Ancillary services parameter review 2019 methodology and assumptions 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.

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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. 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
- The proposed SR_Capacity_Peak and SR_Capacity_Off-peak values (i.e. capacity values for the SRAS) for the purpose of clauses 3.22.1(e) and 3.22.1(f) 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.

Remuneration to Synergy for the provision of LRR is determined by the 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 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.

AEMO in the previous year 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 revised values for 'L' parameter of Cost_LR, 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
- ERA must determine the Cost_LR values for that financial year.

Once determined by ERA, these parameters are used to calculate payments required for Synergy to recover its expected costs of providing SRAS and LRR.

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 a backcasting analysis
- Section 6 details the SRAS and LRR modelling methodology steps
- Section 7 presents a sensitivity analysis
- Appendix A presents general assumptions used in the market modelling
- 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
- Appendix F contains a verification process letter which presents EY's quality assurance process.

[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

2. Frequency AS 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[2] 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 three types of AS. These AS include:

- 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) to ensure that system frequency stays between the range of 49.8 and 50.2 Hz for normal operating conditions.

Frequency deviations arising from single contingency events are managed by the SRAS or LRR where:

- SRAS is used to prevent under-frequency excursions below 48.75 Hz
- LRR is used to prevent over-frequency excursions above 51 Hz.

SRAS is the service of holding a portion of the capacity of a synchronised scheduled generator or interruptible load in reserve so that the facility can respond rapidly to retard frequency drops following the failure of one or more generating works or transmission equipment; and to respond to a sudden shortfall in SWIS supply to prevent involuntary load shedding. The sudden shortfall in supply may result from the loss of a generator or a transmission element connecting generators to the power system. SRAS ensures 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 system load. LRR is the opposite contingency service to SRAS.

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

[2] 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

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 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 for at least 6 minutes or 60 minutes (clause 3.9.7 of the WEM Rules), following a contingency event.[3]

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 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.[4] In summary, the AEMO 2019 ASR explains why AEMO considers that SRAS can be provided only by a balancing portfolio facility or contracted generator. 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)[5] 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 1.

[3] 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.

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

[5] 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 1: LFAS, SRAS and LRR levels approved by the ERA for 2019-20

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 expects there may 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 if the AS contract provides a cheaper alternative to the AS provided by Synergy's registered facilities, or if the AS requirements cannot be met with Synergy's registered facilities.

As per the ERA 2019 Decision, SRAS for FY 2019-20 will be 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 will be provided by Synergy.

No contracts have been procured for LRR historically or in 2019-20. 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 System Management intends to enter into an ancillary service contract, it must:

- ► Seek to minimise the cost of meeting its obligation to schedule and dispatch facilities to meet the ancillary service requirements in each trading interval (clause 3.11.9(a) of the WEM Rules)
- ► Give consideration to using a competitive tender process, unless System Management 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,[6] 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 ERA's approach, 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 are 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 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.

[6] 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 2. A detailed methodology for deriving Margin Values is provided in Section 4.

Table 2: 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 the basis of payments to other SRAS providers. 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' for energising the transmission network and other generators after a system black-out. The 'R' parameter is not considered in this report.

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 3.

Table 3: 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
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'.[7]

A detailed methodology for deriving Cost_LR is provided in Section 4.

[7] 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 developments in the WEM relating to the provision of AS that will impact the financial year 2020-21:

- 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[8].
>
> 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. This will become the largest SWIS generation contingency. This will occur when the combined output of both generators is in excess of the output of the largest single generator. In certain outage conditions, a network fault between Northern Terminal and Neerabup Terminal will also trip Newgen Neerabup. Up to 730 MW generation could be lost.
>
> 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 will now depend on the output of the intermittent non-scheduled generators and in some intervals, will be larger than the largest contingency in previous years. This will increase the quantity of SRAS required in some intervals.

[8] 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

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, AEMO and EY propose to assume that:

- 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. 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 minimum the off-peak time LFAS requirement (7.30 PM to 5.30 AM) is expected to increase 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.[9]

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 are certified for 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 facilities that are certified for both LFAS and SRAS will 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 subsidise generators with output near the top of a block.

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 will be 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 exists under the current 'modified runway' method, allowing generators to offer more of their applicable capacity into the balancing market, thus producing more competitive prices.

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

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 Participant's 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 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[10] to allocate 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 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.

[10] 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

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 influence 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:

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

where:

- $LRRreq$ 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
- $SystemTotal$ 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 not result in this 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, so as to maintain a margin for wind, solar and system load volatility (which occurs in real-time).

EY's proposed 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

Clause 3.18.11A of the WEM Rules specifies the ready reserve as capacity 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. 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. 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.

For the purposes of the AS parameters modelling, EY will apply a reduced capacity factor constraint for the facilities connected under GIA arrangements, where market data is available and will not apply any constraints to the new GIA generators due to the absence of data. This approach will be reviewed in subsequent reviews.

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 spinning 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 will assess the submissions and determine the quantity and the providers of non-Synergy SRAS assumed for AS parameters modelling.

