimisation and post-optimisation pricing and dispatch outcomes in the balancing market and modify the bidding profiles into the balancing market accordingly to achieve a closer match to the actual prices and dispatch in the market
- Iteratively re-simulate 2018-19 and refine the bidding profiles until the price and generation outcomes are satisfactory. Refinements to the offer profiles may involve adjusting cost parameters, operating parameters and/or other inputs assumptions.

A high-level flow-chart to illustrate the backcasting and model calibration exercise is presented in Figure 3.

Figure 3: High-level illustration of the backcasting and model calibration exercise



5.4 Capturing the operational behaviour of generators

In order to capture the observed operational behaviours of certain generators that were expected to have a material impact on the modelling outcomes, the following factors have been included in the backcasting and model calibration exercise:

- Offer minimum stable generation level of coal-fired generators at market floor price
- Offer selected high utilisation gas plant at MFP or market cap price, including:
  - NewGen Kwinana offering minimum stable generation level of 162 MW at market floor price
  - Alinta Pinjarra unit 1 and unit 2, each offering 70 MW at market floor price (noting that these units also offer 20 or 30 MW in the LFAS up and down markets, see Appendix B)
- Apply time-of-day unavailability traces to NewGen Kwinana and Collie to more closely align with the actual dispatch outcomes
- Offer all capacity at the market cap price for Synergy gas fired facilities assigned to ready reserve.

5.5 Analysis of results

EY analysed the backcasting and model calibration outcomes for price and dispatch according to a few different metrics, such as annual averages, duration curves and time-of-day averages.

The relevance of each metric is described in the following:

- **Annual average:** annual average price and generation and total annual generation provide the simplest overview of backcasting outcomes, demonstrating the average accuracy of the modelling throughout the year
- **Peak and off-peak:** given the nature of calculating parameters associated with peak and off-peak periods, specific emphasis is placed on examining average pricing outcomes for peak periods (defined as the trading intervals between 8:00am to 10:00pm) and off-peak periods
- **Duration curves:** a duration curve on price or generation shows how accurately the model is producing the distribution of values. For example, the price duration curve can be used to highlight whether the number of negative prices at different levels is being accurately captured by the model. An accurate price duration curve also indicates an accurate total offer-stack (made up of the offer profiles from each generator)
- **Time-of-day averages:** the price and dispatch of generators often exhibit a pattern in behaviour across the day, due to similar patterns in demand. For example, a generator may routinely operate at a minimum load overnight but produce more energy during the day. Capturing this daily behaviour accurately is another indicator that the modelling is producing outcomes that are in line with physical and commercial behaviour in the system.

5.6 Backcasting and model calibration outcomes

5.6.1 Initial backcasting results

The following section presents the results of the initial backcasting exercise using key input parameters provided by MPs.

Generator dispatch outcomes from the post-optimisation backcast indicated that key baseload thermal plant operated in a manner consistent with actual observed outcomes from the 2018-19 financial year.

Figure 4 and Figure 5 demonstrates modelled dispatch of Collie compared to actual observed operational behaviour.

Figure 6 and Figure 7 demonstrate modelled dispatch of NewGen Kwinana compared to actual observed operational behaviour.

Figure 4: Modelled dispatch of Collie and actual observed operational behaviour: generation duration curve

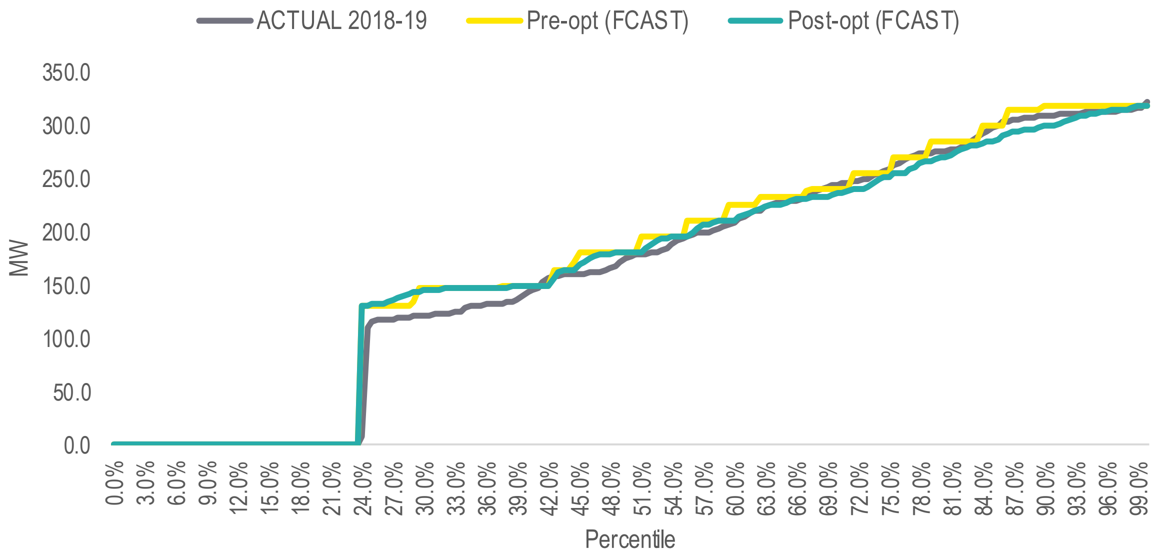


Figure 5: Modelled dispatch of Collie and actual observed operational behaviour: average time-of-day[19] dispatch

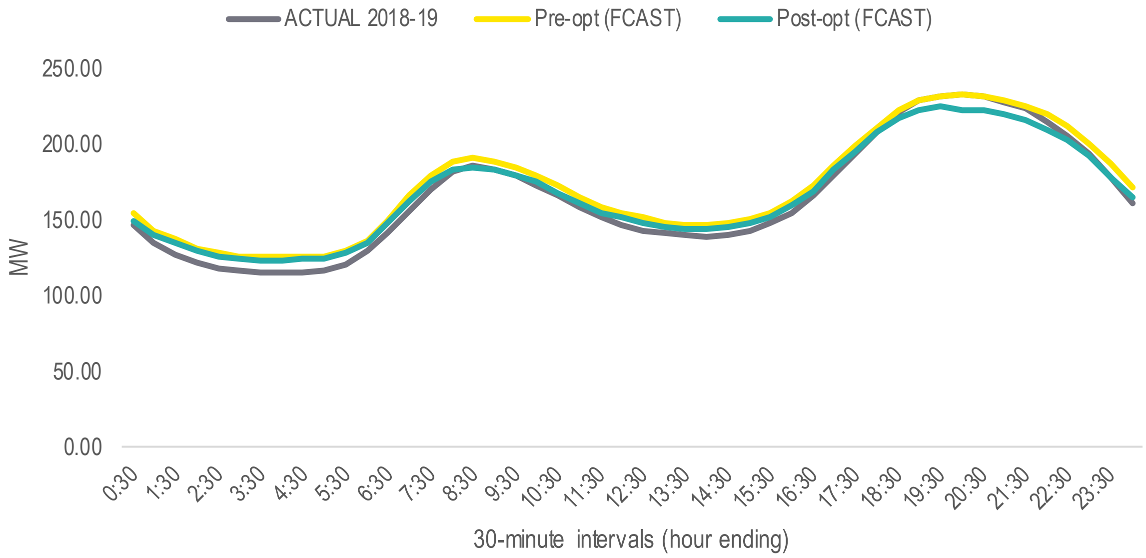
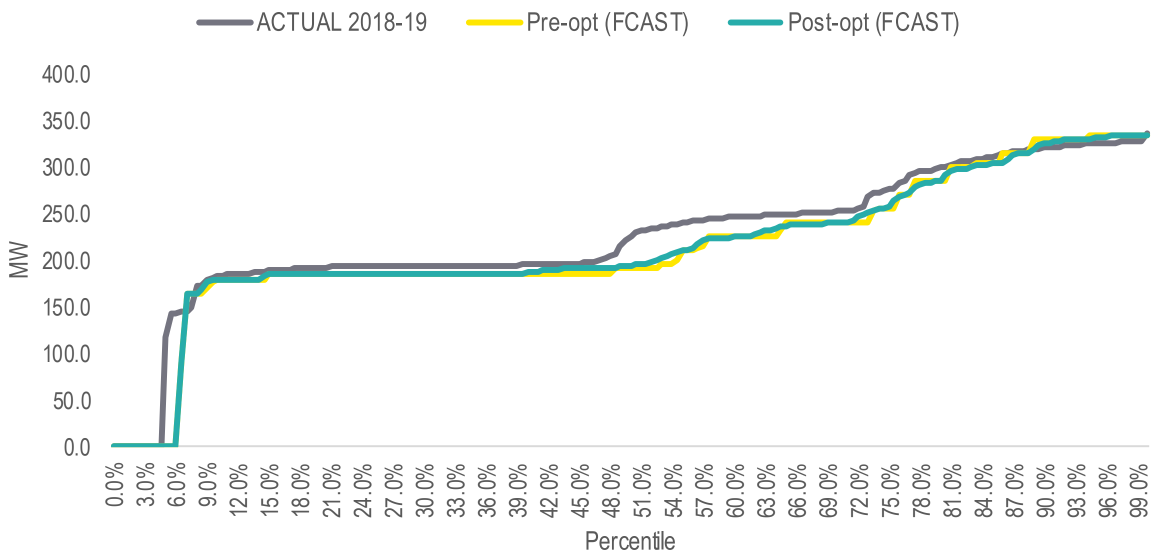
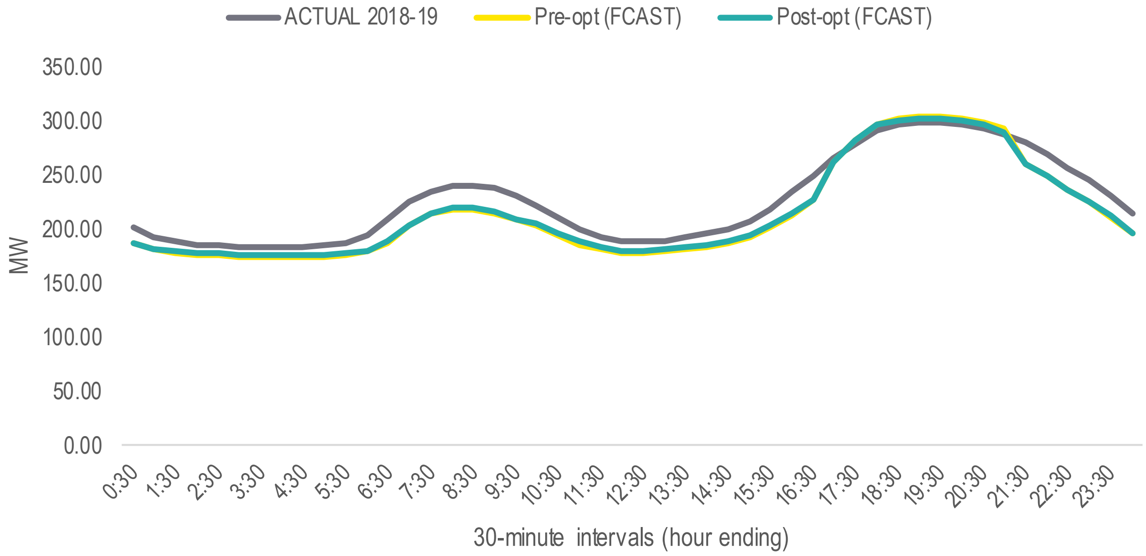


Figure 6: Modelled dispatch of NewGen Kwinana and actual observed operational behaviour: generation duration curve



[19] For all graphs in this report, average time-of-day calculations include intervals with zero MW values.

Figure 7: Modelled dispatch of NewGen Kwinana and actual observed operational behaviour: time-of-day dispatch



While the modelled dispatch outcomes were well aligned with historical dispatch observations, the balancing price outcome was materially higher than historical outcomes. Figure 8, Figure 9 and Figure 10 show the modelled time-of-day average prices, annual average volume-weighted prices and price duration curves from the preliminary model against actual 2018-19 values, for modelling completed with unadjusted fuel cost assumptions received from MPs.

It can be seen from Figure 8 that the modelled average balancing prices are systematically higher at all times of the day when compared to actual prices (~$10/MWh to ~$27/MWh). Figure 9 shows that annual volume-weighted average balancing prices are inflated by ~$20/MWh as compared to actual 2018-19 prices. The price duration curves in Figure 10 suggests that the inflated prices appear to be structural at nearly all levels of the merit order.

Figure 8: Time-of-day SWIS prices modelled in the 2018-19 backcast with unadjusted MP cost assumptions and Synergy gas price of $6.50/GJ

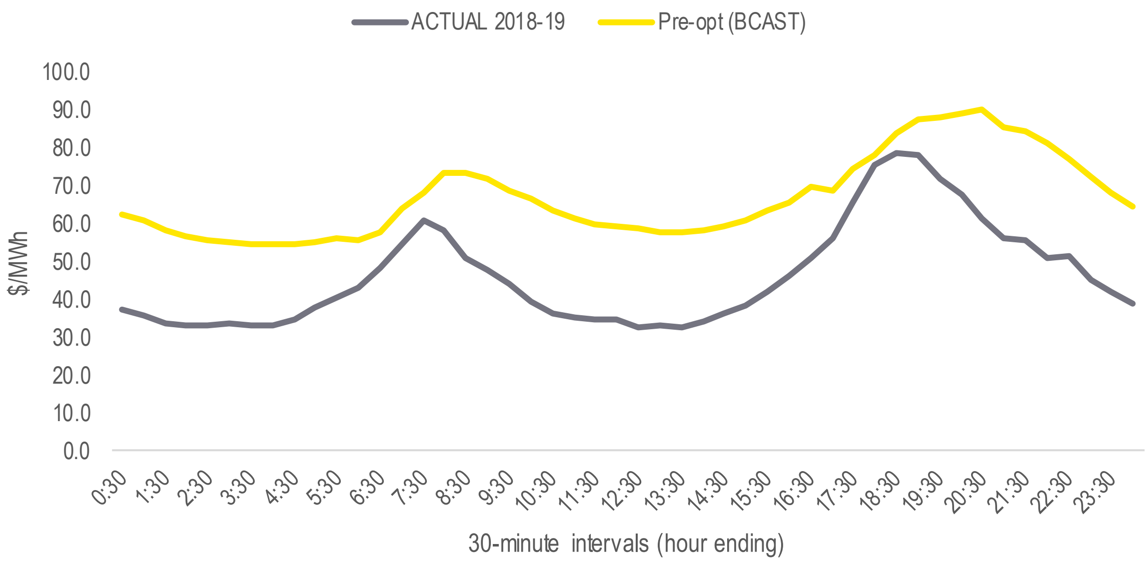


Figure 9: Volume-weighted SWIS prices modelled in the 2018-19 backcast with unadjusted MP cost assumptions and Synergy gas price of $6.50/GJ

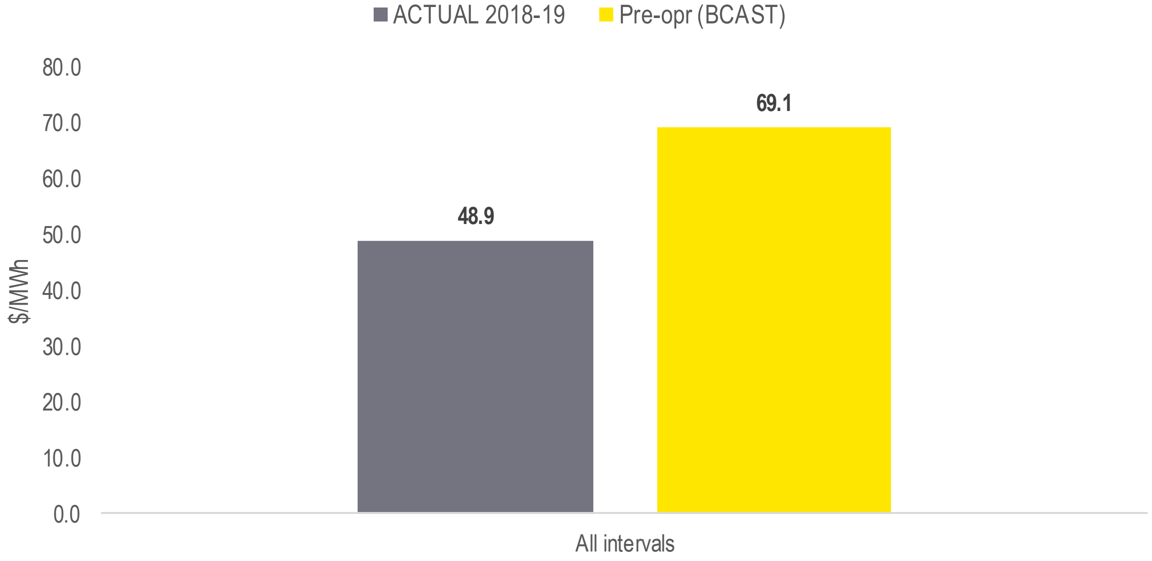
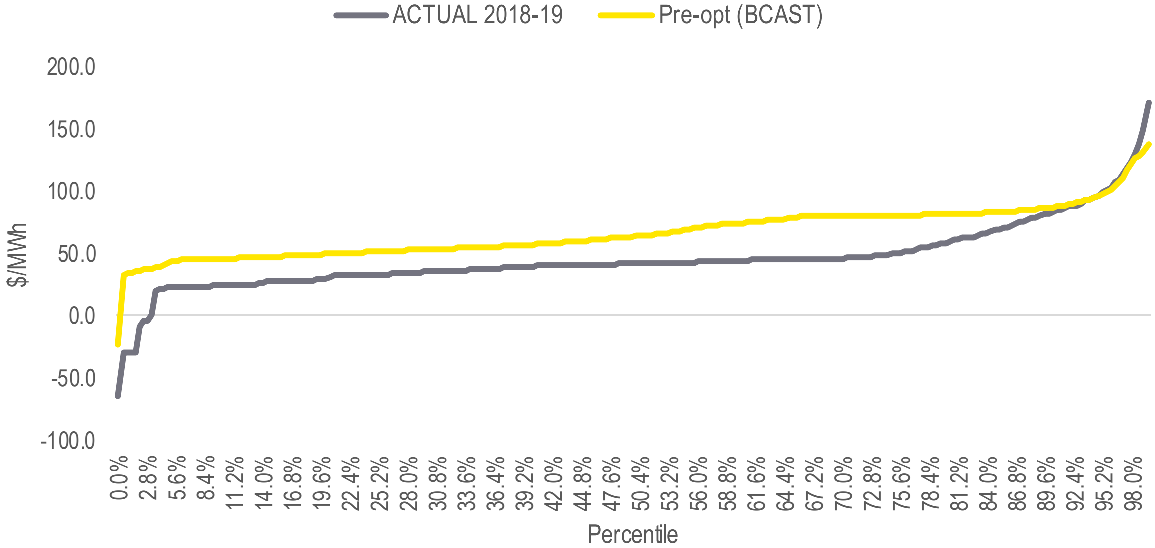


Figure 10: SWIS price duration curves modelled in the 2018-19 backcast with unadjusted MP cost assumptions and Synergy gas price of $6.50/GJ



5.6.2 Backcasting calibration

One possible factor contributing to the higher modelled balancing prices as shown above may be that the initial assumed Synergy gas price of $6.50/GJ is too high. Another possible factor could be that the cost assumptions at the bottom of the merit order (i.e. from baseload coal-fired and IPP gas generators) are too high relative to Synergy's assumed gas price.

Table 7 provides a summary of the publicly available data on WA gas prices, showing a range in prices from $2.60/GJ to $5.00/GJ. While it is acknowledged that Synergy may have long-term gas contracts with costs that are higher than the range of prices listed in Table 7, the Synergy gas price in the model has been adjusted down within this range to better align the modelled balancing prices with actual historical prices.

