Ancillary services parameters – Draft assumptions report

PUBLIC VERSION

Australian Energy Market Operator

13 September 2018

Notice

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 a number of market parameters in accordance with the Western Australian Wholesale Electricity Market Rules (the "Services"), in accordance with our Assignment commencing 1 August 2018, under the Master Services Consultancy Agreement entered into by AEMO and EY commencing 5 December 2016.

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

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1. Introduction

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

The ancillary services parameters are:

- The proposed Margin_Peak and Margin_Off-Peak values (Margin Values) for 2019-20 and for the purpose of clause 3.13.3A(a)(i) and 3.13.3A(a)(ii) of the Rules.
- The proposed SR_Capacity_Peak and SR_Capacity_Off-peak values (SR Capacity Values) for 2019-20 and for the purpose of clause 3.22.1(e) and 3.22.1(f) of the Rules.
- The proposed 'L' parameter of Cost_LR, representing the Load Rejection Service Cost for the period from 2019-20 to 2021-22 for the purposes of clause 3.13.3B(a) of the Rules.

This report provides an overview of the assumptions and methods to be used to calculate the values listed above. It should be read in conjunction with EY's *Wholesale Electricity Market modelling and Backcasting Report* dated 29 August 2018, which provides key inputs and outputs to be used for the market modelling project (Project) as well as information on the construct of calibrated bidding profiles[1] to emulate 2017-18 financial year observed dispatch patterns for each generator and balancing prices[2] in the WEM.

In preparing this report, we have used information that has been made publicly available through industry consultations and various industry publications to the extent practicable. We note that the initial set of assumptions have been selected by AEMO based on consultation between EY and AEMO. We note that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that will be modelled.

All prices in this report refer to real June 2018 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July – 30 June) unless otherwise labelled.

1.1 Background

AEMO is required to determine, procure, schedule and dispatch generation facilities to meet the ancillary service requirements in accordance with the Rules. The modelling undertaken here is focused on the following two ancillary services in the WEM:

- Spinning Reserve Ancillary Service (SRAS): which is the service of holding online capacity associated with a synchronised generator, a dispatchable load or an interruptible load in reserve to respond to a frequency event associated with a contingency event involving either the loss of a single generator unit or a single transmission network element.
- Load Rejection Reserve Service (LRRS): which is the service of holding online capacity associated with a synchronised generator or dispatchable load in reserve to respond to a sudden decrease of system load.

In setting the ancillary service requirements, AEMO must consider the ancillary service standards and the SWIS operating standards as defined within the Rules:

- SRAS requirements: AEMO is required to ensure sufficient spinning reserve to cover the loss of 70% of the generator with the highest total output in a particular period. This may be relaxed if AEMO expects that the shortfall will be intermittent in nature and last no longer than thirty

[1] Bidding profiles are a collective set of price-quantity pairs offered into the WEM in Balancing Submissions used in forming the Balancing Merit Order.

[2] Balancing Price as defined in the Rules.

minutes. The SRAS requirement is dynamic and varies from period to period. It is dependent upon generation dispatch outcomes in each period.

- LRRS requirements: The amount of load rejection reserve must ensure that system over frequency is below 51 Hz for credible load rejection events. The largest credible load rejection event is typically set by the loss of a network transmission element (for example, the loss of the 220 kV transmission circuit supplying the Eastern Goldfields region). This value has been determined to be 120 MW by AEMO. This may be relaxed by up to 25% (setting a requirement of 90 MW) by AEMO where it considers the probability of a network transmission fault is rare.

1.2 Provision of ancillary services

There is currently no market for the provision of SRAS or LRRS with Synergy acting as the default service provider. AEMO may contract with individual market participants to provide these services if these services can be provided at a lower cost compared to Synergy.[3] AEMO procured a total of 68 MW through spinning reserve contracts for the 2018-19 year through a long-term interruptible load contract (42 MW) and two short-term contracts with scheduled generators (26 MW in total).[4] No contracts have been procured for LRRS.