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

3.8 Possible 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 to 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 or at least a distributed energy resource (DER) register, 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),[11] presence of unserved energy (USE)[12] 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. 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.

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

[12] 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.

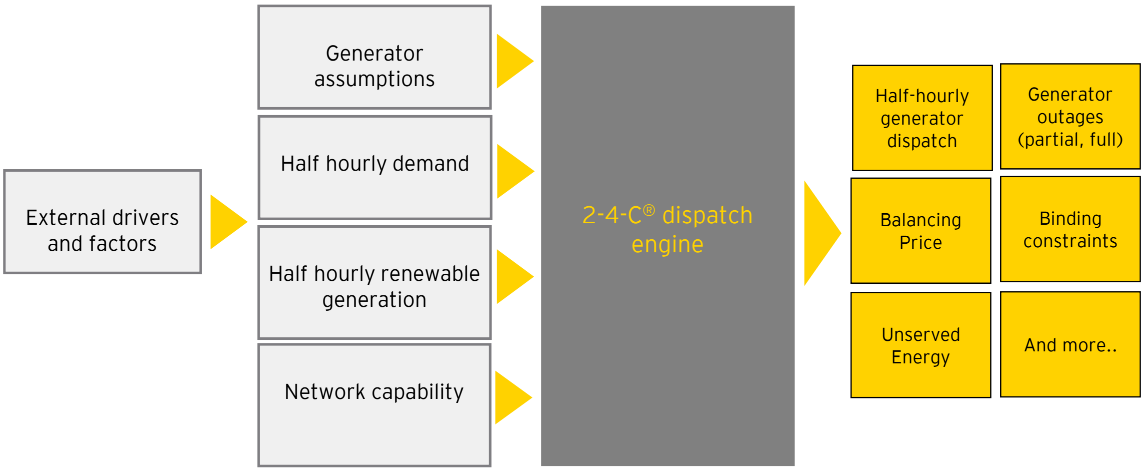


Figure 1: Simplified high level overview of the inputs and outputs to 2-4-C®

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.[13]
- 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).[14] EY's half-hourly profile modelling tools combine these together to produce forecasts of the future half-hourly demand.
- Network capability define 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®.

[13] Generator synchronisation times are not explicitly modelled.

[14] AEMO Electricity Statement of Opportunities

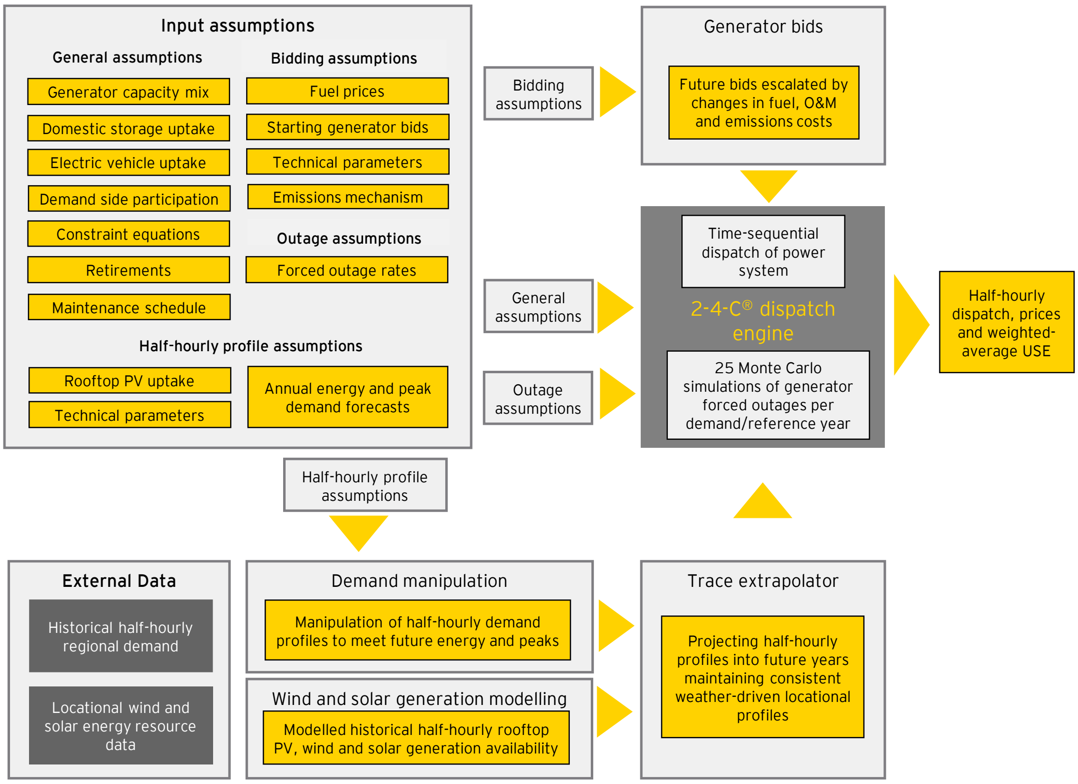


Figure 2: Data flow diagram for the market simulations

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 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.