Table 7: Summary of publicly available data on gas prices in Western Australia

Gas pricing data	Comment	Source
~$4.6/GJ to ~$5.0/GJ	Average actual domestic gas prices 2015 to 2017	WA GSOO 2018 https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities
~$2.6/GJ to ~$2.8/GJ	Weighted average production cost 2018 to 2021	WA GSOO 2018 https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities
$3.9/GJ	Average WA spot gas price (Q1 2015 to Q3 2018)	WA GSOO 2018 https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities
$4.7/GJ	Historical domestic gas contract prices (Q1 2015 to Q2 2018)	WA GSOO 2018 https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities
~$3.5/GJ	Short-run gas price projection (1 April 2019 to 30 June 2020)	2019-20 Energy price limits review final report (public) https://www.erawa.com.au/cproot/20601/2/Energy-Price-Limits-proposal-201920.PDF

Figure 11 and Figure 12 show the modelled time-of-day average prices and price duration curves against actual 2018-19 values, modelled with the following inputs:

- A revised (decreased) Synergy gas price of $3.50/GJ [20]
- Coal fuel cost reduced by 40% for Muja, Collie and Bluewaters[21]
- Gas fuel cost reduced by 40% for Newgen Kwinana and Alinta Pinjarra[22].

With these adjustments, the resulting post-optimisation time-of-day average prices and price duration curves more closely align with the actual 2018-19 prices, although the evening peak balancing prices arising from the model are higher than actual prices.

[20] The modelled $3.50/GJ price was derived during the backcasting and model calibration process as described in section 5 and was not confidential information provided by Synergy

[21] The modelled coal prices were derived during the backcasting and model calibration process as described in section 5

[22] The modelled gas fuel prices were derived during the backcasting and model calibration process as described in section 5

Figure 11: Time-of-day SWIS prices modelled in the 2018-19 backcast with modified MP cost assumptions and Synergy gas price of $3.50/GJ

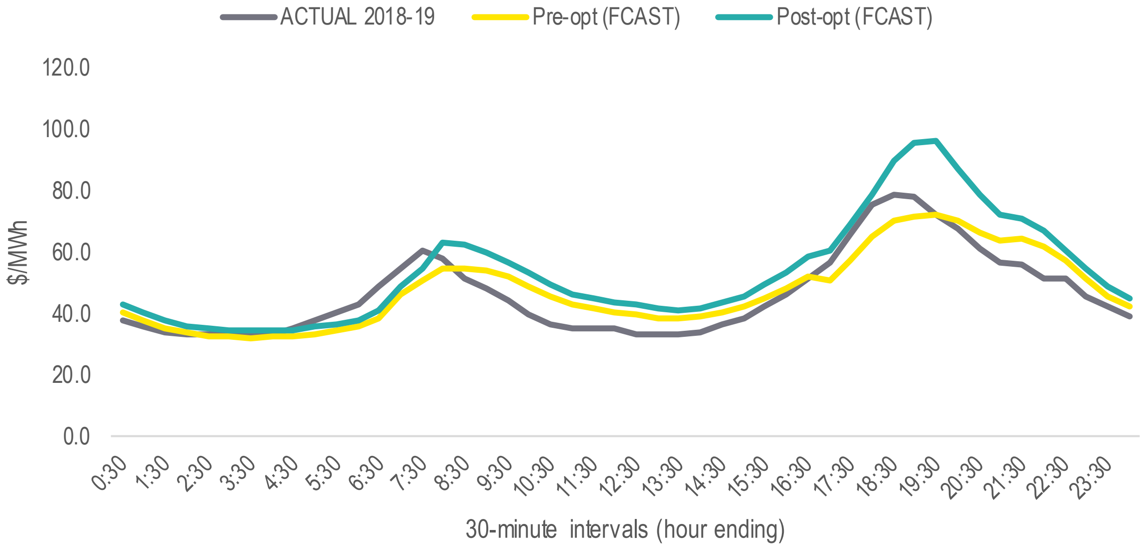
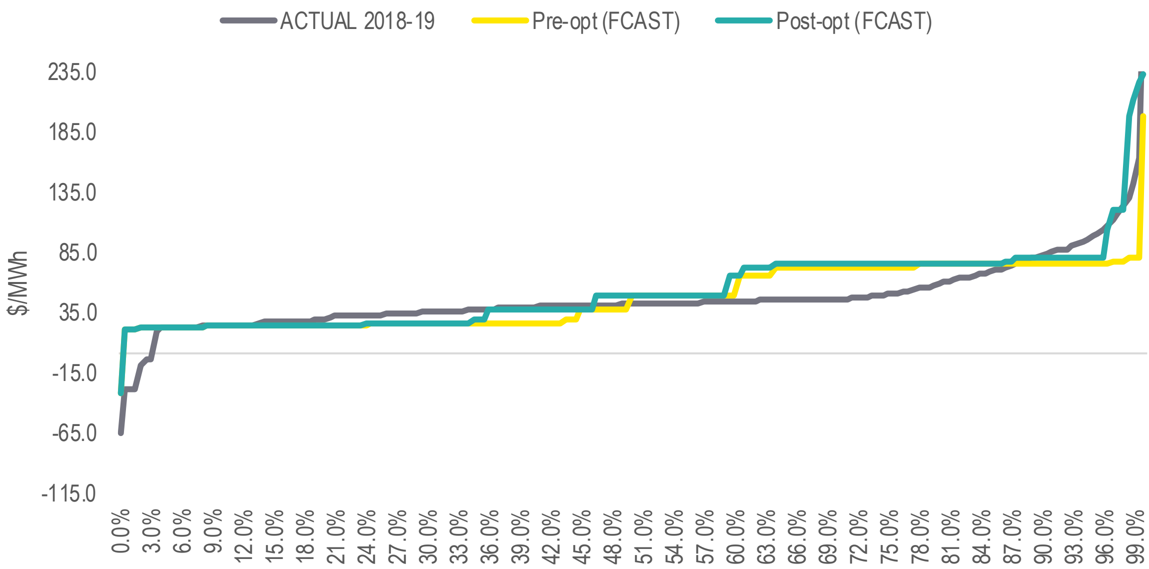


Figure 12: SWIS price duration curves modelled in the 2018-19 backcast with modified MP cost assumptions and Synergy gas price of $3.5/GJ



Detailed per-facility and per-interval data on the backcasting exercise has been provided in a separate Excel spreadsheet for detailed review by AEMO and the ERA.

5.7 Forward-looking baseline model outcomes

The WEM dispatch and optimisation model, using the modified MP cost assumptions and Synergy gas price of $3.50/GJ[22] described in the previous section, was applied for the forecast 2020-21 financial year, with the assumptions in Appendix A incorporated.

Figure 13 and Figure 14 show the modelled time-of-day average prices and price duration curves for the 2020-21 forecast against actual 2018-19 prices. It can be seen that balancing prices in 2020-21 are expected to be significantly lower than in 2018-19 (approximately $19/MWh lower on a volume-weighted basis), due to the entry of over 500 MW of new renewable power stations (see Appendix A.6).

Figure 13: Time-of-day SWIS prices modelled in the forward-looking baseline model compared against 2018-19 actuals

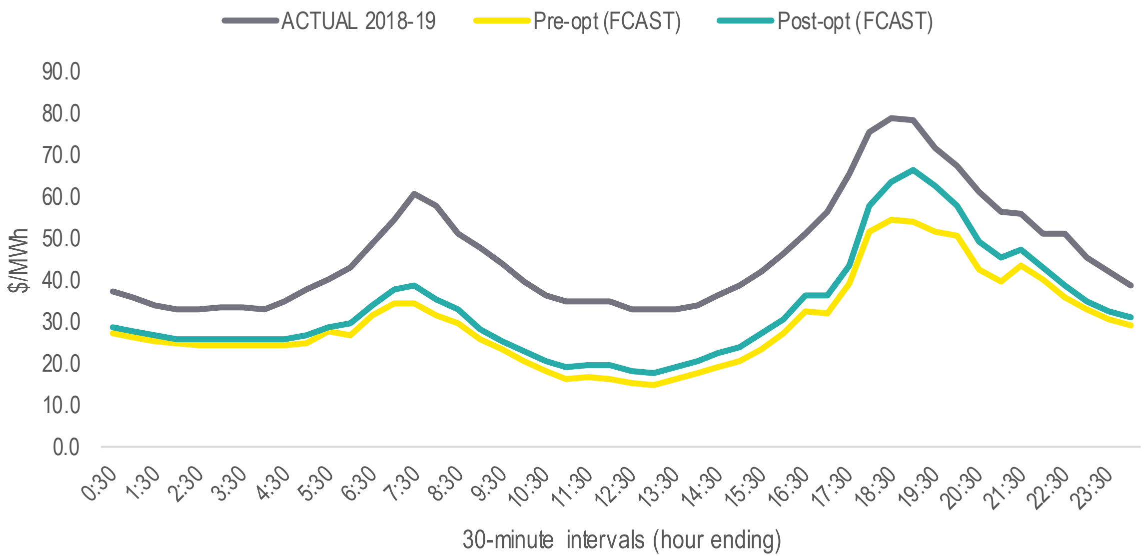
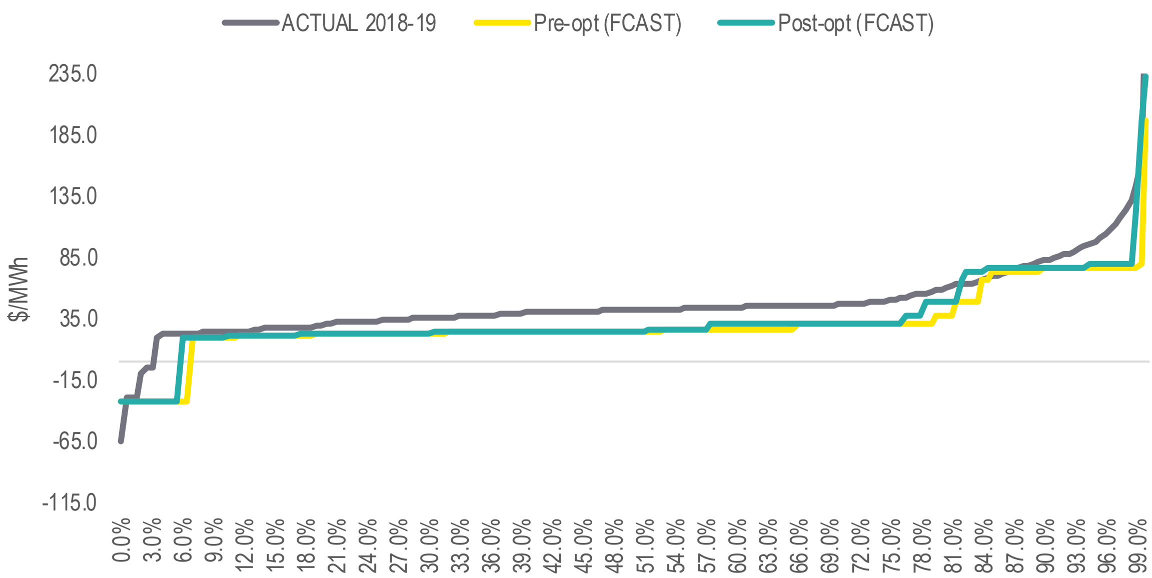


Figure 14: Average SWIS price modelled in the forward-looking baseline model compared against 2018-19 actuals



5.8 Summary of the backcasting and model calibration exercise

The backcasting and model calibration exercise described in this section 5 was performed by EY to demonstrate and ensure that:

- Any significant variances or material errors observed in the model outcomes relative to actual data were identified and addressed by AEMO
- Model calibration has improved the outputs produced by the model
- The AS optimisation model used in the 2019 AS parameters modelling is fit for purpose and does not provide significant modelling errors.

For original fuel cost assumptions provided by MP, the performed backcasting and model calibration exercises have shown that:

- ► The modelled average balancing prices are systematically higher at all times of the day when compared to actual prices (~$10/MWh to ~$27/MWh)
- ► The annual volume-weighted average balancing prices are inflated by ~$20/MWh as compared to actual 2018-19 prices.

The above observations justified applying the following modifications of the original fuel cost assumptions provided by MPs:

- ► A revised (decreased) Synergy gas price of $3.50/GJ[20]
- ► Coal fuel cost reduced by 40% for Muja, Collie and Bluewaters facilities[21]
- ► Load-independent variable O&M was set to zero for Cockburn, Kwinana GTs, Muja, and Collie.
- ► Gas fuel cost reduced by 40% for Newgen Kwinana and Alinta Pinjarra.

With these adjustments, the resulting post-optimisation time-of-day average prices and price duration curves more closely aligned with the actual 2018-19 prices.

In order to capture the observed operational behaviours of certain generators (and to address recommendations made in the ERA 2019 Decision), the following factors have been included in the backcasting and model calibration exercise:

- ► Offer minimum stable generation level of coal-fired generators at market floor price
- ► Offer a proportion of selected high utilisation gas plant at market floor price, including:
    - ► NewGen Kwinana offering minimum stable generation level of 162 MW at MFP
    - ► Alinta Pinjarra unit 1 and unit 2, each offering 70 MW at market floor price (noting that these units also offer 20 or 30 MW in the LFAS up and down markets, see Appendix B)
- ► Apply time-of-day unavailability traces to NewGen Kwinana and Collie to more closely align with the actual dispatch outcomes
- ► Offer all capacity at the market cap price for Synergy gas fired facilities assigned to ready reserve.

The above modified fuel cost assumptions and operational behaviours resulting from the backcasting and model calibration exercises were used to set up the dispatch and AS optimisation model used in the 2019 AS parameter modelling.

6. SRAS and LRR modelling methodology steps

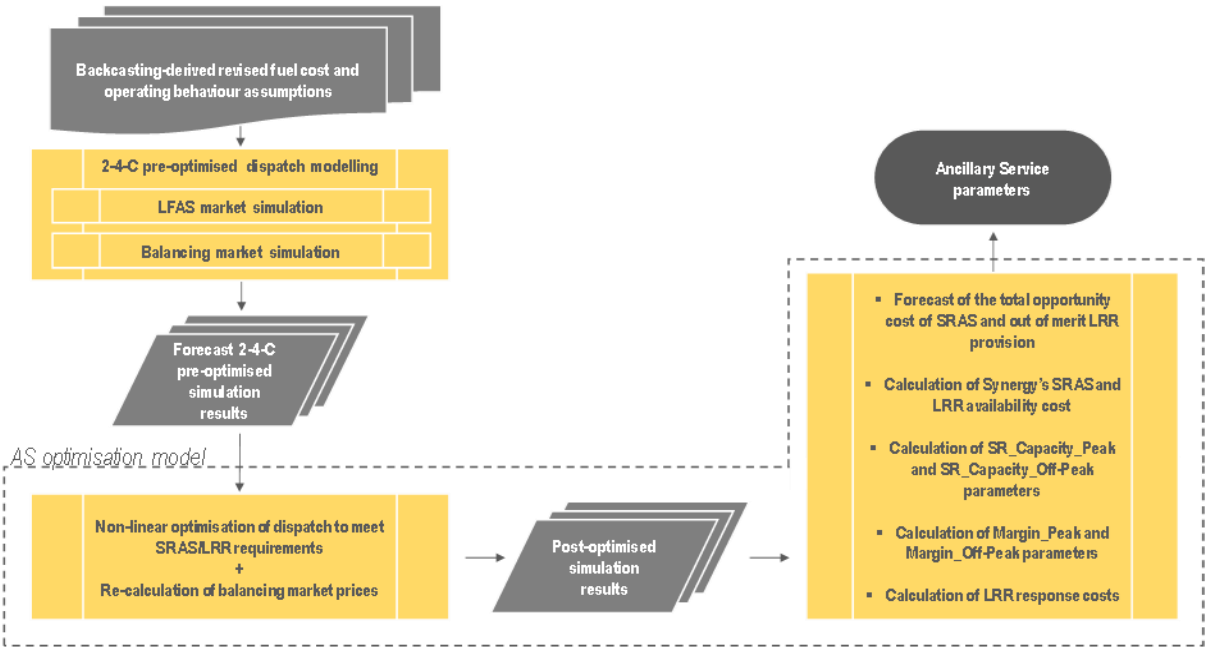
In light of Sections 2.5 and 2.6 , and the requirements of the WEM Rules more generally, our proposed detailed method for calculating ancillary services parameters includes the steps listed below.

1. Modelling of generation outages and the least-cost mix of LFAS providers
2. Preliminary dispatch model (pre-optimisation)
3. Calculation of the dynamic SRAS requirement and the LRR requirement
4. Non-linear constrained optimisation (minimisation) of costs, including:
    - The opportunity cost of providing SRAS
    - The direct cost of out of merit[23] provision of SRAS and LRR

    subject to the SRAS and LRR requirement being met.
5. Balancing price modelling
6. Forecast of the total opportunity cost of SRAS and out of merit LRR provision
7. Calculation of Synergy's SRAS and LRR availability cost
8. Calculation of SR_Capacity_Peak and SR_Capacity_Off-Peak parameters
9. Calculation of Margin_Peak and Margin_Off-Peak parameters
10. Calculation of LRR response costs.

A high-level flow-chart to illustrate the AS parameters modelling process is presented in Figure 15.

Figure 15: High-level overview of the AS parameters modelling process



[23] For the purposes of this report and calculating the AS parameters, the term 'out of merit' refers to out of merit dispatch of the units within Synergy's balancing portfolio offer quantities. That is when a more expensive Synergy unit replaces the generation of another less expensive Synergy unit, and the cost exceeds the balancing price. Under the WEM Rules the substitution of more expensive generation for less expensive generation within the balancing portfolio is not compensated by constrained generation payment mechanism outlined in clause 6.17 of the WEM Rules.

Detailed descriptions of the above steps are provided in the following subsections.

6.1 Modelling of the least-cost mix of LFAS providers

The primary reason for modelling the LFAS markets is to simulate the impact of LFAS market outcomes on the balancing market. To ensure that cleared LFAS quantities are made available in the balancing market they must be reflected in balancing market offers as follows:

- LFAS up providers must, in accordance with clause 7A.2.9 and 7A.3.5 of the WEM Rules:
    - Offer their minimum generation level into the balancing market at the floor price; and
    - Offer at the ceiling price balancing quantities for its cleared LFAS up quantity.
- LFAS down providers must offer at the price floor a quantity equal to the sum of their minimum generation level and the cleared LFAS down quantity, in accordance with clause 7A.2.9 and 7A.3.5 of the WEM Rules.

The outcomes of the LFAS modelling will pass through constraints that ensure these requirements are reflected in the dispatch and generation outage modelling, detailed in the following sections. Monte Carlo iterations of forced outage simulations will be conducted at this stage, with each forced outage iteration carried through to subsequent modelling steps. This will be applied to produce multiple time series of unplanned generation outage events. Probabilistic modelling of the generator outages and dispatch levels will provide an input to determine the required levels of SRAS and LRR in each trading interval.

The LFAS modelling will apply merit orders for the provision of LFAS up and LFAS down derived from recent bidding behaviour in the market, assumptions about possible new entrant LFAS providers and the heat rate characteristics of LFAS capable Synergy plant. The 'demand' for LFAS in each trading interval will be equated to AEMO's sculpted LFAS requirement.

As per section 3.2, AEMO has calculated that the LFAS requirement to be used for modelling will be:

- 116 MW from 5.30 AM to 7.30 PM
- 70 MW from 7.30 PM to 5.30 AM.

The optimisation problem for LFAS up requirement in each trading interval t of a financial year, $t = 1,2,3,\dots,T,$ T being the number of trading intervals in the year, is given by Equations (1) and (2) below:

$$\text{minimise} \qquad \sum_{i\in\Lambda} \rho_i \theta_i \tag{1}$$

$$\text{subject to} \qquad \sum_{i\in\Lambda} \theta_i \geq \delta, \qquad \delta = \begin{cases} 116 & \text{between 5.30 AM to 7.30 PM} \\ 70 & \text{otherwise} \end{cases} \tag{2}$$

where Λ denotes the set of plants that are able to provide LFAS up, ρ_i, $\{\rho_i \geq 0\}$, denotes the LFAS up price offer of generation unit i, and the plant's LFAS commitment is denoted θ_i, $\{0 \leq \theta_i \leq \lambda_i\}$, where λ_i denotes the assumed maximum LFAS capability of plant i. For the purposes of notational clarity t subscripts have been suppressed in Equations (1) and (2). An equivalent approach is taken for LFAS down.

6.2 Preliminary dispatch model

This step will provide a preliminary view of the dispatch outcome for the WEM on the basis of short-run marginal cost balancing merit order profiles.

Consistent with Section 3.3, the SRMC curves of generators will be adjusted to model the expected marginal cost of estimated SRAS payments under the 'full runway' method.