Synergy acts as the default provider of LRRS through capable generators in the Synergy Balancing Portfolio. Generators are not explicitly dispatched or enabled to be provide this service,[4] but do so naturally based on their generator output in a period taking into account their minimum stable generation value.

1.3 Ancillary services parameters

The cost of providing these services are borne by market participants through ancillary service settlement calculations,[5] which use administered market parameters determined by AEMO and approved by the Economic Regulation Authority (ERA). The parameters that are the focus of this modelling are outlined in Table 1. These parameters are calculated and proposed to the ERA for use in regulatory determinations.

Table 1: Market parameters to be determined as part of this Service

Parameter	Description
Margin_Peak; Margin_Off-Peak	Margin Values are used to compensate Synergy as the default provider of spinning reserve and represents the opportunity cost associating with making capacity available for the service. Margin Values are applied to the balancing price and the quantity of spinning reserve provided to determine an 'availability payment' to Synergy. Margin Values are calculated for peak[6] and off-peak trading intervals.
SR_Capacity_Peak; SR_Capacity_Off-Peak	SR_Capacity Values are the modelled requirement for Spinning Reserve Service for Peak and Off-Peak Trading Intervals assumed in forming the Margin Values. SR_Capacity values are calculated for peak and off-peak trading intervals and used by AEMO for determining the quantity of spinning reserve service to compensate for providers in accordance with clause 9.9.2(f) of the Rules.
Cost_LR Value	The Cost_LR parameters represents the payment to a market generator for the costs of providing LRRS and the system restart services. Generators that provide LRRS are compensated through the "L" parameter. Generators capable of providing system restart services, that is, are capable of 'black-starting' for energising the transmission network and other generators following a system black out, are compensated through the "R" parameter.

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

[4] 2018 Ancillary Services Report, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf

[5] Clause 3.13 and 9.9 of the Rules.

[6] Peak trading intervals are defined as all trading intervals between 8:00am and 10:00pm.

1.4 Report structure

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

- Section 2 presents a method for the calculation of Margin Values for the 2019-20 financial year
- Section 3 presents a method and discussion of the calculation of the load rejection cost parameter
- Section 4 provides a summary of market related assumptions to be applied in the modelling
- Section 5 provides a summary of facility related assumptions to be applied in the modelling.

2. Margin values calculation method

2.1 Synergy's spinning reserve payment

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

> *"… AEMO must take account of:*
>
> 1. *the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during … Trading Intervals; and*
>
> 2. *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 … Trading Intervals that could reasonably be expected due to the scheduling of those reserves;".*

These clauses of the Rules imply that Synergy's spinning reserve payment should compensate Synergy for the opportunity cost it incurs for being the default supplier of spinning reserve services. 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.

2.2 Synergy's spinning reserve opportunity cost

Synergy's opportunity cost of providing spinning reserve in each trading interval t of a financial year, $t = 1,2,3, \dots, T$, is given by:

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

where:

- A_t is Synergy's spinning reserve opportunity cost for trading interval t
- α_t is a coefficient
- p_t is the balancing price for trading interval t, which is bound by the balancing price floor a and the balancing price ceiling b
- F_t is the spinning reserve requirement in trading interval t
- U_t is the MW capacity necessary to cover the requirement for providing upwards load following ancillary services (LFAS) for trading interval t
- H_t is the MW quantity of non-spinning reserve compliant upwards LFAS capacity in trading interval t; or LFAS capacity which is subject to a contract for spinning reserve in the trading interval t.[7]

[7] AEMO have indicated that Cockburn (COCKBURN_CCG1) and NewGen Kwinana (NEWGEN_KWINANA_CCG1) are to be included in H_t. This is because Cockburn is currently not enabled for spinning reserve and LFAS. NewGen Kwinana's LFAS is included in H_t on the basis that any LFAS capacity dually providing spinning reserve would likely to be reflected in a short term non-Synergy contract and any remaining LFAS capacity is not able to meet the all the requirements for spinning reserve as per clause 3.9.3 of the Rules. The impact of NewGen Kwinana's LFAS not being able to meet all the spinning reserve requirements is that AEMO must dispatch the Synergy Balancing Portfolio to provide spinning reserve for all response periods.