Table 4 provides a summary of key simulation parameters.

Table 4: Simulation parameters

Simulation parameter	Description
Demand profiles	For each future simulation year the 50% POE values for each 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. 2017-18 reference year is proposed to be used for modelling.
Monte Carlo iterations	On the demand profile we will model 25 Monte Carlo iterations[15] of thermal generator outages (full and partial unplanned outages).
Results	All results will be provided as a weighted average over all 25 iterations. These iterations are made up of a single reference year with a single demand profile with 25 Monte Carlo iterations of forced outage profiles (as described above).
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.

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

5. Backcasting

As part of the review, EY will undertake a backcasting assessment using the information provided to AEMO as part of a market participant information request and using the final modelling methodology developed for this review. This approach allows EY and AEMO to use the most recent information provided to AEMO and consider feedback provided during the public consultation period in the backcasting exercise.

EY will compare the dispatch outcomes simulated from 2-4-C® against the actual outcomes in a historical year. This will involve 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 is used to approximate the typical operating and fuel parameters for each generator.

This section describes the input data proposed to be used for the backcasting exercise for the 2018-19 financial year.

5.1 Backcasting inputs and assumptions

Table 5 summarises the input data and sources proposed to be used in the backcasting exercise.

Table 5: Summary of input data used for the backcasting 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.
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 each generator 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.

Input data	Source	How input data is used in backcast simulation
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.

5.2 Backcast simulation approach

The objective of the backcast is to tune the dispatch model and input assumptions to reproduce historical price and dispatch outcomes using information provided by MPs to derive bidding profiles for each generator.

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

- Set up 2-4-C® to simulate the 2018-19 financial year, using the input data as described.
- Establish an initial offer profile for the provision of LFAS, SRAS and LRR for units that are technically capable of providing the service.
- Establish an offer profile for the balancing market, taking into consideration offer profiles for the ancillary service markets.
- Observe the 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. .

5.3 Analysis of results

EY proposes to analyse the backcasting outcomes for price and dispatch according to a few different metrics, such as annual averages, duration curves and time-of-day averages. These metrics demonstrate the ability of the model to replicate history.

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 behaviour in the system.

5.4 Initial backcasting outcomes 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.

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.

For example, in the 2018 AS parameter review, whilst the dispatch of Collie Power Station and NewGen Kwinana showed reasonable alignment in the backcasting exercise (see Figure 3 and Figure 4), it was noted in the ERA 2019 Decision that the output of Collie and NewGen Power Kwinana did not appear consistent with observed market behaviour. This is because the backcasting exercise was performed before MPs provided information, and before the modelling methodology was finalised.

For this year's review, AEMO and EY have scheduled the backcasting exercise to be performed after finalisation of market participant information and after the finalisation of the modelling methodology.