Specific departures exist for generator units providing AS:

- As discussed in the preceding subsection, generators that provide LFAS are offered at the price caps to ensure they are dispatched accordingly. IPP facilities that provide LFAS offer their LFAS quantity based on a historical offer profile[24]
- Contracted SRAS providers offer their SRAS capacity at the ceiling price and minimum generation at the floor price, effectively reserving a portion of their capacity for SRAS
- A de-commitment schedule has been applied for Muja C/D and Collie facilities as described in Section 5 above.

The dispatch outcomes will provide visibility over the balancing merit order and therefore the expected level of output that generation units would sell into the balancing market if they were not providing SRAS and LRR. This step also provides an estimate of the balancing price for each trading interval based upon the short run marginal cost bidding behaviour of MPs.

6.3 Calculation of the dynamic SRAS requirement and the LRR requirement

AEMO has assumed that the LRR requirement for 2020-21 will be based on the dynamic LRR requirement, discussed in Section 3.4.

The outputs of steps detailed in sections 6.1 and 6.2 will be used to calculate the SRAS requirement in each trading interval, in line with clause 3.10.2 of the WEM Rules and the levels approved in the ERA 2019 Decision (see Table 2).

For the purposes of modelling, clauses 3.10.2(a) and 3.10.2(b) of the WEM Rules form the basis used to define the dynamic SRAS requirement in trading interval t. In line with Section 3.1, the impact of the largest network contingency event that would result in the largest loss of generation has also been accounted for in the modelling. Let:

$$Y \geq 0.7G \tag{3}$$

where $G\ \{G > 0\}$, is the greater of the total output, including parasitic load, of the synchronised generation unit that is generating the highest total output in trading interval t, or the net supply from Yandin Wind Farm plus Warradarge Wind Farm minus the load supported by the NT NBT TST 330 kV line. The dynamic SRAS requirement net of LFAS capacity contributing to SRAS in trading interval t, S, is then given by:

$$S = Y - U + H + \Gamma \tag{4}$$

where:

- S is the dynamic SRAS requirement net of LFAS capacity contributing to SRAS in trading interval t

[24] It is noted that out of merit generation costs will be influenced by the availability of generators. The probabilistic nature of this modelling is captured by using Monte Carlo simulations with results average across all iterations of simulations. AEMO has also advised of periods where market participants other than Synergy are cleared in the LFAS down market but presently have technical restrictions to provide LRR. This scenario may contribute to additional out of merit generation costs associated with meeting the LRR standard and has been considered in cost calculations.

- U is the MW capacity necessary to cover the requirement for providing LFAS up for trading interval t
- H is the MW quantity of LFAS up capacity that does not contribute to meeting the SRAS requirement
- Γ is LFAS up consumed, generated from Monte Carlo simulations based on a parametric distribution provided by AEMO.

As discussed in section 1.2, the impact of LFAS consumed on LFAS-capable units' contributions to the SRAS requirement has been introduced in response to Synergy's submission to this year's AS parameters review.

In line with Section 3.4, EY will model the LRR requirement based on a dynamically set requirement. The formula for calculation of the dynamic LRR requirement provided by AEMO is as follows:

$$LRRreq = \min(120, \max(BGM, EGF, 70)) - \max\left(30, \frac{3}{200}(SystemTotal - \max(BGM, EGF))\right)$$

where:

- $LRRreq$ is the dynamic LRR requirement
- BGM is the Boddington Gold Mine load in MW
- EGF is the Eastern Goldfields load in MW
- $SystemTotal$ is the total as-generated (gross) output of all market generators in MW.

6.4 Non-linear optimisation of the SRAS and LRR requirement

This step will solve for the minimum cost mix of all generation units that are able to provide SRAS in each trading interval of the modelling period, subject to LRR constraints. Before the optimisation process is described in detail (Section 6.4.3), the methodology for calculation of the opportunity cost of providing SRAS and the cost of providing LRR is described in Section 6.4.1 and Section 6.4.2 respectively.

6.4.1 The opportunity cost of providing SRAS

As noted in Section 2.5, the cost associated with provision of the SRAS (the opportunity cost of providing SRAS) is equivalent to the net revenue forgone in the balancing market.

The total opportunity cost, $C_i(s_i)$, for in-merit generation unit i providing quantity s_i of SRAS in each trading interval, will be found by solving the definite integral in Equation (5).

$$C_i(s_i) = \int_{J_i - s_i}^{Q_i} \left(p_i - f_i(x_i)\right) dx_i \tag{5}$$

where:

- s_i is the quantity of SRAS provided by generating unit i, $\{s_i \geq 0\}$
- $C_i(s_i)$ is the opportunity cost of providing SRAS, equivalent to the net revenue forgone in the balancing market
- p_i is the balancing market price
- $f_i(x_i)$ denotes the marginal cost of generation of unit i as a function of its output x_i, $\{x_i \geq 0\}$

- J_i denotes the maximum rated capacity of the unit, $\{J_i \geq 0\}$
- Q_i is the output that the unit would sell into the balancing market if it were not providing SRAS, $\{J_i \geq Q_i \geq 0\}$.

Estimation of $f_i(x_i)$ will entail fitting a polynomial function to heat rate data for each generation unit, then multiplying this function by an assumed per MW half hourly cost that reflects the opportunity cost of fuel plus non-fuel variable operating costs and an estimate of the marginal cost associated with the 'full runway' cost allocation of SRAS payments to generators.

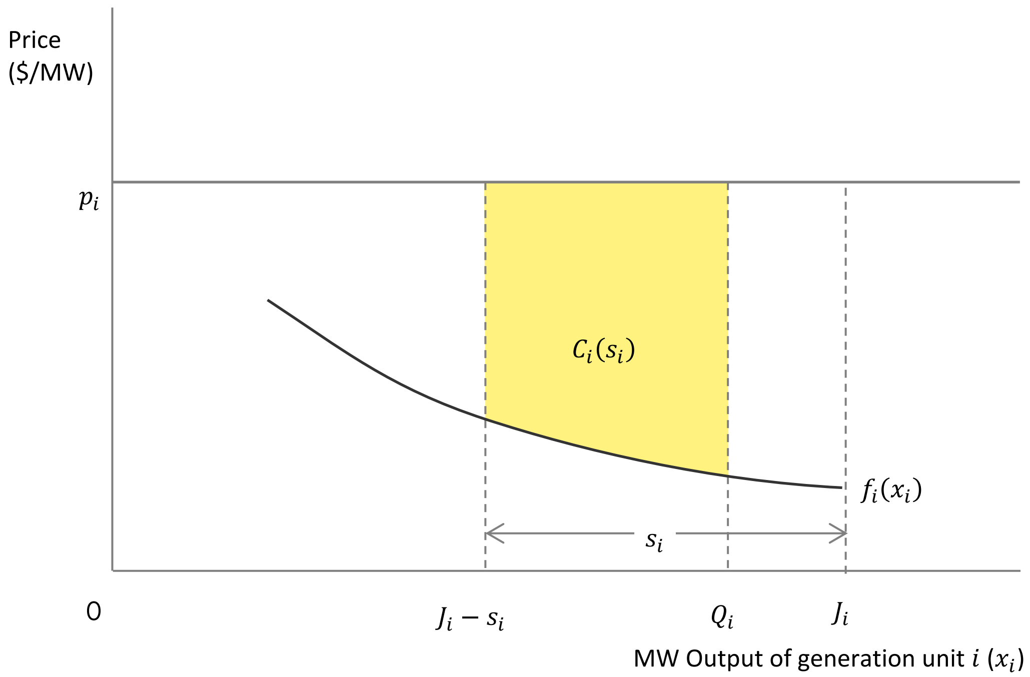
The value of Q_i can be no greater than a generation unit's maximum rated capacity, J_i, and may be further constrained by any out of merit output offered into the balancing market. This reflects the concept that the opportunity cost of any reserve capacity that would not otherwise be dispatched in the WEM is equal to zero.

The method for calculating the opportunity cost of SRAS for an in-merit generation unit is described graphically in Figure 16 below, which is an adaptation of Figure A5 provided in Appendix 2 of the ERA 2018 Determination.

SRAS units that are required to be operated out of merit to provide SRAS or LRR will include fixed heat rate costs in the calculation of opportunity cost.

The number of times each unit is required to start-up will be recorded in both the pre-optimisation and post-optimisation modelling phases, as well as the reason for out of merit start-up either being due to the need to meet SRAS or LRR requirements or both. The difference between the number of pre- and post- optimisation start-ups will be attributed to the trading interval in which a unit was started-up to meet SRAS or LRR. Allocation of start-up costs to SRAS and LRR allocation costs will be in line with their relative shares of total out of merit start-ups.

Figure 16: The opportunity cost of a generation unit's provision of spinning reserve



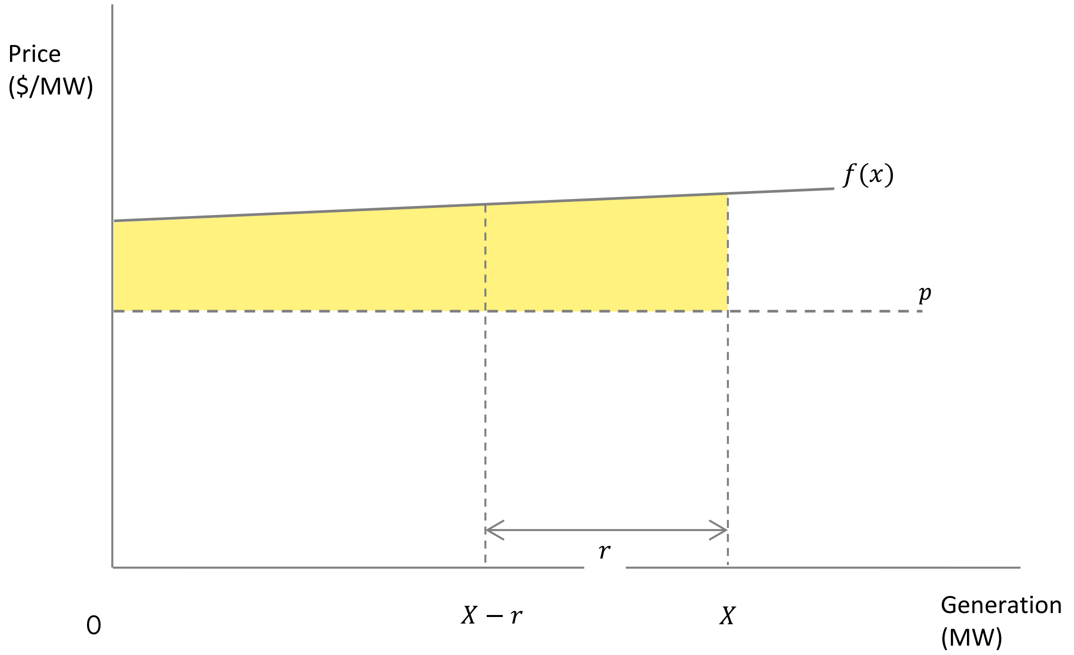
6.4.2 The opportunity cost of dispatching SRAS and LRR out of merit

For trading intervals that require generation to be dispatched out of merit to meet the SRAS and/or LRR requirements, the cost incurred by the generator being committed is calculated as the fixed heat rate costs, start-up cost, the costs associated with any energy production plus the estimated marginal cost of payments under the 'full runway' method. These costs are offset by balancing revenues received by the unit.

The cost associated with producing energy is based on facility cost data provided by Synergy. As noted in section 5, certain adjustments to Synergy's and IPPs' fuel costs were made to ensure input validation, and to ensure that the model is fit for purpose and does not produce material errors. AEMO has provided information with regards to the order in which units are to be dispatched. This aligns with the Synergy dispatch guideline and is ordered from cheapest available plant to most expensive.

The calculation for the variable component of out of merit operation is illustrated in Figure 17 for the case where a single unit is required to provide LRR and/or SRAS capacity in a trading interval.[25] Fixed heat rate cost and start-up are also included, but not shown in the figure. $f(x)$ denotes the heat-rate based plus variable O&M marginal cost function (in $/MW) of the unit, which includes consideration of variable fuel cost, variable operating cost and variable spinning reserve payments. p represents the balancing price (in $/MW) for the trading interval. X is the output of needed from the generator during the trading interval, and r is the quantity (in MW) above the unit's minimum generation level that gives the optimal combination of LRR and SRAS. $X - r$ is therefore equal to the unit's minimum generation level.

Figure 17: Illustrative diagram of the calculation of variable costs for out of merit provision of SRAS or LRR capacity



[25] Marginal heat rate curves are illustrative and need not be upwards sloping.

The fact that the marginal cost function illustrated in Figure 17 is above the balancing price defines the case as being an out of merit dispatch. The unit is also clearly providing LRR, as it would not be optimal for an out of merit unit that is only required to meet SRAS requirements to operate above minimum generation levels. Whenever the optimisation process (described in Section 6.4.3 below) dispatches a unit to provide SRAS out of merit, but the optimisation also causes that unit to operate above its minimum generation level, this will be considered a sign that the unit is also providing LRR. In such a case, the out of merit costs will be allocated between SRAS and LRR. More specifically, the part of the yellow area between zero and the unit's minimum stable generation level $X - r$ will be allocated to SRAS costs, and the part of the yellow area between the unit's minimum stable generation level and the output needed from the generator X in Figure 17 will be allocated to the LRR availability costs. A proportion of the fixed heat rate and start-up components equal to $(X - r)/X$ will be allocated to the SRAS availability costs and the remainder of these costs, if any will be allocated to LRR costs.

LRR is currently provided by generators in the Synergy balancing portfolio only. The WEM Rules also allow for non-Synergy generators to provide this service but no contracts have been entered into to date. The cost calculation is therefore centred on the cost to Synergy generators in providing LRR.

Synergy generators that provide LRR are not required to be enabled to provide this service,[26] but do so by being online and having an output in the correct range as a by-product of being dispatched in the balancing market and for other ancillary services. That is, by providing energy into the balancing market or by being enabled for other ancillary services, generators will innately provide reserves for load rejection, if the generator is technically capable of doing so within the response times specified in the WEM Rules.[27]

Synergy is required to offer quantities of facilities providing LRR at the minimum Short Term Energy Market (STEM) price to ensure these facilities will always be dispatched as per clause 7A.2.9(c)i of the WEM Rules. As such facilities within the balancing portfolio may be compensated at a balancing price (or LFAS price) below their SRMC to meet the LRR requirement.

The total availability cost for out of merit units required to provide either LRR or SRAS (or both) in a year is the summation across all trading intervals for that year. Those costs will be allocated between LRR and SRAS according to an allocation rule to be determined by AEMO. AEMO has indicated the following allocation principles may apply:

- When a unit is operating out of merit to provide SRAS only in a trading interval, then all the associated out of merit costs are allocated to SRAS only
- When a unit is operating out of merit to provide LRR only in a trading interval, then all the associated out of merit costs are allocated to LRR only
- When a unit is operating out of merit to provide both LRR and SRAS, then:
    - Allocate the net out of merit operating costs incurred up to the unit's minimum generation level to SRAS and the remainder to LRR, and
    - Allocate load independent fixed and start-up costs in a proportionate share, with the SRAS share being equal to the unit's minimum stable generation level divided by its output and the remainder allocated to LRAS (i.e. load independent fixed and start-up costs are fully allocated to SRAS only if the unit is providing no load rejection).

When a unit is committed out of merit to provide SRAS, and in doing so also contributes to alleviating any LRR shortfall in that interval, then the costs of operating the unit above its minimum

[26] See Section 2.4 of Ancillary Service Report for the WEM 2018-19, June 2018, AEMO. Available here: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

[27] Clause 3.9.7 of the Rules requires that the relevant facility can either respond appropriately within 6 seconds and sustain or exceed the required response for at least 6 minutes, or respond appropriately within 60 seconds and sustain or exceed the required response for at least 60 minutes, for any individual contingency event.

generation level are attributed to LRR and the costs of operating the unit at minimum generation are attributed to SRAS. Therefore, EY considers it reasonable to attribute these costs on a load proportionate basis between SRAS and LRR. If a unit is operated out of merit in an interval in which the SRAS requirement has been met by in-merit units, then all that unit's out of merit costs are allocated to LRR.

The main input into the calculation of the 'L' parameter in the Cost_LR proposal equates the total availability cost for out of merit units allocated to LRR. This is proposed to be given by:

$$L = \sum_{t=1}^{T} \sum_{i=1}^{N} C_i(x)\eta_i w_i, \tag{6}$$

$$C_i(x) = B_t + \int_0^{X_i} (f_i(x) - p)\, dx,$$

$$w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases}$$

where:

- L is the availability cost attributed to LRR
- T is the number of trading intervals in the year
- N is the number of generation units in the market
- B_t denotes the fixed heat rate costs (in $) incurred in trading interval t
- $f_i(x)$ denotes the heat-rate based plus variable O&M marginal cost function (in $/MWh) of the unit, which includes consideration of fuel and operating costs
- $C_i(x)$ denotes the total net operating cost of the unit incurred in trading interval t
- p is the balancing price (in $/MWh) for trading interval t
- X_i is the output of generator i needed to contribute to the LRR requirement during trading interval t
- η_i, $\{0 \leq \eta_i \leq 1\}$ applies a cost allocation rule, where $\eta_i = 1$ if unit i is operated out of merit to provide LRR but not SRAS, $\eta_i = 0$ if the unit is not operated out of merit or if it is operated out of merit to provide SRAS only, and $0 < \eta_i < 1$ if the unit is operated out of merit to provide both SRAS and LRR. The allocation rule that defines η_i will be specified by AEMO. The term $1 - \eta_i$ is the proportion of out of merit costs allocated to SRAS
- w_i is a filter that removes non-Synergy plant from the calculation of the L component of the Cost_LR parameter proposal.

6.4.3 The optimisation process

The SRAS and LRR optimisation algorithm solves for the minimum cost mix of all generation units that are able to provide SRAS and LRR in each trading interval of the modelling period. Optimisation is on the basis of generation units' marginal cost functions in each trading interval. This method will be applied under constraints such that:

- Contracted SRAS is prioritised over Synergy's SRAS capacity
- The sum of all units' SRAS levels will be set to meet or exceed the SRAS requirement in a trading interval (determined in step 6.3)
- The output of each generation unit providing SRAS remains within its rated operational bounds, taking into account planned and unplanned, full and partial outages (determined in step 6.2 above)

- The sum of all units' LRR levels will be set to meet or exceed the LRR requirement in a trading interval (determined in step 6.3)
- If the SRAS or LRR requirement is not met in a trading interval, available facilities are dispatched out of merit in order from low cost to high cost plants and the optimisation algorithm is run again
- As described in Section 6.4.1, start-up costs are recorded in both the pre-optimisation and post-optimisation modelling phases, as well as the reason for out of merit start-up either being due to the need to meet SRAS or LRR requirements, and are allocated between SRAS and LRR allocation costs in proportion to their relative shares of total out of merit start-ups
- Withholding certain generators' capacity to reflect application of the ready reserve standard in line with section 3.5.

EY's SRAS and LRR cost optimisation algorithm will be applied to answer two questions for each trading interval:

- What level of output will each Synergy generation unit that is available to provide SRAS and LRR operate at to meet the SRAS and LRR requirements at least overall cost?
- What is the lowest overall cost at which the SRAS and LRR requirements can be met by all plant?

The opportunity cost of in-merit plants that withhold output to provide SRAS are added to the direct operating losses of out of merit units providing SRAS and LRR, and the optimisation minimises the total of these combined costs.