- M_t is the MW capacity of long term interruptible load contracts (non-Synergy) for spinning reserve, with terms that require AEMO to prioritise them for spinning reserve over the use of generation units

- I_t is the MW capacity of short term non-Synergy (i.e. independent power producer) spinning reserve contracts in trading interval t

- The scalar of one half on the right hand side of Equation (1) converts MW values into MWh values for each half hour trading interval.

To summarise Equation (1) in words, Synergy's spinning reserve opportunity cost is defined by multiplying a coefficient against:

- The balancing price, and
- The volume of spinning reserve provided by Synergy units that are not also providing upwards LFAS services.

2.3 Calculating the opportunity cost of providing spinning reserve

The ERA's 2018 Determination paper[8] (2018 Determination) suggested possible improvements to the previous method of availability cost estimation. The ERA indicated that these recommendations "… could be considered by AEMO in future reviews of margin values." (p. 19). As part of the process that led to the development of this Report, EY discussed the 2018 Determination with AEMO in consultation with the ERA's Secretariat. The method developed for this Report has been informed by:

- The ERA's recommendations outlined in Appendix 2 of its 2018 Determination, and
- Further discussions with AEMO and the ERA's Secretariat that have led to a refinement of the recommendations in the ERA's 2018 Determination.

One of the ERA's recommendations relates to estimation of the spinning reserve payment for each Synergy unit on the basis of its efficient opportunity costs. The ERA defined the opportunity cost of spinning reserve for a generation unit (that is able to provide the service) 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 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 its 2018 Determination.

The method we propose to use is based upon Equation A4 provided in the ERA's 2018 Determination. The total opportunity cost, $C_i(s_i)$, for generation unit i providing quantity s_i, $\{s_i \geq 0\}$, of spinning reserve in each trading interval, will be found by solving the definite integral:

$$C_i(s_i) = \int_{Q_i - s_i}^{Q_i} \left(p - f_i(x_i)\right) dx_i, \tag{2}$$

where p is the balancing price, $f_i(x_i)$ denotes the marginal cost of generation unit i as a function of its output x_i, $\{x_i \geq 0\}$, and Q_i, $\{Q_i \geq 0\}$, is the level of output that the unit would sell into the

[8] Economic Regulation Authority, *Determination of the spinning reserve ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year*, Western Australia, March 2018

balancing market if it were not providing spinning reserve. For the purposes of notational clarity the t subscripts have been suppressed in Equation (2).

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

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. The opportunity cost of fuel cost assumption will include relevant pipeline transport costs. Consistent with the ERA's approach to short run marginal cost estimation,[9] we are of the view that the best basis for the opportunity cost of fuel is the spot price, or alternatively the market price for new fuel contracts. The opportunity cost of pipeline capacity may be considered zero if contracted pipeline capacity rights cannot be on sold to third parties in the short run. Our intention is to assume the same per unit cost of fuel/fuel transport that an economically rational market generator would use in making the short run decision whether to generate or not.

The method for calculating the opportunity cost of a generation unit is described graphically in Figure 1 below, which is an adaptation of Figure A5 provided in Appendix 2 of the ERA's 2018 Determination.