Figure 3: Load duration curve for Collie power station

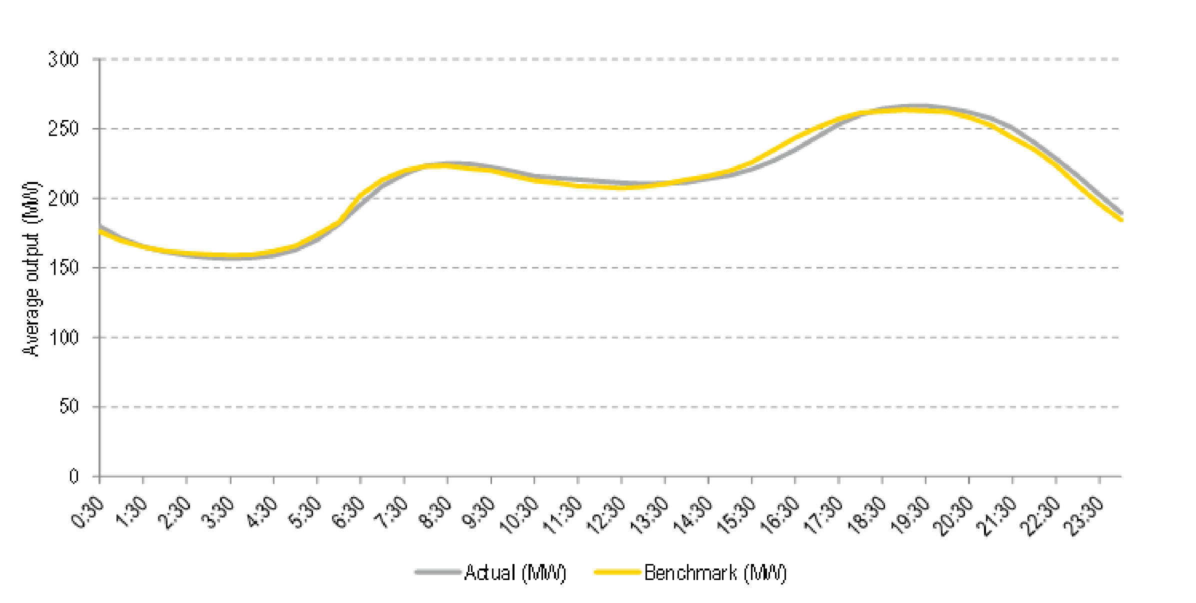
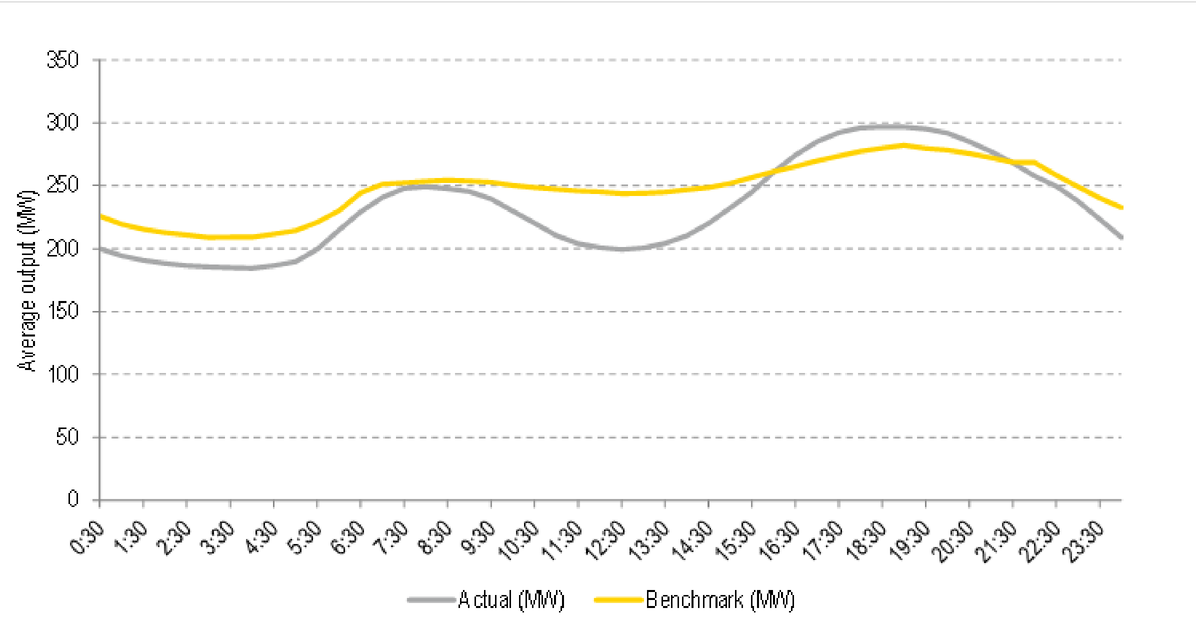


Figure 4: Load duration curve for NewGen Kwinana power station



6. SRAS and LRR modelling methodology steps

In light of Sections 2.6 and 2.7, 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
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 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.

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 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 availability 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.

The optimisation problem for LFAS up requirement in each trading interval t of a financial year, $t = 1,2,3,\ldots,T,\ T$ 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, $\rho_i,\ \{\rho_i \geq 0\}$, 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.

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.

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 ancillary services.

- 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[16]
- 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
- Coal units offer their minimum generation load plus LRR capacity at the floor price to avoid unit cycling.

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.

[16] 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 25 iterations of 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 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.

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 further 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 1).

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 contingency event that would result in the loss of generation has also been accounted for in the modelling. Let:

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

where $G \{G > 0\}$, is the total output, including parasitic load, of the synchronised generation unit that is generating the highest total output in trading interval t, and where Yandin Wind Farm, Warradarge Wind Farm and NewGen Neerabup are treated as a single generation unit, then, the dynamic SRAS requirement net of LFAS capacity contributing to SRAS in trading interval t, S, is given by:

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

where:

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

In line with Section 3.4, EY will model the LRR requirement based on a fixed 90 MW value and also on a dynamically set requirement and assess both outcomes for AEMO to consider in its proposal to the ERA. 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 mix subject to the constraint of the 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).

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

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, $\{J_i \geq Q_i \geq 0\}$.