Expressing the problem mathematically in a simplified format, the SRAS and LRR cost optimisation algorithm solves the following non-linear, constrained minimisation problem conducted for $t = 1,2,3, \dots T$:

$$\begin{aligned} &\textit{minimise} && \sum_{i\in\Phi} C_i(s_i) + \sum_{i\in\Upsilon} C_i(X_i) \\ &\textit{subject to} && \sum_{i=1}^{N} s_i \geq S - M - I \\ & && s_i \leq \phi_i \\ & && \sum_{i=1}^{N} r_i - \beta \geq R \\ & && r_i \leq \theta_i \end{aligned} \tag{7}$$

where:

- s_i is the quantity of SRAS provided by generating unit i, $\{s_i \geq 0\}$
- Φ is the set of in-merit units
- Υ is the set of units operating out of merit to provide SRAS and/or LRR
- $C_i(s_i)$ is the opportunity cost of providing SRAS for in-merit-units, equivalent to the net revenue forgone in the balancing market
- $C_i(X_i)$ is the operating losses of unit i that is required to operate out of merit to provide SRAS and/or LRR
- X_i is the optimal output of unit i
- S is the dynamic SRAS requirement net of LFAS capacity contributing to SRAS in trading interval t

- M is the MW capacity of long term interruptible load contracts (non-Synergy) for SRAS, with terms that require AEMO to prioritise them for SRAS over the use of generation units
- I is the MW capacity of short term non-Synergy (i.e. independent power producer) SRAS in trading interval t
- R is the dynamic LRR requirement in trading interval t
- r_i is the quantity of LRR provided by generating unit i, $\{r_i \geq 0\}$
- β is simulated LFAS down consumed by Synergy units, left-censored at zero, right censored at the LFAS down requirement
- ϕ_i denotes assumed maximum SRAS capability of plant i
- θ_i denotes assumed maximum LRR capability of plant i.

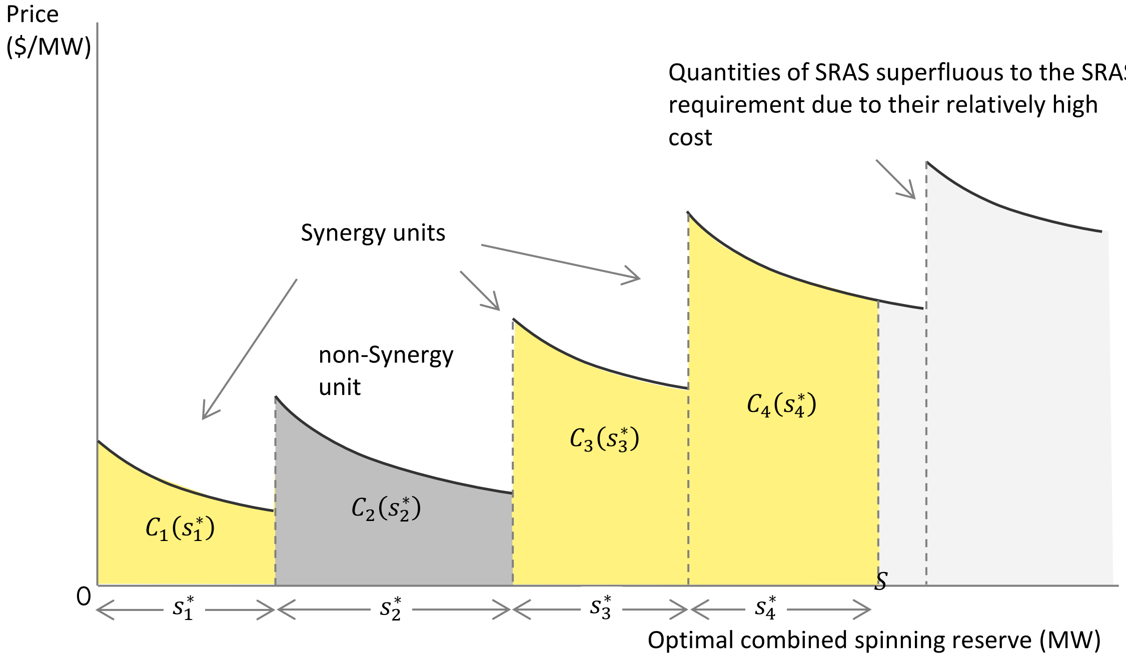
Further constraints ensure generators' minimum and maximum generation levels are not exceeded after accounting for plant outages. Expression (7) therefore solves for the least-cost combination of SRAS and LRR quantities from the N generation units, which includes both Synergy and non-Synergy plant, as a constrained optimisation problem.

Non-Synergy provision of SRAS, denoted by M, and I, are based on AEMO's determination (see Section 3.7).

The optimisation concept for in-merit units is depicted in Figure 18 below, where the marginal opportunity cost of providing SRAS for a generation unit is equal to the balancing price minus the generation unit heat rate-based marginal cost function, but horizontally reflected so that costs are given a function of increasing SRAS rather than increasing output of energy.

In the example diagram, the optimisation has resulted in the reserved output from three Synergy and one non-Synergy plant.

Figure 18: Graphical representation of the spinning reserve optimisation concept



6.5 Balancing price modelling

The outputs from steps 6.1 to 6.4 will be used as inputs to EY's 2-4-C® dispatch model.

The 2-4-C® model will be run to provide a balancing price forecast for each trading interval over the modelling period, now considering capacity allocated to SRAS to be bid at the market price ceiling and capacity allocated to LRR at the floor price.

6.6 Forecast of the total opportunity cost of SRAS and out of merit LRR provision

This step will apply the same optimisation algorithm as step 6.4, but will now include the balancing price derived from step 6.5 as an input.

The minimised objective cost function will give the total opportunity cost of SRAS provision and the cost of LRR provision for each trading interval.

6.7 Calculation of Synergy's SRAS and LRR availability cost

Upon completion of step 6.6, the opportunity costs associated with non-Synergy SRAS plant and Synergy LFAS plant that concurrently provide SRAS will be removed from the minimised objective cost function to calculate Synergy's SRAS availability payment.

Synergy's opportunity cost of providing SRAS in each trading interval t of a financial year ($t = 1,2,3,\dots,T,\ T$ being the number of trading intervals in the year) is given by Equation (8) below:

$$\begin{gathered} A_t = \alpha_t \frac{1}{2} \max[0, p_t](F_t - U_t + H_t + \Gamma_t - M_t - I_t), \\ A_t \geq 0,\ b \geq p_t \geq a, F_t \geq 0, \\ U_t \geq 0,\ H_t \geq 0,\ M_t \geq 0, I_t \geq 0, \end{gathered} \tag{8}$$

where:

- A_t is Synergy's SRAS opportunity cost for trading interval t
- α_t represents the Margin_Peak or Margin_Off-Peak parameter
- p_t is the balancing price for trading interval t
- F_t is the SRAS requirement for the whole WEM in trading interval t
- U_t is the MW capacity necessary to cover the requirement for providing LFAS up for trading interval t
- H_t is the MW quantity of LFAS up capacity that does not contribute to meeting the SRAS requirement
- Γ_t is simulated LFAS up consumed by Synergy units, left-censored at zero, right censored at the LFAS up requirement
- M_t is the MW capacity of long term interruptible load contracts (non-Synergy) for SRAS, with terms that require AEMO to prioritise them for SRAS over the use of generation units
- I_t is the MW capacity of short term non-Synergy (i.e. independent power producer) SRAS contracts in trading interval t
- The scalar of one half on the right-hand side of Equation (8) converts MW values into MWh values for each half hour trading interval.

To summarise Equation (8) in words, Synergy's SRAS opportunity cost is defined by multiplying a coefficient against:

- The balancing price, and
- The volume of SRAS provided by Synergy units that are not also providing LFAS up.

If we let s_i^* denote the optimal amount of SRAS provided by generation units $i = 1, 2, 3 \dots, N$, i.e. to achieve the least-cost solution to Expression (7), then Synergy's availability cost can be calculated as follows:

$$A = \sum_{i=1}^{N} C_i(s_i^*).w_i, \quad w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases} \tag{9}$$

where w_i is a filter that removes the opportunity cost of non-Synergy plant from the summation of A.

6.8 Calculation of SR_Capacity_Peak and SR_Capacity_Off-Peak parameters

The calculation of the average SRAS capacity for peak and off-peak trading intervals entails taking the arithmetic average of the dynamic SRAS requirement (step 6.3 above), plus the LFAS capacity not contributing to SRAS over peak and off-peak trading intervals, plus Synergy facility LFAS up consumed.

Synergy is compensated for its provision of SRAS in accordance with an administered payment process defined by the formula prescribed in clause 9.9.2(f) of the WEM Rules. The SRAS payment formula that applies to each trading interval t in a financial year, $t = 1,2,3, \dots, T$, is given by:

$$R = \alpha \frac{1}{2} \max[0, p] \max[0, K - U - M - I], \tag{10}$$

where R_t denotes Synergy's SRAS revenue requirement, and K_t is the SR_Capacity_Peak parameter if trading interval t is a peak trading interval, or is the SR_Capacity_Off-Peak parameter otherwise.

If K is solved separately for each trading interval, then by letting $R = A$ it can be shown that:

$$K = F + H + \Gamma.^{28} \tag{11}$$

For the purposes of market settlement, K is expressed as two fixed values, one being an average across peak trading intervals for a year and the other being an average across off-peak trading intervals for a year. As such, and in light of Equation (11), AEMO requires the SR_Capacity_Peak and SR_Capacity_Off-Peak parameter to be given by:

$$K_t = \begin{cases} \dfrac{\sum_{t \in P} F_t + H_t + \Gamma_t}{|P|}, & \forall\, t \in P \\ \dfrac{\sum_{t \in O} F_t + H_t + \Gamma_t}{|O|}, & \forall\, t \in O \end{cases}, \tag{12}$$

[28] To see this, substituting Equations (8) and (10) into $R_t = A_t$ and assuming $R_t > 0$ and $A_t > 0$, we have:

$$\begin{aligned} \alpha_t \frac{1}{2} p_t(K_t - U_t - M_t - I_t) &= \alpha_t \frac{1}{2} p_t(F_t - U_t + H_t + \Gamma_t - M_t - I_t) \\ \Rightarrow \quad K_t - U_t - M_t - I_t &= F_t - U_t + H_t + \Gamma_t - M_t - I_t \\ \Rightarrow \quad K_t &= F_t + H_t + \Gamma_t \end{aligned}$$

$$Q.E.D.$$

where P is the set of peak trading intervals in the year, where O is the set of off-peak trading intervals in the year, set membership is denoted by the symbol $\in$, the cardinality of a set P is denoted $|P|$ (i.e. $|P|$ denotes the number of peak trading intervals in a year), and the symbol $\forall$ denotes the universal quantifier (which means for all).

6.9 Calculation of Margin_Peak and Margin_Off-Peak parameters

The outputs of steps 6.1 to 6.8 will be used as variables in a linear regression model. The solution to the regression model will provide the Margin_Peak and Margin_Off-Peak parameter values.

This section will propose a method of calculating the Margin_Peak and Margin_Off-Peak parameters consistent with the recommendations proposed by the ERA in section A2.2 of the ERA 2018 Determination, and an alternative, arithmetic average margin values calculation method that produces simulated SRAS payments that compensate for simulated availability costs across all Monte Carlo samples.

The steps outlined in the preceding sub-sections of this report enable calculation of the variables contained in the equation in Figure 19 below.

Figure 19: Representation of the inputs into the regression model to derive Margin Values

The R vector will be derived by means of the methods described in the sections above

The U vector will be the LFAS up requirement in MW

The M vector will be the long-term contracts for interruptible load in MW

The I vector will be the simulated optimal non-Synergy spinning reserve in MW

$$R_t = \alpha_t \frac{1}{2} \max[0, p_t] \max[0, K_t - U_t - M_t - I_t]$$

The p vector will be derived from the balancing price market modelling output

The K vector will be the SR_Capacity_Peak and SR_Capacity_Off-Peak values determined to reflect the requirements of clause 3.10.2 of the Rules

This allows for estimation of the Margin_Peak and Margin_Off-peak parameters, $\hat{\alpha}_t$, by means of regression analysis, aimed at achieving $R_t \approx A_t$ over the 2020-21 financial year. EY will adopt a standard approach to regression analysis and reporting.

As outlined above, model specification is part of a process that depends upon the preliminary analysis of the input data and examination of the residuals from a number of model fitting attempts. One possible function form for the regression models that will be used in this modelling exercise is:

$$A_t = \hat{\alpha}\, Z_t + u_t, \quad u_t \sim \mathcal{N}(0, \sigma^2), \tag{13}$$

where:

- u_t is a random error term
- $\hat{\alpha}$ is the coefficient to be estimated by minimising the sum of the squared residuals from the regression.

and where:

$$Z_t = \frac{1}{2} \max[0, p_t] . \max[0, K_t - U_t - M_t - I_t]. \tag{14}$$

Also reported in this report is an alternative to the regression analysis method, this being the arithmetic margin values calculation method. This approach to margin values calculation is informed by the relationship:

$$\sum_t A_t = \hat{\alpha} \sum_t Z_t \, , \tag{15}$$

which implies:

$$\hat{\alpha} = \frac{\sum_t Z_t}{\sum_t A_t}.$$

6.10 Calculation of LRR response costs

A generating unit may be instructed to curtail its generation output in response to an actual load rejection event and as a result would incur lost revenue resulting from forgone energy sales at the prevailing balancing price.

The energy profits forgone as a result of a generator unit being curtailed to provide LRR are a function of:

- the prevailing balancing price at the time of the load rejection event[29] occurring, and
- the LRR response quantity.[30]

Load rejection events can occur at any time of the year and are dependent on network outages and the coincident system conditions. However, load rejection events that have led to over-frequency in the SWIS are rare,[31] and the response required from LRR has historically been limited to within a 30 minute trading interval.[32]

Analysis of the forgone energy profits as a result of a load rejection event will be calculated considering an upper bound scenario assuming the load rejection event occurs during a trading interval at the maximum balancing price for a sustained period of two trading intervals. Typically, a maximum of two events may occur in a year based on network outage statistics[33] of key bulk transmission circuits.

An example calculation is provided below. The LRR response cost is small in comparison to other market costs and is likely to be immaterial. Nevertheless, the calculation of the 'L' parameter in Cost_LR will include this cost component.

Table 8: Example analysis of a load rejection event occurring at maximum energy price for two trading intervals

Input assumption	Description of data source and value
Load rejection response quantity (MW, sustained over time)	90 MW (set by AEMO requirement)

[29] Defined as an event which causes a facility to respond and sustain or exceed the required response in time periods specified in clause 3.9.7 of the WEM Rules.

[30] Defined in the WEM Rules as the quantity of energy reduction, in MWh, provided by a Facility as a LRR Response due to a Load Rejection Reserve Event, but excluding any such contribution that occurred because AEMO had instructed the Facility to provide Downwards LFAS Enablement or Backup Downwards LFAS Backup Enablement.

[31] AEMO provided information to EY regarding over-frequency events in the SWIS. A total of 11 load rejection events resulted in over-frequency occurring since 2013. The required sustained response times in the events ranged from a few minutes up to 28 minutes.

[32] We note that the LRR response is required across two time periods, one that responds in 6 seconds for at least 6 minutes and the other requiring response within 60 seconds for at least 60 minutes. See clause 3.9.7 of the Rules.

[33] We understand that network outage events on the 220 kV network may occur, on average, twice a year.

Input assumption	Description of data source and value
Load rejection response time (highly conservative)	1 hour or two trading intervals[34]
Maximum balancing price (highly conservative)	$235 / MWh[35] (based on maximum STEM price)
Total energy profits forgone @ maximum balancing price for two trading intervals	$21,150

[34] The LRR response requirement is for up to 60 minutes, although the duration of historical load rejection events has fallen short of this requirement.

[35] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits.

7. Sensitivity analysis of modelling results

EY's proposed modelling methodology includes undertaking analysis of sensitivities to key data input assumptions. The purpose of the sensitivity analysis is to:

- compare results obtained from modelling an agreed sensitivity case against the base case results
- investigate how changes to selected input assumptions may impact the modelling outputs
- determine which input variables may have the greatest influence on the modelled outputs
- determine which modelled outputs exhibit the greatest variation driven by assumed changes to inputs variables.

7.1 Methodology

The methodology for sensitivity analysis will involve:

- selecting varied inputs and determining their degree of change
- applying the same modelling approach for modelling a sensitivity case results as for modelling the base case results
- recording and presenting sensitivity results in graphical and tabular forms, and comparing these to the results of the base case results
- analysing sensitivity modelling results against the base case results by calculating arc elasticities (see below) of output variables to assumed input variables to provide a consistent measure of comparison between the modelled sensitivity cases.

- The arc elasticity concept is defined as follows:

$$Arc\ elasticity = \frac{\%\ change\ in\ output}{\%\ change\ in\ driver\ (input)}.$$

  The midpoint formula will be used for calculation of arc elasticities. This formula uses the midpoint of a move from value V_0 to value V_1, as follows:

$$\%\ change\ (input\ or\ output) = \frac{V_1 - V_0}{(V_0 + V_1)/2}.$$

- forming a conclusion on the overall sensitivity of base case modelling results to the modelled changes in assumption sets.

7.2 Definition of sensitivities

EY consulted with AEMO to select modelling assumptions to be varied from the base case. For the 2018 AS review, EY conducted analysis on the sensitivity of results to gas price changes and thermal generation outage rates.

For the 2019 AS parameters modelling, the following sensitivities were modelled:

- Sensitivity 1A (Svity 1A): Synergy gas units face a 50% higher gas price than under the base case, i.e. $5.25/GJ as opposed to $3.50/GJ
- Sensitivity 1B (Svity 1B): Synergy gas units face a 100% higher gas price than under the base case, i.e. $7.00/GJ as opposed to $3.50/GJ
- Sensitivity 2A (Svity 2A): Yandin and Warradarge wind farm dispatch level reduced by 20% in every trading interval

- Sensitivity 2B (Svity 2B): combined output of Yandin and Warradarge (inclusive of load reduction as per section 3.1) limited to the output of the single largest generating unit online in the previous interval.

Apart from the abovementioned variations to input assumptions, all other inputs to the AS optimisation model remained unchanged from the base case modelling. The rationale for selecting the above inputs to vary was as follows:

- For Sensitivity 1A and Sensitivity 1B: the gas price was viewed as a key input likely to impact the short run average cost of Synergy's gas-fired generating units. Given the uncertainty around Synergy's gas price raised in section A.9, varying this input was viewed as a means to assess the materiality of the Synergy's gas price assumed in the base case modelling
- For Sensitivity 2A and Sensitivity 2B: the possible curtailment of Yandin and Warradarge wind farm under the GIA scheme may result in changed SRAS requirement in certain intervals, as described in section 3.1. Varying the level of curtailment of these wind farms was viewed as a means to assess the materiality of the various curtailment levels or operational frameworks possible under the GIA

8. Key modelling outcomes for AS parameters

8.1 Results of base case modelling

As agreed with AEMO, the base case for the SRAS and LRR modelling included non-Synergy SRAS as outlined in section 3.7. Results of the modelled base case are presented in Table 9.

Table 9: Results of base case modelling

Item	Unit	Base case
Average_SR_Requirement_Peak[36]	MW	187.73
Average_SR_Requirement_Off-Peak[36]	MW	178.46
Average_Synergy_SR_Requirement_Peak[37]	MW	80.87
Average_Synergy_SR_Requirement_Off-Peak[37]	MW	95.74
Arithmetic_Average_Balancing_Price_Peak	$/MWh	35.15
Arithmetic_Average_Balancing_Price_Off-Peak	$/MWh	31.16
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Peak	$/MWh	39.02
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Off-Peak	$/MWh	31.77
Average_Annualised_Availability_Cost_Peak	$m	5.063
Average_Annualised_Availability_Cost_Off-Peak	$m	2.419
Margin_Value_Peak	%	39.65
Margin_Value_Off-Peak	%	23.24
Arithmetic_Margin Value_Peak	%	31.40
Arithmetic_Margin Value_Off-peak	%	21.79
SR_Capacity_Peak[38]	MW	251.66
SR_Capacity_Off-Peak[38]	MW	240.24
Average_Annualised_Load_Rejection_Cost_Peak	$m	0.175
Average_Annualised_Load_Rejection_Cost_Off-Peak	$m	0.546
Average_Annualised_Load_Rejection_Requirement_Peak[39]	MW	79.42
Average_Annualised_Load_Rejection_Requirement_Off-Peak[39]	MW	84.99

[36] Calculated in line with section 3.1 and 6.3

[37] Average Synergy SRAS requirement is a difference between the SR_capacity parameter (peak/off-peak) and LFAS up cleared, SRAS provided by interruptible loads and SRAS provided by independent power producers. For reconciliation see section 9.1

[38] The SR_Capacity parameter (peak/off-peak) is sum of the modelled WEM-wide SRAS requirement, cleared LFAS up that does not contribute to SRAS provision and LFAS up consumed from facilities capable of providing SRAS. For reconciliation see section 9.1, and also section 6.8

[39] The LRR requirement is calculated in line with section 3.4 and 6.3, with regard for Boddington Gold Mine load, Eastern Goldfield load and load relief

8.2 Results of sensitivity modelling

Results of the modelled sensitivities (and base case modelled results) are presented in Table 10.