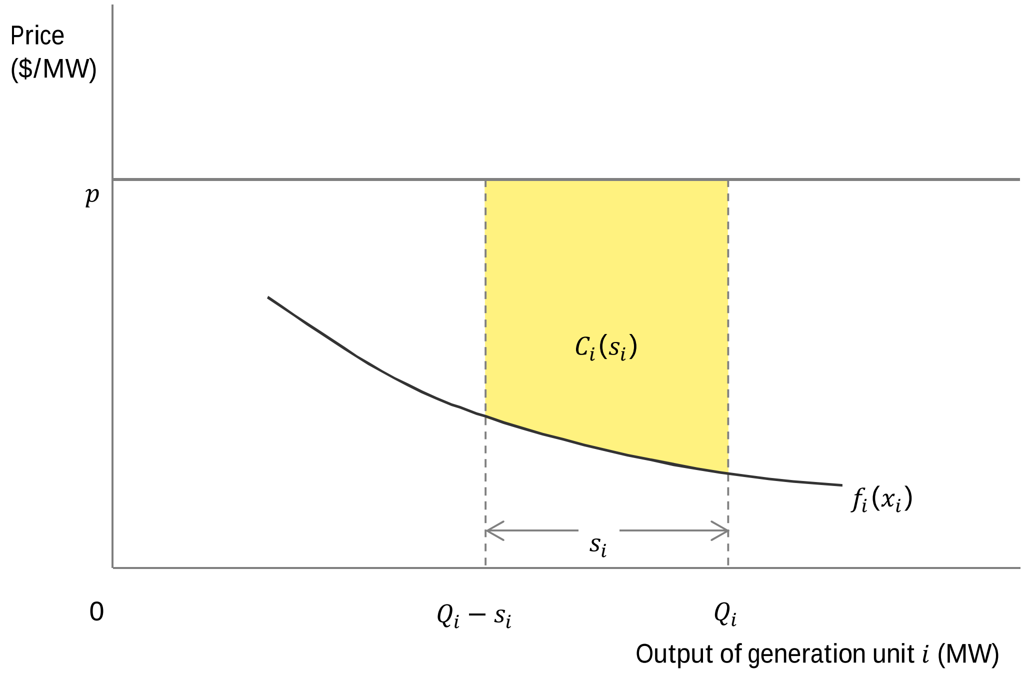

Figure 1: The opportunity cost of a generation unit's provision of spinning reserve

2.4 Modelling of availability cost

In light of Equation (1) and the requirements of the Rules more generally, our proposed method for calculating the availability cost includes the following steps:

1. Preliminary dispatch and generation outage model run. This will provide a preliminary view of the dispatch outcome for the market on the basis of historical balancing merit order profiles. Monte Carlo simulation will be applied to produce multiple time series incorporating unplanned generation outage events. This will be used to simulate dynamic changes to the state of the availability of plant, which will then be used as an input to the 2-4-C market

[9] McHugh, A., *Portfolio short run marginal cost of electricity supply in half hour trading intervals*, Economic Regulation Authority, Western Australia, January 2008

dispatch model (step 2 below). Probabilistic modelling of the contingency and maximum ramp rate conditions of the system will provide an input to determine the required level of spinning reserve in each trading interval. EY's *Wholesale Electricity Market modelling and Backcasting Report* dated 29 August 2018, provides greater detail on the market modelling implementation. 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 spinning reserve.

2. Half hourly forecasting of the least cost mix of upwards LFAS providers. This forecast will be made on the basis of an assumed merit order for the provision of upwards LFAS. The simulation conducted in step 1 above will determine the set of plants available for LFAS provision. The assumed LFAS requirement will be on the basis of AEMO forecasts - this will be an input into the calculation of spinning reserve requirements (step 3 below). This step will also identify the amount of upwards LFAS that is not also eligible to provide spinning reserve.
3. Calculation of a dynamic spinning reserve requirement. The outputs of steps 1 and 2 will be used to calculate the requirement in each trading interval, consistent with clause 3.10.2 of the Rules. See section 2.5 below for more detail on the on the calculation of the dynamic spinning reserve requirement.
4. Half hourly, non-linear optimisation forecast of the spinning reserve mix. This step will solve for the minimum cost mix of all Synergy and non-Synergy generation units that are able to provide spinning reserve in each half hour trading interval of the modelling period. The optimisation will be on the basis of the marginal cost functions of all units available to provide spinning reserve in each half hour trading interval, and will be initially independent of the balancing price. This method will be applied under an equality constraint: the sum of all units' spinning reserve levels will be set equal to the spinning reserve requirement in each half hour (determined in step 3 above). Further constraints will ensure the output of each generation unit providing spinning reserve remains within its rated operational bounds. Plants on outage (determined in step 1 above) will be constrained off in the modelling. See Section 2.6 below for more detail on the spinning reserve cost optimisation method.
5. Half hourly, balancing price modelling. The outputs from steps 1 to 4 will be used as inputs to the 2-4-C dispatch model. The model will be run to provide a balancing price forecast for each trading interval over the modelling period. See EY's *Wholesale Electricity Market modelling and Backcasting Report* dated 29 August 2018 for detail on how this type of modelling is conducted.
6. Half hourly, forecast of the total opportunity cost of spinning reserve. This step will apply the same optimisation algorithm as step 4, but will now include the balancing price derived from step 5 as an input. The minimised objective cost function will give the total opportunity cost of spinning reserve for each half hour trading interval. See Section 2.6 below for more details on the spinning reserve cost optimisation method.
7. Calculation of Synergy's availability cost. Upon completion of step 6, a mathematical filter will be applied to the minimised objective cost function to calculate Synergy's availability payment. See Section 2.7 below.
8. Calculation of SR_Capacity_Peak and SR_Capacity_Off-Peak parameters. The calculation of the average spinning reserve capacity peak trading intervals entails taking the simple average of the dynamic spinning reserve requirement (step 3 above) plus the non-spinning reserve compliant LFAS over peak trading intervals and the average spinning reserve capacity off-peak trading intervals entails taking the simple average of the dynamic spinning reserve requirement plus the non-spinning reserve compliant LFAS over off-peak trading intervals. Details are provided in Section 2.8 below.
9. Calculation of Margin_Peak and Margin_Off-Peak parameters. The outputs of steps 1 to 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. Details are provided in Section 2.9 below.