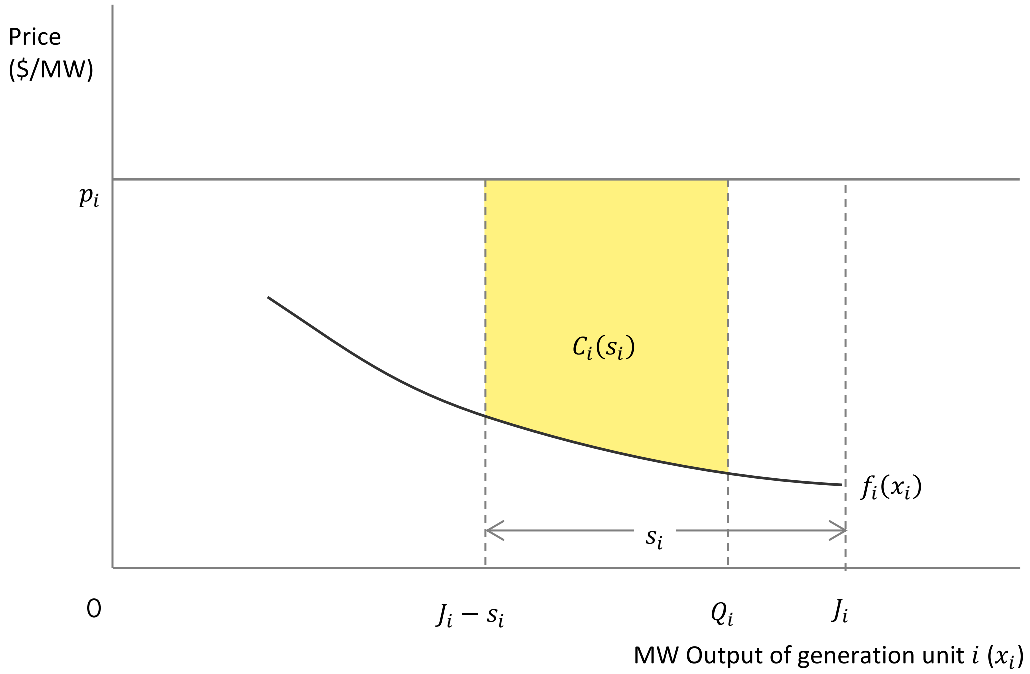
Estimation of $f_i(x_i)$ will entail fitting a polynomial function to heat rate data for each generation unit, then multiplying this function by an assumed per MW half hourly cost that reflects the opportunity cost of fuel plus non-fuel variable operating costs and an estimate of the marginal cost associated 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 5 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 multiplied by the start-up cost of the unit, and then smeared over the number of trading intervals in which a unit is generating for the year. 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 5: 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

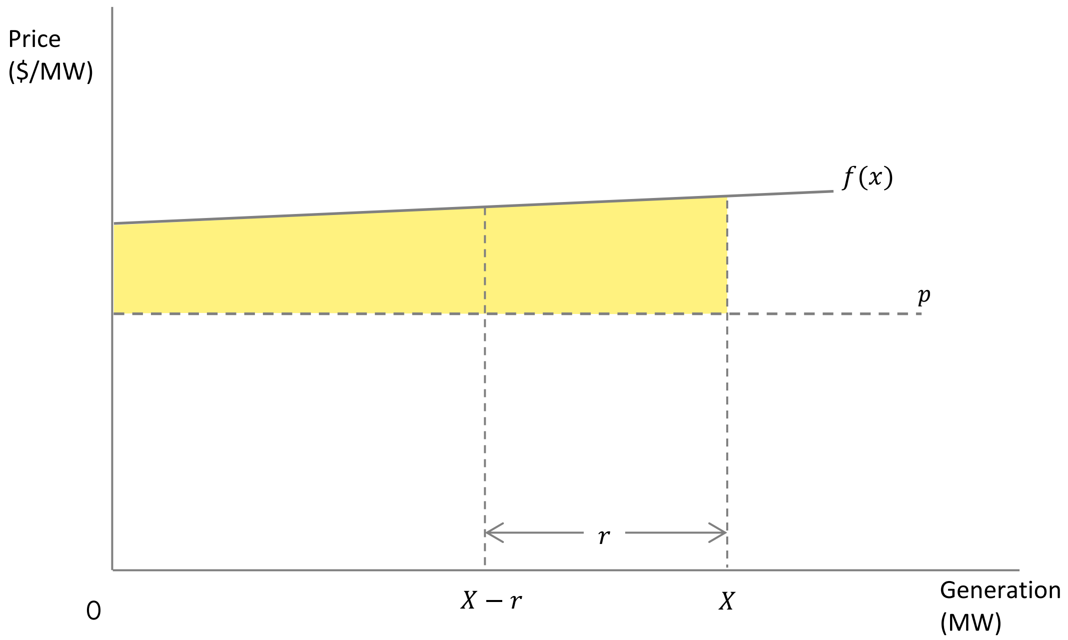
For trading intervals that require generation to be dispatched out of merit to meet the SRAS and/or LRR requirements, the cost incurred by the generator being committed is calculated as the fixed heat rate costs, start-up cost, the costs associated with any energy production plus the estimated marginal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

The costs associated with producing energy is based on facility cost data provided by Synergy. 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 6 for the case where a single unit is required to provide LRR and/or SRAS capacity in a trading interval.[17] 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.