Table 10: Results of sensitivity modelling

Item	Unit	Base case	Svity 1A	Svity 1B	Svity 2A	Svity 2B
Average_SR_Requirement_Peak	MW	187.73	188.17	188.84	182.61	180.74
Average_SR_Requirement_Off-Peak	MW	178.46	178.90	179.20	168.36	165.10
Average_Synergy_SR_Requirement_Peak	MW	80.87	81.24	81.91	75.67	73.81
Average_Synergy_SR_Requirement_Off-Peak	MW	95.74	96.16	96.46	85.62	82.36
Arithmetic_Average_Balancing_Price_Peak	$/MWh	35.15	40.47	43.63	37.38	36.27
Arithmetic_Average_Balancing_Price_Off-Peak	$/MWh	31.16	37.36	40.87	33.06	33.03
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Peak	$/MWh	39.02	44.59	47.96	40.94	39.99
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Off-Peak	$/MWh	31.77	37.89	41.37	32.94	32.64
Average_Annualised_Availability_Cost_Peak	$m	5.063	5.042	4.919	5.262	5.134
Average_Annualised_Availability_Cost_Off-Peak	$m	2.419	3.353	3.802	2.276	2.078
Margin_Value_Peak	%	39.65	25.46	20.60	43.51	44.46
Margin_Value_Off-Peak	%	23.24	21.42	20.24	25.77	25.37
Arithmetic_Margin Value_Peak	%	31.40	27.24	24.51	33.24	34.04
Arithmetic_Margin Value_Off-peak	%	21.79	25.21	26.10	22.10	21.18
SR_Capacity_Peak	MW	251.66	252.03	252.69	246.46	244.59
SR_Capacity_Off-Peak	MW	240.24	240.66	240.96	230.12	226.86
Average_Annualised_Load_Rejection_Cost_Peak	$m	0.175	0.274	0.430	0.144	0.160
Average_Annualised_Load_Rejection_Cost_Off-Peak	$m	0.546	0.893	1.349	0.327	0.377
Average_Annualised_Load_Rejection_Requirement_Peak	MW	79.42	79.42	79.42	79.42	79.42
Average_Annualised_Load_Rejection_Requirement_Off-Peak	MW	84.99	84.99	84.99	84.99	84.99

8.3 Elasticities of outputs modelled under the sensitivities

Elasticities of outputs modelled under the sensitivities are presented in Table 11. Based on the elasticity formula presented in section 7, a positive elasticity value indicates a change in the same direction (i.e. growth in input, growth in output or decrease in input, decrease in output). A negative elasticity value indicates converse changes between an input and an output.

Elasticity can be understood as illustration of sensitivity of an output per 1% change of a single underlying driver (input). Elasticity above 1 indicates a high degree of sensitivity whereas elasticity below 1 indicates a low degree of sensitivity.

Table 11: Results of sensitivity modelling – elasticities

Modelled output	Sensitivity 1A	Sensitivity 1B	Sensitivity 2A	Sensitivity 2B
Average_SR_Requirement_Peak	0.01	0.01	0.12	0.30
Average_SR_Requirement_Off-Peak	0.01	0.01	0.26	0.61
Average_Synergy_SR_Requirement_Peak	0.01	0.02	0.30	0.71
Average_Synergy_SR_Requirement_Off-Peak	0.01	0.01	0.50	1.18
Arithmetic_Average_Balancing_Price_Peak	0.35	0.32	-0.28	-0.25
Arithmetic_Average_Balancing_Price_Off-Peak	0.45	0.40	-0.27	-0.46
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Peak	0.33	0.31	-0.22	-0.19
Synergy_SR_Req_Weighted_Censored_Average_Balancing_Price_Off-Peak	0.44	0.39	-0.16	-0.21
Average_Annualised_Availability_Cost_Peak	-0.01	-0.04	-0.17	-0.11
Average_Annualised_Availability_Cost_Off-Peak	0.81	0.67	0.27	1.19
Margin_Value_Peak	-1.09	-0.95	-0.42	-0.90
Margin_Value_Off-Peak	-0.20	-0.21	-0.46	-0.69
Arithmetic_Margin Value_Peak	-0.35	-0.37	-0.26	-0.63
Arithmetic_Margin Value_Off-peak	0.36	0.27	-0.06	0.22
SR_Capacity_Peak	0.00	0.01	0.09	0.22
SR_Capacity_Off-Peak	0.00	0.00	0.19	0.45
Average_Annualised_Load_Rejection_Cost_Peak	1.10	1.26	0.87	0.70
Average_Annualised_Load_Rejection_Cost_Off-Peak	1.21	1.27	2.26	2.87
Average_Annualised_Load_Rejection_Requirement_Peak	0.00	0.00	0.00	0.00
Average_Annualised_Load_Rejection_Requirement_Off-Peak	0.00	0.00	0.00	0.00

The highest positive elasticities are observed for:

- ► The modelled average annualised LRR cost (peak and off-peak) in all sensitivities. This indicates that this output is highly sensitive to changes in inputs tested for each sensitivity case. The LRR cost increases in line with assumed Synergy's gas price increase, and decreases when the output of Yandin and Warradarge is reduced
- ► The modelled average annualised availability cost off-peak in all sensitivities
- ► The modelled average Synergy SRAS requirement (peak and off-peak) in Sensitivity 2A.

The highest negative elasticities are observed for:

- The modelled margin value peak and off-peak in all sensitivities, which indicates that these outputs react conversely to the assumed direction of changes in inputs. The margin values calculated through a regression technique are observed to be more sensitive to change when compared to the arithmetic average calculation method.
- The modelled arithmetic average margin value peak, which indicates that this output reacts conversely to the assumed direction of changes in inputs.

As the underlying credible contingency that drives the LRR requirement is unchanged in the sensitivity cases, the elasticity factor for this variable is nil.

9. Analysis and commentary of modelling outcomes

The purpose of any modelling exercise is to produce an abstract representation of the relationship between the inputs and outputs of an actual system. Without the development and testing of a model, the outcomes produced from a complex system can be difficult to understand and predict. For this reason, it is a basic modelling principle that a base or expected case scenario should not be selected solely on the basis of its outputs, but rather in conjunction with the soundness of the model's structure and the validity of its inputs.

A description of this year's model and its inputs, developed in consultation with AEMO and market participants, is given in section 4. The model was calibrated on the basis of the backcasting as described in section 5. The aim of backcasting and model calibration was to ensure that:

- Input assumptions used in the modelling were validated and modified if necessary
- Any significant variances or material errors observed in the model outcomes relative to actual data were identified and addressed
- Reasonable assurance can be obtained that the model is fit for purpose and its outputs are free of material errors.

Additionally, in order to ensure that assumptions and outputs align with the WEM Rules and AEMO's operational practices, EY and AEMO identified key market developments impacting the modelling of AS parameters and discussed operational practices in the WEM (section 3).

Comparison of the modelling outcomes produced over a range of sensitivities, where only one input variable is modified to produce a new set of outputs, can provide a simple means of sense checking of modelling outcomes. The modelling of sensitivities (section 7 and section 8) shows how changes to selected input assumptions impact the modelling outputs. The sensitivities should not be considered as alternative scenarios to the base case but should be seen as a way to test the model's behaviour and robustness.

These processes combined, rather than the modelling outcomes alone, inform the overall characteristics of the base case scenario. For detailed descriptions of the processes performed to establish the assumptions and model configuration, please refer to section 3, section 4, section 5, section 7, section 8.

9.1 Cost of providing SRAS from Synergy facilities

Modelled results relating to cost of providing SRAS from Synergy facilities were presented in section 8.1 and section 8.2. In line with section 6.7, the key underlying factors shaping the cost of providing SRAS from Synergy facilities are (both for peak and off-peak intervals) are:

- The modelled variable fuel and O&M and fixed startup costs for each facility
- The modelled balancing market price
- The modelled Synergy SRAS requirement

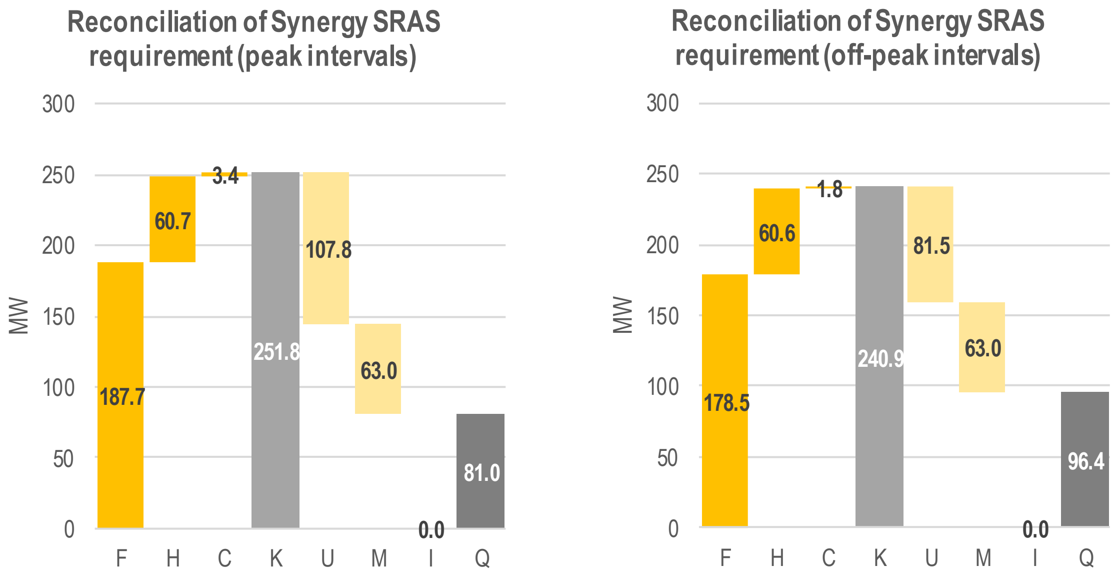
The margin value parameters are an outcome of the modelling. The margin values are derived from the cost of providing SRAS, the quantum of SRAS provided by Synergy facilities and the prevailing balancing market price. The modelled balancing prices are a result of generation cost input assumptions and modelled post-optimised dispatch. The modelled Synergy SRAS requirement (symbol Q with its components reconciled in Figure 20) is a derivative of:

- The modelled WEM-wide SRAS requirement (symbol F in Figure 20)

- Cleared LFAS up that does not contribute to SRAS provision (symbol H in Figure 20)
- LFAS up consumed[40] (symbol C in Figure 20)
- SR_Capacity parameter (symbol K in Figure 20)
- LFAS up cleared (symbol U in Figure 20)
- SRAS provided by interruptible loads (symbol M in Figure 20)
- SRAS provided by independent power producers (symbol I in Figure 20).

The reconciliation presented here is based on one randomly chosen Monte Carlo modelling iteration for illustration purposes.

Figure 20: Reconciliation of drivers of modelled Synergy's SRAS requirement (based on one Monte Carlo iteration)



The modelled WEM-wide SRAS requirement is modelled in line with the logic presented in section 3.1 and section 6.3.

- Cleared LFAS up that does not contribute to SRAS provision is the portion of cleared LFAS up provided by units which do not simultaneously provide SRAS in the optimisation process.
- LFAS up consumed reflects real-time consumption of LFAS up considered when determining costs and compensation for SRAS, as a result of the public consultation process described in section 1.2.
- The SR_Capacity parameter is the sum of the above.
- LFAS up cleared is the average quantity of LFAS up cleared in peak and off-peak hours, resulting from the LFAS requirement set as per section 3.2 (116 MW or 70 MW, noting that LFAS requirement times do not fully align with peak and off-peak interval times).
- SRAS provided by non-Synergy providers as per section 3.7.
- Synergy's SRAS requirement is the difference between SR_Capacity, LFAS up cleared, SRAS provided by interruptible loads and SRAS provided by independent power producers.

[40] Left-censored at zero, right-censored at the LFAS up requirement.

As shown in Figure 21 and Figure 22, the modelled SRAS cost for all considered modelling cases coincides with changes in all three modelled drivers as specified earlier (Synergy facility input costs, balancing price and Synergy's SRAS requirement) and a combination thereof.

Figure 21: Modelled Synergy's SRAS cost for peak periods

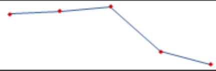
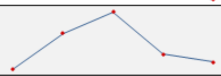
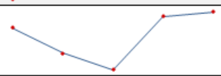
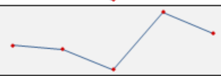
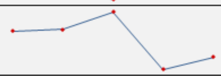
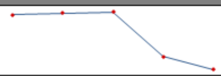
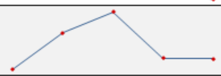
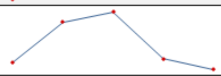
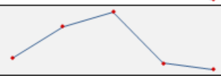
Components of modelled Synergy's availability cost for peak intervals	BASE	Sensitivity 1A	Sensitivity 1B	Sensitivity 2A	Sensitivity 2B	Tendency across modelled cases
Modelled average Synergy's SRAS requirement [MW]	80.87	81.24	81.91	75.67	73.81	
Modelled arithmetic average balancing price [$/MWh]	35.15	40.47	43.63	37.38	36.27	
Modelled arithmetic average margin value [%]	31.4%	27.2%	24.5%	33.2%	34.0%	
Modelled average annualised availability cost [$m]	5.06	5.04	4.92	5.26	5.13	
Modelled SRAS provided [GWh], based on one interation	898.31	899.17	907.75	879.46	885.54	

Figure 22: Modelled Synergy's SRAS cost for off-peak periods

Components of modelled Synergy's availability cost for off-peak intervals	BASE	Sensitivity 1A	Sensitivity 1B	Sensitivity 2A	Sensitivity 2B	Tendency across modelled cases
Modelled average Synergy's SRAS requirement [MW]	95.74	96.16	96.46	85.62	82.36	
Modelled arithmetic average balancing price [$/MWh]	31.16	37.36	40.87	33.06	33.03	
Modelled arithmetic average margin value [%]	21.8%	25.2%	26.1%	22.1%	21.2%	
Modelled average annualised availability cost [$m]	2.42	3.35	3.80	2.28	2.08	
Modelled SRAS provided [GWh], based on one interation	571.84	577.47	576.31	516.23	516.70	

As illustrated in the above tables the modelled availability cost in Sensitivity 1A and Sensitivity 1B (as compared to the Base case) is relatively unchanged during peak periods, despite the increasing balancing market price. For off-peak periods a more intuitive relationship is observed in which the availability cost rises along with increasing Synergy facility gas price. In the peak periods the opportunity cost (SRAS providing facility cost minus balancing market price) declines as Synergy facility gas price increases. This is in part due to Synergy gas generation facilities frequently being marginal balancing market price setters as well as SRAS providers.

Lower total values of Synergy's SRAS cost in Sensitivity 2A and Sensitivity 2B against the Base case coincide with a decrease in modelled Synergy SRAS requirement. The decrease in modelled Synergy SRAS requirement in Sensitivity 2A and Sensitivity 2B (as compared to the Base case) results from Yandin and Warradarge wind farms setting the WEM-wide SRAS requirement less often and at a lower level than in the Base case (see Figure 23). This coincides with the wind farms' output being assumed to be constrained down (see section 7.2). The Yandin plus Warradarge contingency still sets the SRAS requirement in Sensitivity 2B for some intervals as it is limited to the dispatch quantity of the largest unit from the previous trading interval. It therefore may set the requirement in subsequent intervals where thermal generation units ramp down from one interval to the next. However, in these instances the SRAS requirement set by this condition would be only marginally higher than the dispatch of the thermal unit that is ramping down. It is observed that the average

SRAS requirement set by Yandin plus Warradarge is relatively low at 144 MW. Figure 28 below shows the impact on dispatch for Yandin plus Warradarge in these sensitivity cases.

Figure 23 shows WEM-wide SRAS setters in the Base case, Sensitivity 2A and Sensitivity 2B, based on one sample Monte Carlo iteration.

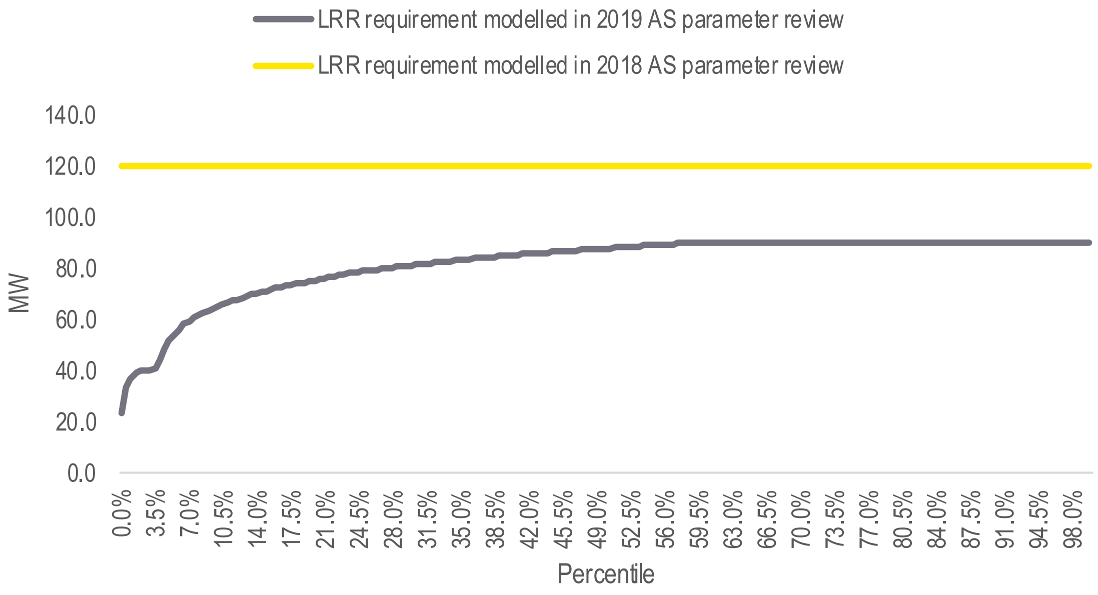
Figure 23: WEM-wide SRAS setters in the Base case, Sensitivity 2A and Sensitivity 2B (based on one Monte Carlo iteration)

Unit	Case	Average SRAS requirment [MW] set by the unit	# intervals where the units sets SRAS requirement
BW1_BLUEWATERS_G2	Base case	158.89	504
	Svity_2A	158.82	584
	Svity_2B	159.10	587
BW2_BLUEWATERS_G1	Base case	158.60	5,135
	Svity_2A	158.28	5,841
	Svity_2B	158.30	5,872
COCKBURN_CCG1	Base case	173.78	433
	Svity_2A	174.00	477
	Svity_2B	173.80	444
COLLIE_G1	Base case	207.47	3,605
	Svity_2A	205.62	3,890
	Svity_2B	205.70	3,814
NEWGEN_KWINANA_CCG1	Base case	187.04	3,807
	Svity_2A	183.58	4,300
	Svity_2B	174.60	5,095
NEWGEN_NEERABUP_GT1	Base case	206.59	215
	Svity_2A	206.72	243
	Svity_2B	206.30	217
Others	Base case	123.75	99
	Svity_2A	120.71	115
	Svity_2B	122.14	122
YANDIN_WF1_and_WARRADARGE_WF1	Base case	195.50	3,722
	Svity_2A	160.48	2,070
	Svity_2B	144.15	1,369

9.2 Cost of providing LRR from Synergy facilities

Modelled results relating to Synergy's LRR cost were presented in section 8.1 and section 8.2. LRR cost is generally very low in most trading intervals throughout the year. In comparison to last year's review, this has primarily been driven by a material decrease in the dynamic LRR requirement as outlined section 3.4 and also illustrated in Figure 24 below. However, in low demand periods when many facilities are operating at minimum load, costs arise when facility dispatch has to be increased by LRR providers at the expense of low cost dispatch from other facilities. At times a gas generation facility is required to be committed out of merit in order to provide the service which also results in a cost of starting the facility.