2.5 Dynamic spinning reserve requirement

Clauses 3.10.2 of the Rules stipulate the principles that the standard for spinning reserve should satisfy as being:

> *"(a) the level must be sufficient to cover the greater of:*
>
> *i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and*
>
> *ii. the maximum load ramp expected over a period of 15 minutes;*
>
> *(b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;"*

For the purposes of modelling, clauses 3.10.2(a) and 3.10.2(b) of the Rules are used to define the dynamic spinning reserve requirement in trading interval t as follows. Let:

$$Y_t = \max[0.7G_t, 0.5\Delta D_t], \quad t = 1,2,3,\ldots T, \tag{3}$$

where:

- G_t $\{G_t > 0\}$, is the total output, including parasitic load, of the synchronised generation unit that is generating the highest total output in trading interval t,
- ΔD_t represents the change in operational demand between trading interval t and trading interval $t-1$,[10]

then, the dynamic spinning reserve requirement in trading interval t, S_t, is given by:

$$S_t = Y_t - U_t + H_t - M_t, \quad t = 1,2,3,\ldots T. \tag{4}$$

2.6 Spinning reserve optimisation

EY's spinning reserve optimisation tool will be used to answer two questions for each trading interval in the forecast period:

1. What level of output will each generation unit that is available to provide spinning reserve operate at to meet the spinning reserve requirement at least overall cost?
2. What is the lowest overall opportunity cost at which the spinning reserve requirement can be met?

Expressing the problem mathematically, the spinning reserve optimisation tool solves the following nonlinear, constrained minimisation problem conducted for $t = 1,2,3,\ldots T$:

$$\begin{aligned} &\underset{m_i \le s_i \le Q_i}{\text{minimise}} \quad \sum_{i=1}^{N} C_i(s_i) \\ &\text{subject to} \quad \sum_{i=1}^{N} s_i = S \end{aligned} \tag{5}$$

where m_i $\{m_i \geq 0\}$, denotes the minimum generation level of generation unit i, N is the number of generation units in the market that are able to provide spinning reserve, and where the operator Σ indicates summation notation; t subscripts have been suppressed for clarity. An outage of any plant

[10] The ΔD_t term is intended to reflect the requirement provided by clause 3.10.2(a)i of the Market Rules , i.e. that spinning reserve should cover "… the maximum load ramp expected over a period of 15 minutes", noting that 2-4-C model has a 30 minute granularity and so cannot model a 15 minute load ramp explicitly.

i in the trading interval is accounted for by setting $m_i = Q_i = 0$, which constrains the spinning reserve quantity s_i to zero.