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

Figure 6: Illustrative diagram of the calculation of variable costs for out of merit provision of SRAS or LRR capacity



The fact that the marginal cost function illustrated in Figure 6 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 yellow area in Figure 6 will be allocated to the LRR availability costs and the fixed heat rate and start-up components will be allocated to the SRAS availability 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,[18] 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.[19]

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 such facilities within the

[18] 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

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

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 unit is operating out of merit to provide SR only in a trading interval, then all the associated out of merit costs are allocated to SRAS only
- When 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 SR, then:
    - Allocate half of the net out of merit costs incurred up to the unit's minimum generation level to LRR and the other half to SRAS
    - Allocate all additional net out of merit costs for operating the unit above its minimum generation level 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:

$$
\begin{aligned}
L &= \sum_{t=1}^{T} \sum_{i=1}^{N} C_i(x)\eta_i w_i, \\
C_i(x) &= B_t + \int_0^{X_i} (f_i(x) - p)\, dx, \\
w_i &= \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases}
\end{aligned}
\tag{6}
$$

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 "Cost_L" parameter in the COST_LR 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 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
- Plants on outage (determined in step 6.2 above) will be constrained off in the modelling
- An inequality constraint ensures that the LRR requirement is met in each half hour trading interval
- If the SRAS or LRR requirement is not met in a trading interval, plants 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 for the sake of the ready reserve standard in line with Section 3.5.

EY's SRAS and LRR cost optimisation tool 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 tool solves the following non-linear, constrained minimisation problem conducted for $t = 1,2,3, \ldots T$:

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

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, $\{r_i \geq 0\}$
- ϕ_i denotes assumed maximum SRAS capability of plant i
- θ_i denotes assumed maximum LRR capability of plant i.

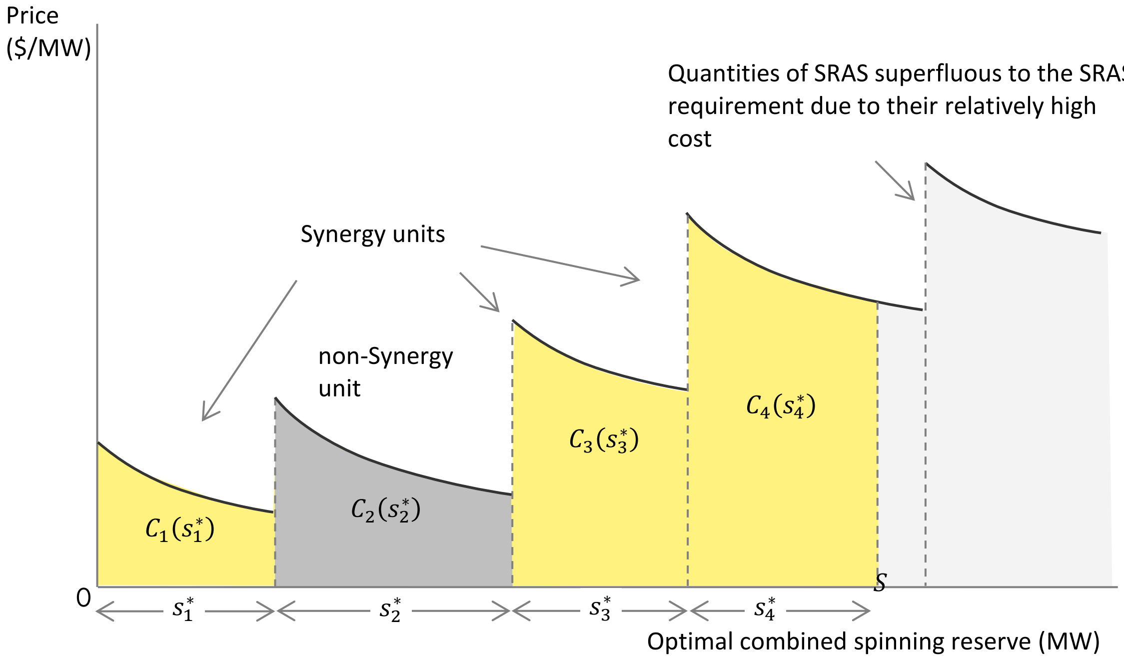
Further constraints ensure generators minimum and maximum generation levels are not exceeded after accounting for plant outages. Expression (7) therefore solves for the least-cost combination of SRAS and LRR quantities from the N generation units, which includes both Synergy and non-Synergy plant, as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

Long-term interruptible load contracts, denoted by M, will be assumed to be 42 MW. Non-Synergy (IPP) contracts, denoted by I, will be the value based on AEMO's determination (see Section 3.7). M is assumed to be zero during the period of the planned outage schedule for intermittent loads on outage.

The optimisation concept for in-merit units is depicted in Figure 7 below, where the marginal opportunity cost or 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 7: 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 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 ($t = 1,2,3,\ldots,T,$ T being the number of trading intervals in the year) is given by Equation (8) below:

$$A_t = \alpha_t \frac{1}{2} p_t(F_t - U_t + H_t - M_t - I_t),$$

$$A_t \geq 0,\ b \geq p_t \geq a, F_t \geq 0, \qquad (8)$$

$$U_t \geq 0,\ H_t \geq 0,\ M_t \geq 0, I_t \geq 0,$$

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
- 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 $i = 1, 2, 3 \ldots, N$, 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.

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, $t = 1,2,3, \ldots, T$, 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:

$$K = F + H.^{20} \tag{11}$$

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:

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

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.