Figure 24: Modelled LRR requirement duration curve



A summary of modelled LRR provision by unit is shown in Figure 25, based on one Monte Carlo iteration.

Figure 25: Summary of Synergy's modelled LRR provision by unit (based on one Monte Carlo iteration)

LRR provider	LRR (FCAST) provided in-merit and out-of-merit, GWh	Out-of-merit LRR (FCAST), GWh	Out-of-merit LRR (FCAST), GWh, peak intervals	Out-of-merit LRR (FCAST), GWh, off-peak intervals
COLLIE_G1	87.2	0.0	0.0	0.0
KEMERTON_GT11	0.0	0.0	0.0	0.0
KEMERTON_GT12	0.1	0.1	0.0	0.1
KWINANA_GT2	218.8	0.0	0.0	0.0
KWINANA_GT3	119.6	1.9	0.1	1.8
MUJA_G5	92.2	0.0	0.0	0.0
MUJA_G6	90.2	0.0	0.0	0.0
MUJA_G7	127.8	0.0	0.0	0.0
MUJA_G8	117.5	0.0	0.0	0.0
PINJAR_GT1	2.1	0.0	0.0	0.0
PINJAR_GT10	62.6	2.6	0.2	2.4
PINJAR_GT11	78.1	2.8	0.3	2.5
PINJAR_GT2	0.3	0.0	0.0	0.0
PINJAR_GT3	0.1	0.0	0.0	0.0
PINJAR_GT4	31.2	0.1	0.0	0.1
PINJAR_GT5	28.2	0.2	0.1	0.1
PINJAR_GT7	26.6	0.8	0.3	0.5
PINJAR_GT9	52.8	2.2	0.5	1.7

In the sensitivity cases assessed, the most significant driver of LRR cost variation is observed to be the cost of gas for Synergy facilities. As the gas cost increases, the out of merit dispatch that needs to occur to meet the LRR requirement is larger. The higher cost of running gas plant is generally not mitigated by higher balancing market prices as these events occur when demand is low and therefore the balancing price is also low.

The need to start up Synergy's units out of merit is also a derivative of the LFAS market developments. The assumed increase in IPP providers of LFAS up/down, and the LFAS up/down merit orders (IPPs being cleared for LFAS ahead of Synergy units as per Appendix B), results in Synergy providing on average ~21 MW of LFAS up/down in off-peak intervals, and ~47 MW of LFAS up/down in peak intervals. For off-peak hours, the above implies that Synergy units are on average capable of providing ~21 MW of LRR, and the remainder of the dynamic LRR requirement (~82 MW in off-peak intervals) needs to be covered by either ramping up other in-merit units or starting units out-of-merit for LRR provision. Inclusion in the modelling of consumed LFAS down also reduces the capability of Synergy's in-merit units to provide LRR.

9.3 Wholesale cost of energy

Modelled results relating to the wholesale cost of energy are presented below. Figure 26 and Figure 27 below show modelled wholesale energy cost and modelled balancing prices for the Base case and modelled sensitivities. The modelled wholesale energy cost is a function of modelled balancing prices (different for each modelled case) and modelled SWIS demand (constant for each modelled cases).

The purpose of this report is to determine the AS parameters, therefore the energy costs should be considered as indicative only and should be considered in line with the modelling limitations outlined in section 9.3.

The increase in modelled wholesale energy cost in Sensitivity 1A and Sensitivity 1B (as compared to the Base case) is driven by assumed higher Synergy gas price.

The wholesale energy cost in Sensitivity 2A and Sensitivity 2B is higher than the Base case due to the lower energy production from Yandin and Warradarge wind farm facilities (Figure 28).

Figure 26: Modelled wholesale energy cost and balancing prices for peak intervals

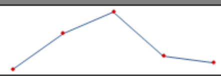
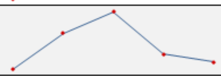
Modelled wholesale energy cost and modelled balancing prices for peak intervals	BASE	Sensitivity 1A	Sensitivity 1B	Sensitivity 2A	Sensitivity 2B	Tendency across modelled cases
Modelled average annualised energy cost peak [$m]	425.05	489.60	528.44	449.89	437.82	
Modelled arithmetic average balancing price [$/MWh]	35.15	40.47	43.63	37.38	36.27	

Figure 27: Modelled wholesale energy cost and balancing prices for off-peak intervals

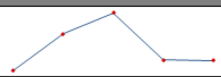
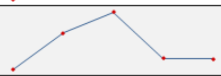
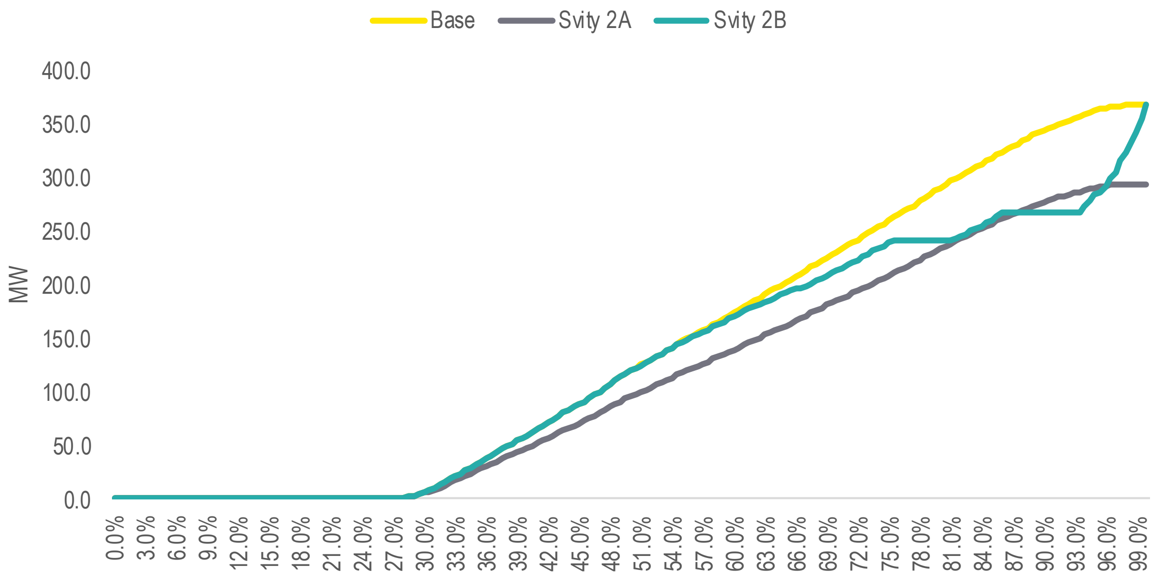
Modelled wholesale energy cost and modelled balancing prices for off-peak intervals	BASE	Sensitivity 1A	Sensitivity 1B	Sensitivity 2A	Sensitivity 2B	Tendency across modelled cases
Modelled average annualised energy cost off-peak [$m]	228.09	274.17	300.36	241.44	241.13	
Modelled arithmetic average balancing price [$/MWh]	31.16	37.36	40.87	33.06	33.03	

Figure 28: Modelled generation duration curves for combined output of Yandin and Warradarge wind farms (Base case, Sensitivity 2A, Sensitivity 2B)



9.4 Regression

In the 2018 Determination, the ERA proposed a regression analysis methodology to determine margin values. The results of an applied regression technique for calculating margin values in this year's review are presented and discussed. However we note that the margin values produced using this technique may provide either an over or under compensation of the availability costs when considering the qualities of the modelling data sets. As such we have also reported an arithmetic average approach to calculating the margin values which would theoretically match the modelled availability costs and provision of SRAS from Synergy facilities. The mathematical definition of both calculation methods is provided in Section 6.9 above.

EY explored a range of regression approaches in the assessment of the margin value parameters. These included:

- Ordinary least squares (OLS) regression
- Generalised least squares regression, which incorporated an autoregressive error structure to manage autocorrelation in the residuals
- An autoregressive integrated moving average algorithm combined with a regression model, again with a view to managing any autocorrelation in the residuals
- A robust linear regression model, applying a M-estimator and a Hampel psi function[41] to manage non-constant variance and non-normality of the residuals
- A Tobit model, noting that the explanatory variable (i.e. allocation costs) is from a censored probability distribution, which are known to impact the efficiency of regression parameter estimates.

The robust OLS linear regression model appears to provide the best fit to the data produced by the integrated SR and LRR model applied in this years' review. Two OLS linear regressions were conducted, one using all the peak trading interval data and the other using all the off-peak trading interval data from the Monte Carlo simulations.

The summary results of the regressions from the R statistical package are provided in Box 1 and Box 2 below.

Box 1 – R summary output of OLS linear regression, peak trading interval data generated by 25 Monte Carlo simulations

```
Call:
lm(formula = A.PEAK ~ 0 + Z.PEAK)

Residuals:
     Min       1Q   Median       3Q      Max
-19081.5   -427.8   -336.7   -213.2  14086.8

Coefficients:
       Estimate Std. Error t value Pr(>|t|)
Z.PEAK 0.396526   0.001115   355.7   <2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 1233 on 255499 degrees of freedom
Multiple R-squared:  0.3312,Adjusted R-squared:  0.3312
F-statistic: 1.266e+05 on 1 and 255499 DF,  p-value: < 2.2e-16
```

[41] Hampel, Ronchetti, Rousseeuw and Stahel (1986). *Robust Statistics*. Wiley, New York, page 150.

Box 2 – R summary output of OLS linear regression, off-peak trading interval data generated by 25 Monte Carlo simulations

```
Call:
lm(formula = A.OFFPEAK ~ 0 + Z.OFFPEAK)

Residuals:
    Min      1Q  Median      3Q     Max 
-5169.9  -297.6  -214.6   -73.9 15024.9 

Coefficients:
          Estimate Std. Error t value Pr(>|t|)    
Z.OFFPEAK 0.232442   0.001181   196.8   <2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 928.3 on 182499 degrees of freedom
Multiple R-squared:  0.175,	Adjusted R-squared:  0.175 
F-statistic: 3.872e+04 on 1 and 182499 DF,  p-value: < 2.2e-16
```

A potential challenge to the regression technique is the presence of outliers, evident in the Normal Q-Q plots of the residuals from the OLS regressions for peak and off-peak intervals across 25 sample simulations provided in Figure 29 below. We note that the residuals of the regression do not follow a normal distribution, otherwise the data points would closely follow the yellow lines in the plots. The off-peak distribution appears to be highly asymmetric, which indicates that OLS may produce a biased estimation of the margin peak and margin off-peak parameter values. Attempts to manage this issue using robust techniques could not produce breakdown points high enough to produce reliable estimates, so the OLS approach was retained.

Figure 29: Normal Q-Q plots of the residuals form the two OLS regressions

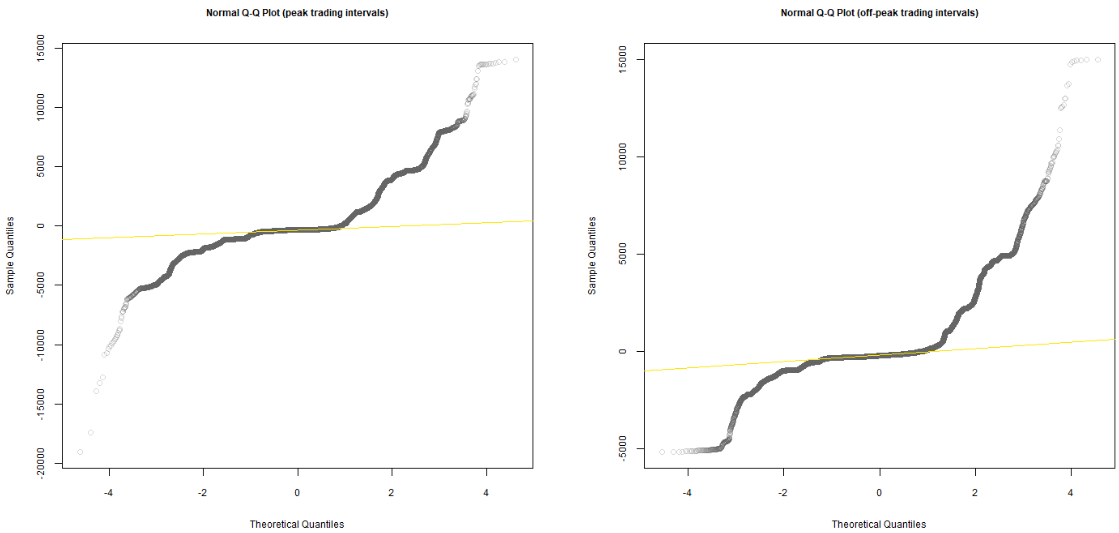
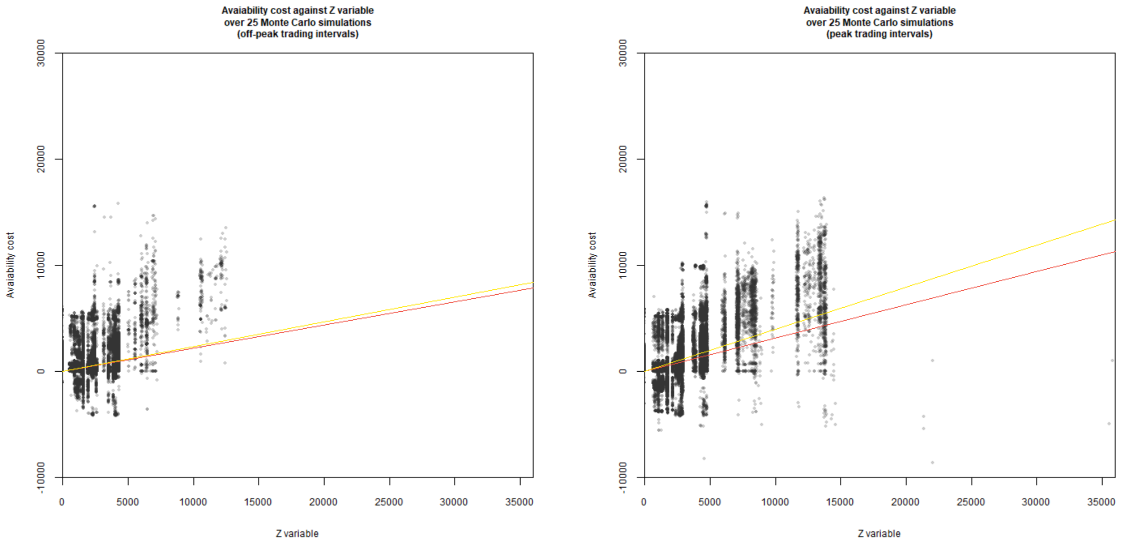


Figure 30 below provides a scatter plot of the availability cost against the Z variable defined in Equation (14) above for both peak and off-peak trading intervals over sample data from 25 Monte Carlo simulations. The red lines in each panel indicate the fitted regression through the origin, the slope of which is equal to the margin value parameter. The yellow lines indicate the arithmetic mean slope, derived by summing all of the availability cost data and then dividing this by the sum of all the Z variable data. It can be seen that the OLS linear regression gives a higher margin value estimate than that based on the arithmetic mean slope for both peak and off-peak trading intervals.

Figure 30: Scatterplots of the peak and off-peak regression variable, the M estimation fit and the slope based on an arithmetic mean



9.5 Modelling limitations

In this year's AS parameter modelling, EY and AEMO endeavoured to capture operating practices and observed market behaviour of MPs (see section 3 and section 5). However, there are inherent limitations to modelling a complex electricity market which mean approximations and simplifications must be made, which results in limitations to the applied modelling approach.

The following points discuss the key limitations of the modelling approach applied in this year's AS parameter modelling:

- A full unit commitment model has not been incorporated, as discussed in response to the question raised by Synergy (section 1.2). As described in Section 5 a heuristic approach has been applied in order to capture a reasonable expectation of unit decommitment operational decisions. This heuristic approach only applies to a selection of large thermal facilities that are also bound by minimum generation constraints. By virtue of the limitations in a pure Linear Programming based model without unit commitment, other facilities in the model are not absolutely bound by minimum generation constraints and can be dispatched linearly from 0 MW to maximum generation in situations where the facility is the marginal supplier. This leads to some instances where marginal facilities are dispatched below their theoretical minimum generation level.
- The ancillary services optimisation routine operates on each trading interval based on the preliminary dispatch outcome. Inter-temporal constraints are not applied in this approach, therefore, it is possible that the optimisation routine cycles the starting and shutdown of out-of-merit GTs across intervals. Starting and stopping a generation facility multiple times within a day would not usually occur in practice due to minimum runtimes and to prevent excessive startup/shutdown costs. Based on an analysis of the dispatch results from selected Monte Carlo iterations, it was found that cycling of facilities does occur in the modelling data set but not often enough to be considered material to the total cost calculations.
- The modelling of dispatch and prices is completed on a facility-bidding basis where each generating unit offers individually into the market. In reality, Synergy follows a portfolio bidding approach.
- Overall, there are aspects of a dynamic market such as revising offer stacks in response to specific events, capturing bilateral electricity and the nature of fuel contracting positions that

are unknown and therefore cannot be incorporated into the modelling for the purpose of this review. Such factors may include:

- ► Facility offers are variable by time of day to capture peak and off-peak trading intervals and may deviate from a unit's short-run average cost (SRAC). Modelling was performed on the SRAC basis and as such does not capture the more dynamic MP offer behaviour
- ► Because the model uses flat offer curves based on the SRAC, the Balancing Merit Order (BMO) is static for the entire study period (notwithstanding plant decommitments and outages). As a result, the model is very sensitive to the input cost assumptions that comprise the SRAC, such as the fuel price and variable O&M costs
- ► As per the backcasting exercise described in section 5, selected input cost assumptions supplied by MPs were modified in order to achieve dispatch outcomes that better align with historical observation. This can lead to input cost assumptions that do not appear to match historical observations. To mitigate these limitations, the sensitivity analyses described in sections 7 and 8.2 are offered to provide insights on the relative impact of changing the input cost assumptions
- ► Static bidding does not simulate the way in which IPPs adjust their offers depending on Synergy's behaviour (shadow bidding) in pursuit of different dispatch outcomes without materially affecting price outcomes

► The balancing market offers of MPs take into account simultaneous offers into the LFAS market, as well as the SRAS and LRR provision by Synergy. The modelling captures this aspect as far as the LFAS market is concerned, while the SRAS and LRR provision is not included in the modelled balancing market offers by design for the purpose of this review.

9.6 Comparison with last year's AS review

This year's review has entailed the application of:

- ► A materially modified modelling structure to that applied last year, including the development of an LFAS market model and integration of the SRAS and LRR optimisation models into a single ancillary services optimisation model, and
- ► Substantially different market rules and processes assumptions to those employed last year, reflecting market developments.

Moreover, the anticipated new entry of significant amounts of large-scale renewable energy into the system means that the environment that is being modelled is very different from that modelled for last year's review. It is difficult to decompose the impacts of these changes when comparing modelling results between last year's to this year's review. However, we note the following:

- ► This year's modelled SRAS cost is lower this year than last year
- ► The average amount of spinning reserve that Synergy needs to provide is also lower than last year
- ► The dynamically calculated load rejection requirement is materially lower than the fixed LRR requirement applied last year

These outcomes are a function of a range of influences, including lower modelled balancing market prices caused by new entry renewable generators, Collie becoming a SRAS capable unit, and the larger amount of non-synergy spinning reserve available through interruptible load.

The arithmetic margin values calculation is effectively the ratio of:

- ► The modelled availability costs, to
- ► The modelled Synergy revenue forgone for provision of SRAS.

Both these quantities decreased from those modelled for last year's review. However, the numerator decreased by a lesser amount than the denominator. Therefore, the margin values have increased.

The modelled LRR cost is lower this year than last year. This is largely a function of Collie becoming an AS capable unit and the substantially lower average LRR requirement resulting from the introduction of the dynamic LRR requirement calculation.

Appendix A Market modelling assumptions

The key market related assumptions applied in the modelling for these ancillary service parameters are summarised in Table 12. Additional information is provided below.