The optimisation concept is depicted in Figure 2 below, where the marginal opportunity cost spinning reserve for a generation unit is equal to the balancing price minus the generation unit's heat rate based marginal cost function, but horizontally reflected so that costs are given a function of increasing spinning reserve rather than increasing output of energy. In the diagram, the optimisation has resulted in the reserved output from three Synergy and one non-Synergy plant being treated as in-merit.

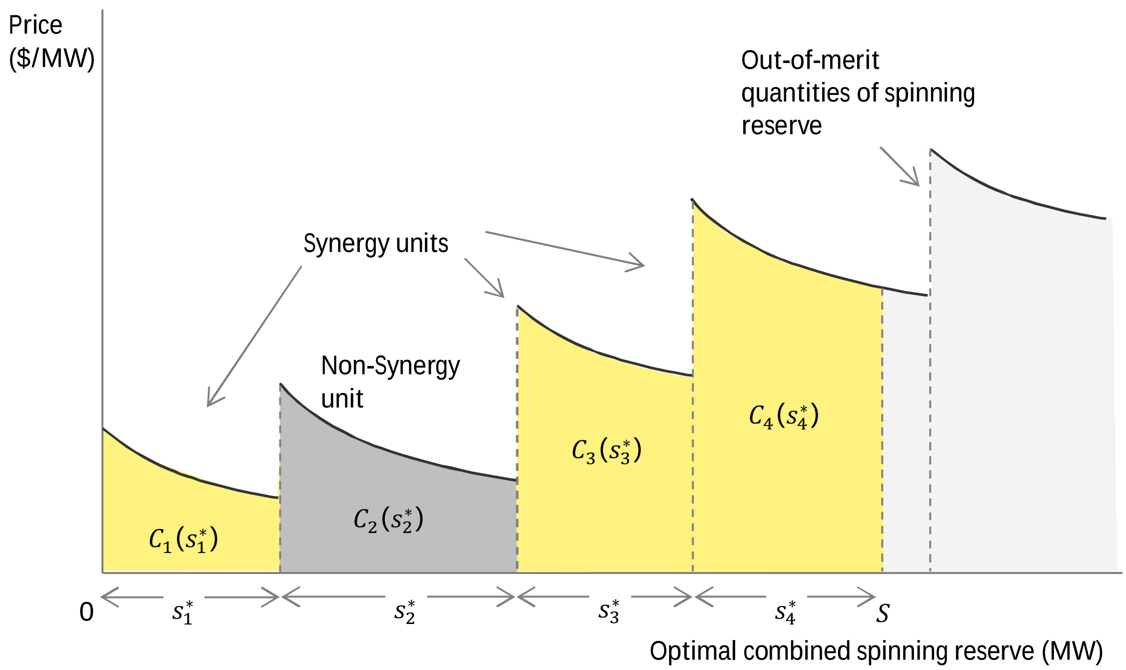

Figure 2: Graphical representation of the spinning reserve optimisation concept

2.7 Calculation of availability cost

Expression (5) solves for the least cost combination of spinning reserve quantities from the N generation units, which includes both Synergy and non-Synergy plant. If we let s_i^* denote the optimal amount of spinning reserve provided by generation units $i = 1, 2, 3 \ldots, N$, i.e. to achieve the least cost solution to Equation (5), then Synergy's availability cost can be calculated as follows:

$$A = \sum_{i=1}^{N} C_i(s_i^*).w_i, \quad w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases} \qquad (6)$$

where w_i is a filter that removes the opportunity cost of non-Synergy plant from the summation of A. Again t subscripts have been suppressed in Equation (6) for clarity.