The steps outlined in the preceding sub-sections of this report enable calculation of the variables contained in the equation in Figure 8 below.

Figure 8: 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 in 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:

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

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

$$Q.E.D.$$

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

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:

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

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[21] occurring and
- the LRR response quantity.[22]

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,[23] and the response required from LRR has historically been limited to within a 30 minute trading interval.[24]

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[25] 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.

---

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

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

[23] AEMO provided information to EY regarding over-frequency events on 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.

[24] 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.

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

Table 6: 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)
Load rejection response time (highly conservative)	1 hour or two trading intervals[26]
Maximum balancing price (highly conservative)	$235 / MWh[27] (based on maximum STEM price)
Total energy profits forgone @ maximum balancing price for two trading intervals	$21,150

[26] As indicated in footnote 25 above, the LRR response requirement is for up to 60 minutes, although as indicated in footnote 23 above, the duration of historical load rejection events has fallen short of this requirement.

[27] 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.

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.

EY will consult 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.

Appendix A Market modelling assumptions

The key market related assumptions applied in the modelling for these ancillary service parameters are summarised in Table 7. Additional information is provided below.

Table 7 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. An overview of demand parameters over the forecast period is provided in Table 8 below.

Table 8: 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. 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.

A.5 Electric vehicles

Modelling assumptions use AEMO's expected scenario for electric vehicle (EV) uptake trajectory from AEMO's 2019 WEM ESOO. 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 9 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 9: SWIS new entrants list

Project	Capacity (MW)	Load area	Technology	Capacity factor	Modelled start date
Beros Road Wind Farm	9.3	North Country	Wind turbine	46%	1/7/2020
Greenough River Stage 2	30	North Country	SAT PV	30%	1/10/2020
Merredin Solar Farm	132	East Country	SAT PV	30%	1/10/2020
Yandin Wind Farm	214	North Country	Wind turbine	46%	1/10/2020
Warradarge Wind Farm	180	North Country	Wind turbine	46%	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, which will be an important factor. In the absence of such information, AEMO and EY have considered four options:

- Rolling over the Synergy gas price assumption from the 2018 review.
- Using a spot gas price consistent with the forecasts undertaken in the 2019-20 Energy Price Limits review.28 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.
- Using gas prices recently reported in the media.29 In May 2019, the West Australian reported "Though neither of the parties [the ERA or Synergy] has spoken publicly about the price paid, figures of $6 to $7 a gigajoule have long been bandied around and never denied.". AEMO considered a gas price of $6.50/GJ, with it being the mid-point of the reported range.

AEMO and EY have not identified any additional options based on available data or information but will continue to consider if any other options are available. AEMO currently considers Option 3 as a reasonable approach. AEMO is open to stakeholder feedback on alternative approaches or assumptions.

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 Coal prices

Coal prices will be modelled based on a coal generator's unit fuel costs provided through information requests. In the absence of data, the coal price is assumed to remain constant at $2.60/GJ for the study period as per the 2019-20 Margin Value review[30].

A.12 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

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[28] 2019-20 Energy Price Limits Proposal, page 11. Available here: https://www.erawa.com.au/cproot/20601/2/Energy-Price-Limits-proposal-201920.PDF

[29] https://thewest.com.au/business/energy/sparks-fly-in-energy-row-ng-b881182725z

[30] 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

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.13 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)[31] 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.14 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[32] 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 Muja 330 kV busbar.[33] For new generator connections that have not been assigned an MLF by Western Power, an MLF of 1.000 is proposed to be assumed.

A.15 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.

[31] 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.

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

[33] 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 10 and Table 11 will be reviewed in future years.

A new LFAS entrant has provided confidential assumptions to be modelled, however this has been excluded from the public version of this report.

Table 10: 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 – 20:30
1	NEWGEN_KWINANA_CCG1	20	30	Does not participate
2	ALINTA_PNJ_U1 or ALINTA_PNJ_U2	20	40	40
3	SYNERGY	As required to meet any shortfall	As required to meet any shortfall	As required to meet any shortfall

Table 11: 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 – 20:30
1	NEWGEN_KWINANA_CCG1	20	30	Does not participate
2	ALINTA_PNJ_U1 or ALINTA_PNJ_U2	20	40	40
3	SYNERGY	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 12.

Table 12: LFAS dispatch priority order for Synergy portfolio

Synergy portfolio generator
[Redacted]
[Redacted]
[Redacted]
[Redacted]
[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.

In the event that the assumptions were not provided by an MP, EY used assumptions from the previous year (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.

Table 13: Facility parameters part 1

[Redacted]

Table 14: Facility parameters part 2

[Redacted]

Table 15: 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)[34] 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 16. This information also includes planned maintenance information received directly from the MPs.

Table 16: Planned maintenance for unit generators

[Redacted]

[34] 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
PV	Photovoltaics
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
RC_2018_06 Rule Change	Final Rule Change Report: Full Runway Allocation of Spinning Reserve Costs. 30 April 2019
WEM Rules	Wholesale Electricity Market Rules (1 August 2019)

Abbreviation / term	Description
WEM	Wholesale Electricity Market in Western Australia
SBP	Synergy Balancing Portfolio
SRMC	Short-Run Marginal Cost
SRAS	Spinning Reserve Service
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

Appendix F Verification and quality assurance processes

This appendix aims to provide a clear explanation of the procedures we have developed over a long period of time, to minimise the risk of error in our market modelling engagements.