Table 12 Overview of key market related assumptions

Input assumption	Description of data source and value
Energy, Rooftop PV, Behind-the-meter storage, Electric vehicles, Industrial demand	AEMO 2019 WEM Electricity Statement of Opportunities (ESOO) expected scenario. 50% Probability of Exceedance (POE) for peak demand.
New entrant market generators	Information provided via AEMO's review of generator applications in the capacity credit certification process.
Generation retirements	Synergy's announced retirement schedule. Note: the retirement of Muja C Power Station is not within the study period.
Fuel prices (gas and coal)	Contract fuel prices are based on information provided by MPs. Where information has not been provided to AEMO, modelling will use a combination of information provided to inform the 2018 Margin Value determination and market knowledge.
Planned maintenance	A combination of typical maintenance schedules for technology types and specific planned maintenance for unit generators.
Spinning reserve contracts	As determined by AEMO.

A.1 Demand modelling

Demand assumptions used in modelling include annual energy projections, peak demand, the uptake of rooftop solar PV, electric vehicles (EVs) and behind-the-meter battery storage based on the AEMO 2019 WEM ESOO expected scenario. An overview of demand parameters over the forecast period is provided in Table 13 below.

Table 13: Demand parameters

Year	Operational Energy (GWh p.a. sent-out)	Annual peak demand 50% POE (MW)	Installed Rooftop PV Capacity (MW)	Installed Behind-the-Meter Storage Capacity (MW)	Annual energy required by EVs (GWh)
2020-21	18,289	3,813	1,504	68	4.9

A.2 Peak demand

Peak demands are significantly influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The peak demand (and near-peak demand conditions) increases the risk of price volatility, and therefore the magnitude of the peak demand in any given year is a significant factor in determining overall wholesale market pricing trends. EY has used AEMO's published peak demand forecasts representing a 50% probability of exceedance (POE) peak demand level.

The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year and is representative of a statistically likely scenario.

A.3 Rooftop PV

Modelling uses AEMO's expected scenario for rooftop solar photovoltaic (PV) uptake from AEMO's 2019 WEM ESOO expected scenario. The uptake in rooftop PV systems in recent years has been rapid in the WEM, driven by supportive government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs.

A.4 Behind-the-meter storage

EY separately models behind-the-meter (domestic) storage profiles and EV charging profiles to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast by AEMO based on information provided in AEMO's 2019 WEM ESOO expected scenario.

A.5 Electric vehicles

Modelling assumptions use AEMO's expected scenario for electric vehicle (EV) uptake trajectory from AEMO's 2019 WEM ESOO expected scenario. The uptake of electric vehicles is projected to provide a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid. Within the study period, however, the overall contribution from EVs to the annual SWIS operational energy forecast is expected to be less than 0.1%. The impact of EVs on peak demand within the study period is negligible.

A.6 New entrant market generators

The following new entrant market generators are included based on capacity credit certification and a market participant submission during the consultation period. Table 14 provides a summary of the SWIS new entrant list. New entrant renewable projects are assumed to offer all capacity into the balancing market at -$40/MWh to reflect an implicit contracted Large-scale Generation Certificate (LGC) revenue. Revised commissioning dates for new entrant generators have been adopted, where provided by MPs.

Table 14: SWIS new entrants list

Project	Capacity (MW)	Load area	Technology	Capacity factor	Expected start date	Modelled start date
Beros Road Wind Farm	9.3	North Country	Wind turbine	46%	1/11/2019	1/07/2020
Greenough River Stage 2	30	North Country	SAT PV	30%	1/04/2020	1/07/2020
Merredin Solar Farm	132	East Country	SAT PV	30%	1/10/2020	1/10/2020
Yandin Wind Farm	214	North Country	Wind turbine	46%	1/10/2020	1/10/2020
Warradarge Wind Farm	180	North Country	Wind turbine	46%	1/10/2020	1/10/2020

A.7 Thermal generation retirements

The recent announcement of the closure of the Muja C Power Station falls outside of this study period.

A.8 Existing facility gas price

Gas prices for existing facilities will be modelled based on information provided by MPs. Where such information has not been provided to AEMO, the modelling is proposed to use a combination of information provided to AEMO as part of the 2018 Margin Value determination and information available publicly.

A.9 Synergy gas price

Synergy did not provide information to AEMO on gas prices for this year's 2019 Margin Value determination. In the absence of such information, AEMO and EY have considered three options:

1. Rolling over the Synergy gas price assumption from the 2018 review
2. Using a spot gas price consistent with the forecasts undertaken in the 2019-20 Energy Price Limits review.[42] The Energy Price Limits review determined an average spot gas price forecasts reducing to $3.41 per GJ in 2019-20, compared to average spot prices of $4.00 per GJ for 2018-19. This price will not consider the value of any contracted gas procured by Synergy
3. Using a gas price of $6.50/GJ on the basis of publicly reported information.

Note that regardless of the option taken, backcasting will be applied to tune the model by adjusting some input parameters, including the Synergy gas price assumption. The backcasting exercise will effectively identify the Synergy gas price that delivers the minimum deviation from observed history. The Synergy gas price used in the modelling may differ substantially from the pre-backcasting starting point.

AEMO advised EY to apply option 3 above as a starting point for the backcasting exercise. Through the backcasting exercise the best fit gas price for Synergy gas generation facilities was around $3.50/GJ which is considerably closer to the price reported in the Energy Price Limits review.

A.10 New entrant facility gas price

No new entrant gas generators are being modelled during the review period, which negates the requirement to assume a gas price for uncontracted gas supplies.

A.11 Pipeline tariffs

Pipeline reservation fees (capacity reservation) are a sunk cost and do not vary with the level of generator output. The majority of gas generators will have DBNGP T1 access (full haul firm access) and will be required to pay the fixed reservation charges regardless of generation output.

Unless other information is provided by market participants, pipeline tariffs for transport cost are assumed to be 0.13 $/GJ, as at 1 January 2019, which is based on the commodity tariff in the ERA tariff variation found here: https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/tariff-variations.

[42] 2019-20 Energy Price Limits Proposal, page 11. Available here: https://www.erawa.com.au/cproot/20601/2/Energy-Price-Limits-proposal-201920.PDF

However, AEMO has approached generators to confirm if the above is applicable to them, and participants have provided updated transport costs as they have confirmed the full haul T1 reference tariff is not applicable to them.

A.12 Coal prices

Coal prices were initially modelled based on a coal generator's unit fuel costs provided through information requests, or in the absence of data, at $2.60/GJ as per the previous Margin Value review.[43] Through the backcasting exercise coal fuel cost was reduced by 40% for Muja, Collie and Bluewaters to improve alignment with the actual 2018-19 outcomes, as described in section 5.6.2.[21]

A.13 Forced outage rates

EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. The same outage statistics are applied for generators with the same fuel type. A 'mean time to repair' and a 'mean time to fail' value is assigned to each generator in the simulation. A unit on a forced outage is excluded from the balancing merit order. The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within facility.

The capacity factors modelled for wind and solar facilities are based on observed and expected output of the wind and solar facilities modelled, and as such implicitly include the impact of overall facility availability.

A.14 Planned maintenance

Planned maintenance of units throughout the study period is modelled in future years based on available information on scheduled outages from AEMO's maintenance planning schedules (via MT PASA)[44] in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the balancing merit order. This information also includes planned maintenance information received directly from the participants.

A.15 Marginal Loss Factors

Transmission losses occur when electrical energy is transported from generators to the demand centres. Marginal Loss Factors (MLF) apportion the cost of these losses across all participants in the market. They are a scaling factor, normally in the range of 0.9 to 1.1.

Volume weighted loss factors are applied to every generator unit in the WEM based on Western Power's most recent calculation of loss factors[45] for 2019-20. A static loss factor is applied in each trading interval within the study period and applied to generator bidding profiles to determine offers referred to the regional reference node. The regional reference node in the WEM model is set at the

[43] 2018-19 Margin Peak and Margin Off-peak Review, page 22. Available here: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/WA_WEM_Consultation_Documents/2017/Margin/Final-assumptions-report--PUBLIC-v14.pdf

[44] Scheduled outages are submitted to AEMO for use in its projected assessment of system adequacy assessments for short-term and medium-term timeframes. MT PASA refers to this assessment for the medium-term horizon, which is a three year assessment.

[45] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors

Muja 330 kV busbar.[46] For new generator connections that have not been assigned an MLF by Western Power an MLF of 1.000 has been assumed.

A.16 Auxiliary factors

Auxiliary factors account for station auxiliary loads and are used to calculate as-generated values based on sent-out generator values, or vice-versa.

[46] Recent reforms have discussed a move of the regional reference node to a demand centre. However, the timing of this change is not expected to occur within the timeframe being considered for this study.

Appendix B LFAS assumptions

The provision of LFAS is modelled via quantities offered into the LFAS market and dispatched based on a merit order.

Offer quantities and the modelled dispatch priority are derived from analysis of recent market offers for current providers and the information provided by a market participant. This is summarised below in Table 15 and Table 16, and will be reviewed in future years.

For trading intervals from 5:30 AM to 7:30 PM, the LFAS requirement is expected to increase to 116 MW[47] for 2020-21. For modelling purposes, the LFAS offer quantities and the modelled dispatch priority are derived from analysis of recent market offers for current providers and the information provided by a new LFAS market participant.

For trading intervals from 7:30 PM to 5:30 AM, the LFAS requirement is expected to be 70 MW[47] for 2020-21. For modelling purposes, the LFAS offer quantities and the modelled dispatch priority are derived from analysis of historical market offers for current providers when the LFAS requirement was 72 MW, and the information provided by a new LFAS market participant. The use of historical market offers for current providers has been used as this would better reflect the incentives for non-Synergy participation and better aligns with the proposed minimum off-peak LFAS requirement of 70 MW for 2020-21.

Table 15: Offer quantities and dispatch priorities for LFAS up market

LFAS merit order position	Facility code	Quantity (MW) 21:00 – 05:00	Quantity (MW) 05:30 – 16:00	Quantity (MW) 16:30 –19:00	Quantity (MW) 19:30 – 20:30
1	NEWGEN_KWINANA_CCG1	30	30	Does not participate	Does not participate
2	ALINTA_PNJ_U1 and/or ALINTA_PNJ_U2	30 (30MW from ALINTA_PNJ_U1, otherwise 30MW from ALINTA_PNJ_U2 when U1 is on outage)	40 (20MW each from ALINTA_PNJ_U1 and ALINTA_PNJ_U2)	40 (20MW each from ALINTA_PNJ_U1 and ALINTA_PNJ_U2)	30 (30MW from ALINTA_PNJ_U1, otherwise 30MW from ALINTA_PNJ_U2 when U1 is on outage)
3	[Redacted]	Does not participate	Does not participate	40	40
4	SYNERGY	As required to meet any shortfall	As required to meet any shortfall	As required to meet any shortfall	As required to meet any shortfall

[47] LFAS requirements have been estimated by AEMO with available information, but final values will be as documented in the Ancillary Services report for 2020.

Table 16: Offer quantities and assumed dispatch priorities for LFAS down market

LFAS merit order position	Facility code	Quantity (MW) 21:00 – 05:00	Quantity (MW) 05:30 – 16:00	Quantity (MW) 16:30 – 19:00	Quantity (MW) 19:30 – 20:30
1	NEWGEN_KWINANA_CCG1	30	30	Does not participate	Does not participate
2	ALINTA_PNJ_U1 or ALINTA_PNJ_U2	30 (30MW from ALINTA_PNJ_U1, otherwise 30MW from ALINTA_PNJ_U2 when U1 is on outage)	40 (20MW each from ALINTA_PNJ_U1 and ALINTA_PNJ_U2)	40 (20MW each from ALINTA_PNJ_U1 and ALINTA_PNJ_U2)	30 (30MW from ALINTA_PNJ_U1, otherwise 30MW from ALINTA_PNJ_U2 when U1 is on outage)
3	[Redacted]	Does not participate	Does not participate	40	40
4	SYNERGY	As required to meet any shortfall	As required to meet any shortfall	As required to meet any shortfall	As required to meet any shortfall

The provision of LFAS by the Synergy balancing portfolio is sourced from nominated gas turbines and presented in Table 17.

Table 17: LFAS dispatch priority order for Synergy portfolio

[Redacted]

Appendix C Facility-related assumptions

Using blank MS Excel spreadsheets, AEMO requested MPs to provide data on facility-related assumptions. AEMO received responses from 13 out of 14 MPs.

No response was received for the TIWEST_COG1 unit. In this case, previous year's data was used.

In the event that the assumptions were not provided by an MP, EY used assumptions provided for the previous year's review (marked with a yellow background) or from a publicly available source (marked with a grey background). See Section A.9 above in relation to Synergy gas price assumptions. The costs shown below are mutually exclusive.

Synergy provided AEMO with coefficients to produce heat rate curves for each unit based on a quadratic function. Other MPs provided the heat rate curve data as discrete numbers for requested output levels.

The data on facility-related assumptions have been reviewed and used for the backcasting exercise and sensitivity analysis. The results of the back-casting analysis and sensitivity analysis have been used to validate the input assumptions, as per the ERA's recommendation[48], and resulted in changes to the facility-related assumptions where appropriate and justification of changes has been provided in section 5.

Assumptions changed as a result of the backcasting and model calibration exercises have been highlighted with **bold blue font** and previous values have been marked with **red font in square parentheses**.

[48] https://www.erawa.com.au/cproot/20324/2/Determination%20paper%20-%20Margin%20Values%202019-20%20and%20Cost_LR%202019-20%20to%202021-22%20.pdf

Table 18: Facility parameters part 1

[Redacted]

Table 19: Facility parameters part 2

[Redacted]

Table 20: LFAS, SRAS and LRR capability

[Redacted]

Appendix D Planned maintenance periods

Planned maintenance of units throughout the study period is modelled in future years based on available information on scheduled outages from AEMO's maintenance planning schedules (via MT PASA)[49] in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the balancing merit order.

Planned maintenance for unit generators is presented in Table 21. This information also includes planned maintenance information received directly from the MPs.

Table 21: Planned maintenance for unit generators

[Redacted]

[49] Scheduled outages are submitted to AEMO for use in its projected assessment of system adequacy assessments for short-term and medium-term timeframes. MT PASA refers to this assessment for the medium-term horizon, which is a three year assessment.

Appendix E Glossary

Abbreviation / term	Description
AEMO	Australian Energy Market Operator
AEMO 2018 ASR	Ancillary Service Report for the WEM 2018-19, June 2018, AEMO
AEMO 2019 ASR	Ancillary Services Report for the WEM 2019 (June 2019), AEMO
AEMO 2019 WEM ESOO	AEMO 2019 WEM Electricity Statement of Opportunities
AGC	Automatic Generation Control
ERA	Economic Regulation Authority of Western Australia
ERA 2019 Decision	Decision on the Australian Energy Market Operator's 2019-20 Ancillary Services Requirements (12 August 2019), ERA
ERA 2018 Determination	Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year. 31 March 2018. Economic Regulation Authority of Western Australia
ERA 2019 Determination	Ancillary service parameters: spinning reserve margin (for 2019/20) and load rejection reserve and system restart costs (for 2019/20 to 2021/22). Determination (31 March 2019). Economic Regulation Authority of Western Australia
EV	Electric Vehicle
FY	Financial Year
GIA	Generator Interim Access scheme
IPP	Independent Power Producer
LFAS	Load Following Service
LFAS down	Downwards Load Following Service
LFAS up	Upwards Load Following Service
LRR	Load Rejection Reserve Service
Margin Values	Margin_Peak and Margin_Off-Peak
MP	Market Participant
Peak (off-peak)	A peak (off-peak) trading interval occurs between 8:00 AM and 10:00 PM (10.00 PM and 8.00 AM) respectively
PV	Photovoltaics
RC_2018_06 Rule Change	Final Rule Change Report: Full Runway Allocation of Spinning Reserve Costs. 30 April 2019

Abbreviation / term	Description
SRAS	Spinning Reserve Service
SBP	Synergy Balancing Portfolio
SRMC	Short-Run Marginal Cost
STEM	Short-Term Energy Market
SWIS	South West Interconnected System in Western Australia
Synergy SRAS availability payments	Payments to compensate Synergy for provision of the SRAS, conceptually based on the opportunity cost of providing this ancillary service
WEM	Wholesale Electricity Market in Western Australia
WEM Rules	Wholesale Electricity Market Rules

Appendix F LRR: Operational Practice

The following information has been provided by AEMO to summarise the operational practices in relation to the management of LRR:

This information describes how Load Rejection Reserve (LRR) is managed in real-time by AEMO in the South West Interconnected System (SWIS). In particular, the underlying reasons for why LRR is not fully optimised so as to align with the dynamic LRR requirement in operational practice are described in more detail.

Introduction

LRR in the SWIS is manually provisioned and managed by AEMO with generating units from the Balancing Portfolio. In real-time, the LRR requirement is a dynamic value that reflects the largest credible load contingency, as well as adjustments for load relief response and the over-frequency tripping of wind farms.

As at November 2019, the following units in the Balancing Portfolio are capable of providing LRR:

Real-time calculation of available LRR (by unit)

Unit	Available LRR Calculation
[Redacted]	

Provisioning and management of LRR

The provisioning of LRR is based on a merit order, as specified in dispatch guidelines provided by Synergy, but subject to any real-time Dispatch Criteria considerations that require out-of-merit dispatch. Under the merit order approach, the least-cost plant in terms of short run marginal cost (i.e. the coal-fired Muja and Collie units that have already been committed) are dispatched first to provide LRR before more expensive plant (i.e. Synergy's gas-fired units) are dispatched. In the ideal scenario, the LRR requirement is met by LRR provided by units that are also in merit in the balancing market. However, it may be necessary under certain circumstances (e.g. during periods of low load) to dispatch gas-fired units out of merit to provide LRR. In such cases, the theoretically optimal operating point is to dispatch the out-of-merit plant at the lowest possible output above minimum generation to exactly cover any LRR shortfall.

The following table provides the underlying logic for the planning and real-time management of LRR in both the planning timeframe and in real-time:

Dispatch Scenario	Planning (90 MW requirement)	Real-time actions
All coal-fired units online (4 x Muja and 1 x Collie)	In the planning timeframe, no out-of-merit dispatch is required as the LRR planning requirement of 90 MW can be met from LRR provided by the coal-fired fleet.	<u>If LRR availability ≥ Dynamic LRR requirement</u> No action required as there is no out-of-merit dispatch.
		<u>If LRR availability < Dynamic LRR requirement</u> Re-dispatch coal-fired units so that they are above their minimum gross outputs to provide their full quantity of fixed LRR capability. No out-of-merit dispatch is expected in this case.
LRR from coal-fired units online + Synergy cleared LFAS Down ≥ 90 MW	In the planning timeframe, no out-of-merit dispatch is required.	<u>If LRR availability ≥ Dynamic LRR requirement</u> No action required as there is no out-of-merit dispatch.
		<u>If LRR availability < Dynamic LRR requirement</u> Re-dispatch coal-fired units so that they are above their minimum gross outputs to provide their full quantity of fixed LRR capability. If this resolves the issue, then no out-of-merit dispatch is required. Otherwise, re-dispatch other in-merit plant in the Balancing Portfolio to recover any consumed LFAS Down and bring up LRR availability to meet the LRR requirement.

		If the issue persists, consider the following actions: 1. If the LRR shortfall appears to be minor and temporary in nature (e.g. <1 hour), monitor the situation and allow the LRR availability to recover by itself. 2. If the LRR shortfall appears to be structural, large and/or long-lasting, re-dispatch the Balancing Portfolio by starting a gas turbine out-of-merit. When the LRR requirement has been met, consider decommitting the out-of-merit gas turbines, taking into account emerging and real-time dynamics (see notes below).
LRR from coal-fired units online + Synergy cleared LFAS Down < 90 MW	In the planning timeframe, out-of-merit gas turbines may need to be dispatched (e.g. during off-peak times) to make up for the shortfall in the 90 MW LRR requirement.	<u>If LRR availability ≥ Dynamic LRR requirement</u> No action required if all units are in-merit for energy (e.g. during peak periods). Consider decommitting out-of-merit gas turbines, taking into account practical minimum LRR volumes (see above), as well as emerging and real-time dynamics (see notes below).
		<u>If LRR availability < Dynamic LRR requirement</u> In this scenario, the coal-fired units are already providing their maximum LRR capability, and cannot be re-dispatched to provide more LRR. First, re-dispatch other in-merit plant in the Balancing Portfolio to recover any consumed LFAS Down and bring up LRR availability to meet the requirement. If the issue persists, consider the following actions: 1. If the LRR shortfall appears to be minor and temporary in nature (e.g. <1 hour), monitor the situation and allow the LRR availability to recover by itself. 2. If the LRR shortfall appears to be structural, large and/or long-lasting, re-dispatch the Balancing Portfolio by starting a gas turbine out-of-merit. When the LRR requirement has been met, consider decommitting the out-of-merit gas turbines, taking into account emerging and real-time dynamics (see notes below).