2.8 Calculation of SR_Capacity_Peak and SR_Capacity_Off-Peak parameters

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

$$R_t = \alpha_t \frac{1}{2} p_t \max[0, K_t - U_t - M_t - I_t], \quad (7)$$

where R_t denotes Synergy's spinning reserve 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_t is solved separately for each trading interval, then letting $R_t = A_t$ it can be shown that:

$$K_t = F_t + H_t.^{11} \quad (8)$$

For the purposes of market settlement, K_t is expressed as two fixed values, one being an average across peak trading intervals for a year and the other being an average across non-peak trading intervals for a year. As such, and in light of Equation (8), AEMO requires the SR_Capacity_Peak parameter to be given by:

$$K_t = \frac{\sum_{t \in P} F_t + H_t}{|P|}, \quad \forall\, t \in P, \quad (9)$$

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

Similarly, for the purposes of market settlement, AEMO requires the SR_Capacity_Off-Peak parameter to be given by:

$$K_t = \frac{\sum_{t \in O} F_t + H_t}{|O|}, \quad \forall\, t \in O, \quad (10)$$

where O is the set of off-peak trading intervals in the year.

2.9 Calculation of Margin_Peak and Margin_Off-Peak parameters

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 its 2018 Determination.

The steps outlined in the preceding sub-sections of this report enable calculation of the variables contained in the equation in Figure 3 below.

[11] To see this, substituting Equations (1) and (7) into $R_t = A_t$ and assuming $R_t > 0$ and $A_t > 0$, we have:

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

$Q.E.D.$

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

The U vector will be the load following up MW requirement

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 MW

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

The p vector will 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 the Market Rules

Figure 3: Representation of the inputs into the regression model

This allows for estimation of the margin peak and margin off-peak parameters, $\hat{\alpha}_t$, by means of regression analysis. EY will adopt a standard approach to regression analysis and reporting, summarised by Figure 4 below.

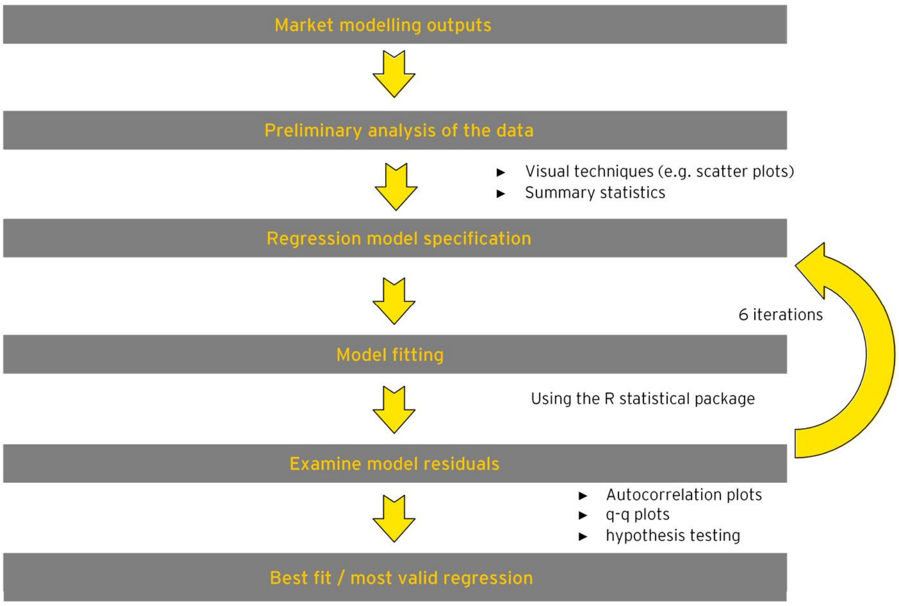

Figure 4: Description of the regression modelling process

As outlined in Figure 4 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 will be:

$$A_t = \hat{\alpha} Z_t + u_t, \quad u_t \sim \mathcal{N}(0, \sigma^2), \tag{11}$$

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:

$$Z_t = \frac{1}{2} p_t.\max[0, K_t - U_t - M_t - I_t]. \tag{12}$$

A potential limitation of the model specification in Equation (12) is that it would require two regressions using truncated time series data, one for estimation of the Margin_Peak coefficient and the other for estimation of the Margin_Off-Peak coefficient. This may result in difficulties in testing for and managing issues related to serial correlation of the residuals. Whether these problems manifest will not be known until the residuals of the model are able to be examined and the validity of the model assessed through hypothesis testing. Considerations in this phase of the regression procedure may include:

- As discussed above, any autocorrelation in the residuals should be corrected for, noting that the regression will be made using modelled time-series data
- The residuals may not exhibit constant variance, the application of robust statistical method may be recommended in this case
- Function form – for this simple regression one choice is between a model specification with an additive error term (optimal for a normal error distribution) or multiplicative (optimal for a log-normal error distribution).