EY's history as an assurance services firm has furnished us with a deeply entrenched quality assurance (QA) and risk management framework. As a global firm that is subjected to regulatory oversight in many jurisdictions, our QA program meets strict regulatory requirements, supports our clients, and improves project management efficiency and effectiveness. Quality is central to our strategy and to the promise we make to clients – to deliver seamless, consistent, high-quality service worldwide. The principles and processes of EY's global QA program are built into our project delivery and the way we do business, providing a consistent and reliable process. Our aim is to ensure that our work meets or exceeds our clients' needs and that we deliver the level of service quality expected of us.

We have further refined our QA program by instituting strict quality processes and procedures that have been put in place specifically for the current market modelling engagement with AEMO. With a focus on stakeholder engagement in the context of scrutiny of our work by the ERA, and our proposed cross-validation teaming approach to the engagement, we trust that this will give confidence to the quality of our modelling outputs.

The sections of this appendix below will cover the following:

- EY's electricity market modelling QA procedures that will apply to the current engagement
- What EY will do to minimise the risk of errors
- The QA process that will be undertaken subsequent to the discovery of any errors, to ensure correction prior to any inclusion in submissions to the ERA.

Right team

Our QA process starts with our people. As a professional services organisation, our success is dependent on the quality and commitment of our people and how they team together. Attracting, developing and inspiring the best people and promoting a culture that supports them in working together is central to EY's strategy.

Within the QA methodology, our team will focus on the project scope and objectives to identify and address potential functional, technical, process and project management related risks. Areas of potential improvement will be identified early in the process to ensure adequate measures are put in place to avoid additional unexpected project costs, and to continuously enhance project performance.

Market modelling quality control measures

We understand the importance of ensuring that our QA measures allow AEMO to deliver error free proposals to the ERA. We will ensure that the project conforms to AEMO's internal requirements and policies, with a view to the external compliance requirements of the ERA.

The quality control processes employed by EY's market modelling team involve several measures including version control, change log tracking, sense-checking and escalation to managers at critical review points. Detailed measures include:

- **Establishing the modelling approach and framework.** We will actively engage with AEMO in development of the assumptions and methodology with the production of an assumptions Excel workbook and methodology report. This will require one or more internal meetings involving the core delivery team to devise a sound approach to the modelling for each task. The assumptions book is a key central dataset that we refer to often and is always kept up to date.

- **Backcasting.** We will conduct a backcasting exercise as described in Section 5. The benchmarking will focus on generation facility dispatch and WEM balancing market price outcomes (duration and time-of-day profiles). EY will provide AEMO with the outcomes of the backcasting exercise, documenting the approach and assumptions used. This will include the backcasting outcomes and commentary on the alignment with historical observations, providing explanation of the reasons for differences where relevant. This year, EY will use the data provided by MPs in the backcasting exercise.
- **Validation of new methods.** For all custom and new methodologies, we will adopt a thorough testing and experimentation phase in the modelling to ensure the approach works as intended. For new calculations, this may involve performing the calculation with a different tool on a sample of the data, and verifying that the results are the same with both tools.
- **Verification tool.** Before running a market simulation, we use our verification tool that checks for unexpected data in the market simulation database. The tool checks for errors in the setup, ensuring that generator units, stations, regions, technologies, bids, constraint equations, etc. are internally consistent over the modelling horizon.
- **General sense checking.** After running a market simulation, we conduct a thorough analysis of outcomes to ensure it was set up as intended. This includes inspecting annual average outcomes, paying particular attention to outcomes impacted by changes made to the model for the simulation.
- **Sensitivity cross checking.** We will perform sensitivity analysis of modelling outcomes, and on the basis of our professional judgement, will assess the differences between scenarios. In doing so we will work to identify the reasons for those differences. During this process, quality issues as well potential problems with implementation of any new algorithms can be identified.

Engagement Reviews

Work and deliverables are reviewed regularly to confirm that they satisfy client requirements, our quality standard and any external legislative requirements applicable to the engagement. Such reviews do not involve repeating work already performed. Instead, they focus on determining the adequacy of work done and on identifying matters which may have been overlooked.

As advice and opinions can only be given by Partners, Associate Partners and other authorised persons, all interim advice and final engagement deliverables must be reviewed by the person responsible for the engagement, or a person of a higher level.

The engagement partner is responsible for assessing each situation and conducting such reviews where appropriate. EY's Oceania lead of our Valuations and Business Modelling group will provide the second partner review. Other highly experienced team members will provide ongoing technical review throughout the engagement to ensure that any potential for error is identified as early as possible. For this project, additional reviews by certain specialists may also be required and we will discuss resourcing of suitable experts with AEMO if necessary.

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