In the planning timeframe, the quantity of LRR to be provisioned is based on the forecast load and Market Participant bid data per the following timetable:

Timeframe	Planning actions
Day prior to Trading Day 1330 – 1600	Get forecast system load and balancing bids from all facilities for the next Trading Day. Prepare a preliminary Balancing Portfolio dispatch plan based on forecast system load and balancing bids from all facilities, and send the dispatch plan to Synergy by 4pm (this is a WEM Rules requirement).
Day prior to Trading Day 1830 – 2000	If required, revise the Balancing Portfolio dispatch plan based on Synergy's 4pm balancing bids and the outcome of any communications with Synergy's trading team.
2 hours before commencement of Trading Day 0600 – 0800	If required, make final revisions to the Balancing Portfolio dispatch plan for the Trading Day, based on all Market Participant bids committed for the start of the Trading Day and any adjustments due to system load forecast variations and forced outages.

Notes:

- Major commitment and decommitment decisions (i.e. Muja, Collie and Cockburn) are communicated and agreed between AEMO and Synergy. These are then reflected in Synergy's Balancing Portfolio bids.
- The planned dispatch of SRAS and LRR are calculated using a heuristic rule-based tool based on Synergy's dispatch guidelines.

- Synergy provides a Gas Turbines and Distributed Generation (GTDG) plant program every week, specifying which Pinjar and Kwinana units should be prioritised for operation in the following week.
- AEMO's power system controllers (operating in real time) may need to update the dispatch plan on an ad hoc basis to account for any unforeseen changes, e.g. forced outages, IPP re-bidding up to balancing gate closure, etc.

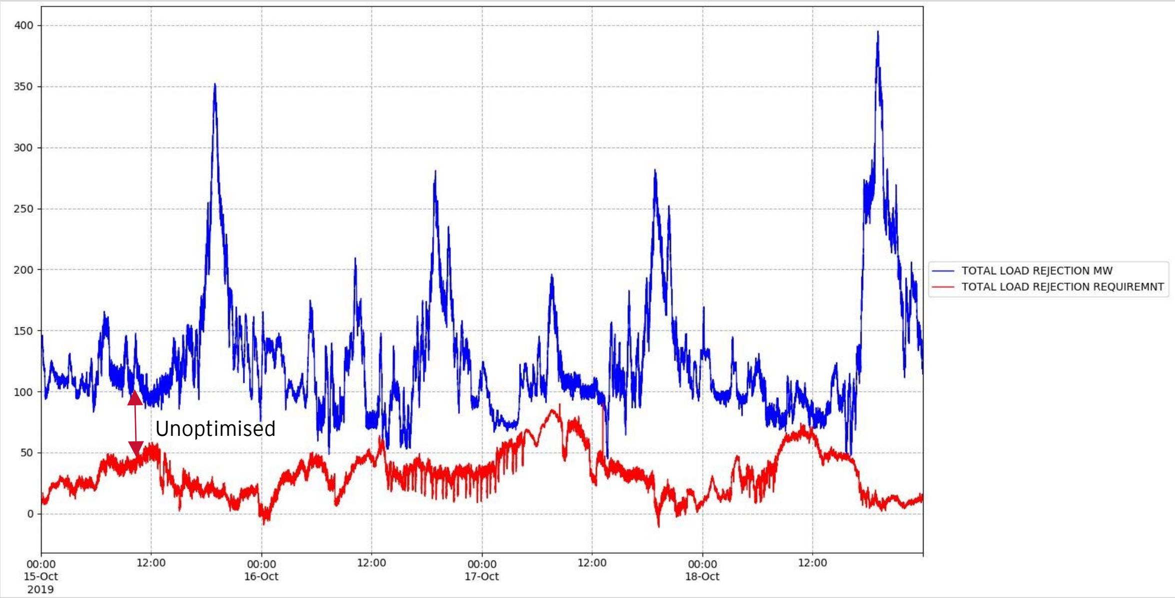
AEMO currently plans for a fixed 90 MW of LRR. This means that Synergy must offer this volume at the market floor price. As discussed earlier, the volume of LRR required to be supplied by out-of-merit gas turbines at the planning stage depends on the number of coal-fired units online and Synergy's expected LFAS Down clearing volumes.

In the next phase of the dynamic LRR trial (should it proceed), AEMO will attempt to plan for an LRR requirement of 90 MW minus forecast load relief. This is nominally the same as AEMO's current process, except that the Metrix system load forecast will be used to determine the forecast load relief.

Optimisation of LRR

The optimal dispatch of generation for LRR is the least-cost mix that meets the LRR requirement. However, there are a number of practical and operational considerations that prevent LRR from being optimally dispatched at all times, owing in part to the inextricable interactions between LRR, load following and the energy market.

For example, consider the following traces showing the available LRR and the dynamic LRR requirement over a 4-day period from 15 to 19 October 2019:



The blue line depicts the amount of available LRR (i.e. carried by AEMO), while the red line shows the dynamic LRR requirement. If the blue and red lines were perfectly aligned, then LRR would be optimally dispatched for the provision of LRR. However, there are persistent gaps between the blue and red lines, which represent "unoptimised" LRR volumes.

The remainder of this document will attempt to articulate the underlying factors that contribute to why there are unoptimised LRR volumes.

Practical minimum LRR volumes

In operational practice, there are minimum LRR volumes that are maintained, irrespective of the LRR requirement. This is primarily due to the following two reasons:

1. Coal-fired power plants: coal-fired units that are online are typically in merit for energy, and therefore normally running well above their minimum generation levels. When the Muja and Collie units are

operating at [Redacted] MW and >[Redacted] MW respectively, then they are able to provide the full amount of LRR, i.e. they have fixed ceiling values for LRR provision above a certain operating output.

Moreover, coal-fired units are normally operated within their [Redacted] mill range and pushing these units to lower outputs by taking mills and/or boiler feed water pumps offline would sacrifice operational flexibility, i.e. the coal-fired units have limited operating ranges with less than [Redacted] mills and [Redacted] boiler feed water pumps in service. This flexibility is desirable to cater for expected daily load movements (e.g. preparation for the morning and evening peaks), as well as unexpected movements in non-scheduled generation and load, especially when the Balancing Portfolio is marginal. For example, with 2 x Muja D and 1 x Collie units online, a minimum quantity of [Redacted] MW of available LRR is provided by the coal fleet. As long as the units stay online, then this minimum quantity of available LRR will not change even if the dynamic LRR requirement is lower.

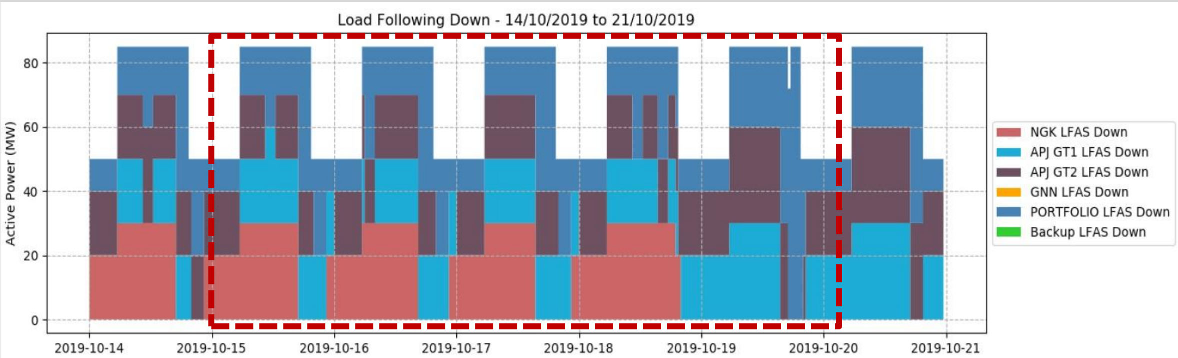
2. LFAS Down: when the Balancing Portfolio is cleared for LFAS Down, this service is provided by the Balancing Portfolio's gas-fired units, and thus all of the available LFAS Down is also counted as available LRR (due to the "spare capacity down" headroom).

   Note that because the Balancing Portfolio is treated as one Balancing Facility under the WEM Rules, individual units do not have basepoints and LFAS Up/Down limits. As a result, the *enablement* of LFAS Down (i.e. the total potential range) is often larger than the quantity that the Balancing Portfolio clears in the LFAS market.

These practical minimum LRR volumes can account for a significant portion of unoptimised LRR volumes. For example, over the period of 4 trading days from 15 to 19 October 2019, LRR was primarily provided by some combination of the following generating units:

- Muja G5 Online for all 4 trading days
- Muja G7 Online for all 4 trading days
- Kwinana GT2 Online for all 4 trading days
- Pinjar GT4 Online intermittently
- Pinjar GT9 Online intermittently
- Pinjar GT10 Online intermittently
- Pinjar GT11 Online intermittently

The Balancing Portfolio was also cleared for between 10 MW and 50 MW of LFAS Down during this period (corresponding to between 14.5 MW and 52.5 MW of LFAS Down enabled):

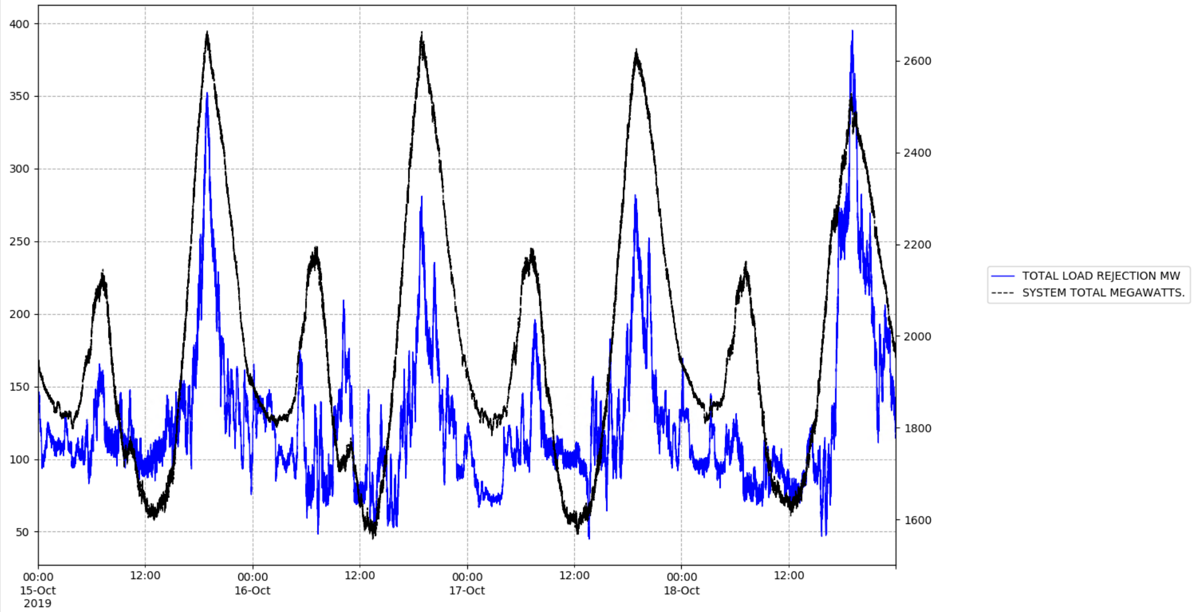


With Muja G5 and G7 in service and operating in their [redacted] mill range, the minimum available LRR from the coal-fired units was [Redacted] MW.

Therefore, on average, the minimum volume of available LRR is the sum of the LRR provided by the Muja units online and the available LFAS Down. During the 4 trading days in the example, the minimum available LRR was roughly between [Redacted] MW and [Redacted] MW on average (it can be instantaneously lower or higher depending on the amount of LFAS Down consumed).

Relationship between available LRR and system peaks

The figure below shows how the available LRR changes relative to system load (over the same 4 trading days):

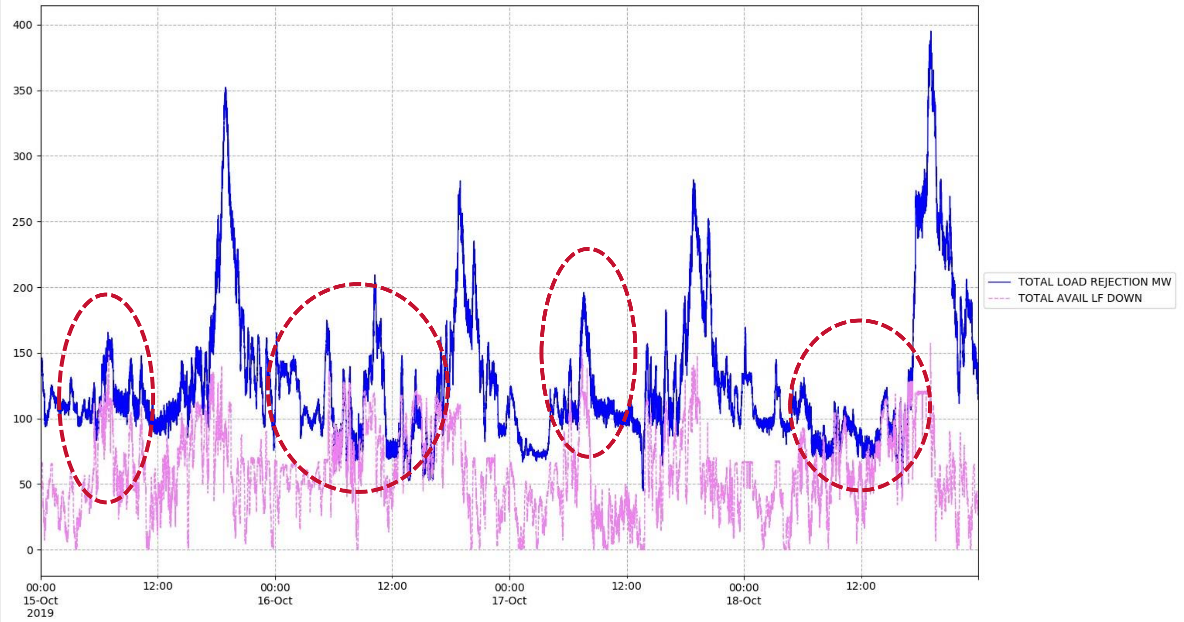


During system load peaks, Synergy's gas-fired units are often in merit and can be dispatched for energy. Since available LRR on Synergy's gas units is calculated as "spare capacity down" (see the table showing *Real-time calculation of available LRR (by unit)*), there tends to be a natural increase in LRR availability when in-merit gas units are dispatched for energy at higher outputs.

As a generalisation of this observation, LRR availability tends to increase whenever Synergy's gas fleet is in merit. Under normal circumstances, this typically only occurs during the morning and evening peaks, but may also occur at other times when balancing prices are high due to weather-related circumstances (e.g. overcast skies and low wind leading to low non-scheduled generator and DER output), or after forced outages of base load plant.

Relationship between available LRR and LFAS usage

The figure below shows how the available LRR changes relative to the availability of LFAS down (over the same 4 trading days):



It can be seen from this plot that increases in available LFAS Down coincide with increases in LRR availability, which helps to explain some of the off-peak spikes in available LRR. This occurs because an increase in available LFAS Down is typically associated with a commensurate decrease/usage of LFAS Up. If the Balancing Portfolio is cleared in the LFAS market, then this means that the Balancing Portfolio's gas-fired units are increasing their output (and thus increasing the amount of available LRR due to the "spare capacity down" calculation as per the table showing *Real-time calculation of available LRR (by unit)*).

Since increases in LFAS Down are usually related to system load volatility, the corresponding spikes in LRR availability are expected to be temporary in nature and would typically disappear within a short period of time. As a result, AEMO's power system controllers (operating in real time) would not actively re-dispatch plant to reduce LRR availability under these circumstances.

Conversely, there are times when LFAS Down is consumed and, as a result, the available LRR reduces commensurately. In such cases, AEMO's power system controllers normally allow the available LRR to fall (without taking action to replenish it), as long as it remains above the dynamic LRR requirement.

Real-time considerations for LRR management

In real-time, AEMO's power system controllers also need to monitor emerging conditions and real-time dynamics, such as:

- Rooftop PV volatility: large cloud bands can cause load swings of more than ±200 MW. As a result, consumption of LFAS Down can cause LRR availability to decline rapidly. If there is inclement weather expected for the whole day, then it may be prudent to maintain additional LRR reserves (above the LRR requirement) to mitigate against rapid changes in LRR availability.
- Metrix system load forecast errors: the Metrix system load forecast is a neural-network based on weather forecasts and other external drivers (e.g. block load outages). Errors in the load forecast (e.g. due to Bureau of Meteorology forecast errors) could lead to over-dispatching of generation, thus leading to LFAS Down consumption and commensurate reduction in LRR availability. If load forecast errors are assessed to be structural for a period of time (rather than temporary changes), then it may be prudent to maintain additional LRR reserves (above the LRR requirement).
- Real-time dispatch engine (RTDE) issues: the RTDE uses a persistence forecast for wind output (i.e. it assumes that wind farm output now will be the same at the next dispatch cycle in 10 minutes' time). This

can cause over- or under-generation when wind farm output is volatile, with cascading impacts to LRR availability. The RTDE is also occasionally subject to IT errors, which can also skew dispatch outcomes.

- Ramp-rates of IPPs: AEMO provides dispatch instructions to IPPs as end-of-interval targets. As a result, IPPs tend to ramp up to their targets as fast as they can (to maximise energy). The Balancing Portfolio, along with LFAS providers, are required to balance system frequency during these ramping events. If there are fast-moving IPPs ramping up to their dispatch targets quickly, then there is a potential for temporary over-generation, and thus a consumption of LFAS Down. As these events are expected to be temporary, it may be appropriate to monitor LRR shortfalls and allow the LRR availability to recover by itself
- Forced outages of in-merit plant: for example, of Muja C/D units, can cause an LRR shortfall, in which case out-of-merit gas turbines would need to be dispatched to meet the LRR requirement.
- Keeping a gas unit online because it is needed later on (rather than decommitting): a gas turbine may have been started out-of-merit to meet an LRR shortfall. The decision to decommit the unit once it is not required for LRR provision also depends on whether the unit may be needed later for energy. AEMO's power system controllers generally follow Synergy's dispatch guideline

Conclusion and future work

In summary, the available LRR carried by AEMO is managed to always be sufficient for system security, but is not always optimised from a cost perspective, primarily because of the following systemic factors:

- Practical minimum LRR volumes due to the operation of coal-fired units in the energy market and gas-fired units in the LFAS market
- Operation of gas-fired units in the energy market during system peaks
- Consumption of LFAS Up/Down leading to transitory increases/reductions in available LRR volumes.

Moreover, with respect to current practice, AEMO's power system controllers manage LRR in real time. LRR is inextricably linked and managed simultaneously with LFAS and SRAS.

There are also other factors that affect the management of LRR that are less systemic and more ad hoc in nature, including:

- An LRR "buffer" is normally carried to account for movements in wind and system load (i.e. due to rooftop solar intermittency). There is no standard value for the LRR buffer, and it is selected based on real-time circumstances (e.g. forecast decline in wind output, high volatility in weather, etc)
- Additional LRR may be carried in preparation for expected load movements (e.g. from system trough to peak or vice versa), where units may be kept online for reasons other than LRR provision, but which may have a downstream impact on available LRR.

Notwithstanding the factors described above, AEMO is investigating opportunities to further optimise the management of LRR in the SWIS without compromising system security, given the current rules and systems, including:

- Forward-looking planning of LRR provision that takes into account load and potentially wind forecasts. Currently, the planning of LRR provision is based on a fixed value (largest credible contingency less minimum load relief), but there is an ongoing trial to progressively transition to a dynamic planning value for LRR.
- Further optimising the LRR requirement based on frequency stability studies, and potentially allowing for greater LRR provision from coal-fired units.

Improvements to the ancillary services framework in the WEM will be delivered through the WEM reform program. AEMO anticipates that these reforms will result in updated systems and processes that allow for the co-optimisation of ancillary services and energy.