For example, model specification on the basis of a multiplicative error term may be as follows:

$$A_t = \hat{\beta}_1 Z_t {V_t}^{\hat{\beta}_2} u_t, \quad u_t \sim \mathcal{LN}(1, \sigma^2), \tag{13}$$

where V_t is a dummy variable that takes on the value of one when t is a peak trading interval and the number e otherwise. If this specification proves valid, the result will be:

$$A_t \approx \hat{\alpha}_1 Z_t, \qquad \hat{\alpha}_1 = \begin{cases} \hat{\beta}_1 & \text{if } t \text{ is a peak trading interval} \\ \hat{\beta}_1 . e^{\hat{\beta}_2} & \text{otherwise} \end{cases}. \tag{14}$$

This specification would roughly double the degrees of freedom of the regression compared to the case where the problem was broken up into two separate modelling exercises. It would also provide one continuous time series of residuals which would allow for autocorrelation to be tested and corrected for if present.[12]

[12] A key takeaway here is that best empirical model specification cannot be defined ex ante, i.e. regression modelling and examination of the residuals will need to be conducted to determine the appropriate functional form and statistical method.

3. Load rejection cost calculation method

Providers of LRRS are paid through monthly ancillary service settlement calculations determined by AEMO using the Cost_LRD parameter, which is an administered market parameter determined by the ERA for a three year forward looking period.

The Cost_LRD parameter is used for:

- Synergy's ancillary service provider payment calculation, for services associated with LRRS, system restart services and dispatch support services, in accordance with clause 9.9.1 of the Rules, which specifies that for trading month (m):

  > *"the Synergy Ancillary Service Provider Payment(m) = SR_Availability_Payment(m) + Cost_LRD(m) – ASP_Balance_Payment(m)"* [13]

- calculating the cost borne by market participants according to the proportion of their consumption according to clause 9.3.7.

Cost_LRD is specified in clause 3.22.1(g) of the Rules, which states:

> *"Cost_LRD as the sum of:*
>
> *(i) Cost_LR divided by 12 as a monthly amount; and*
>
> *(ii) The monthly amount for Dispatch Support Service.*

Clause 3.13.3B[14] of the Rules specifies that Cost_LR must cover the costs for providing LRRS.

3.1 Load rejection reserve cost

The Rules do not explicitly discuss the methodology or calculation of Cost_LR, except that it must cover the costs for providing the services.

There is currently no market or contract market that exists for this service. LRRS costs are currently borne by Synergy as the default service provider for LRRS as part of its obligation under clause 3.11.7A of the Rules, which requires Synergy to make its capacity to provide LRRS available to AEMO to enable it to meet obligations prescribed in the Rules.

The ERA's 2016 Determination paper[15] (2016 Determination) determined an annual cost for the 'L' parameter of Cost_LR to be $1.4 m for the period from 2016-17 to 2018-19. Prior to 2016-17, the 'L' parameter of Cost_LR has been determined to be zero.

3.2 Calculating the cost of providing load rejection reserve service

LRRS is currently provided by generators in the Synergy Balancing Portfolio only. Although provision for dispatchable loads[16] to provide this service is discussed in the Rules, [17] there are

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[13] SR_Availability_Payment is defined in 9.9.2(g) and ASP_Balance_Payment is defined in 9.9.3A.

[14] Clause 3.13.3B makes reference to clause 3.11.8B of the Rules, but relates to contracts associated with the Dispatch Support Services. This is not relevant for the purpose of this Project.

[15] Economic Regulation Authority, *Determination of the Ancillary Service Cost_LR Parameters for 2016/17 to 2018/19*, Western Australia, March 2016.

[16] Defined in the Rules as a load with a rated capacity of not less than 0.2 MW, through which electricity is consumed where such consumption can be increased or decreased to a specified level upon instruction to do so by System Management and registered in accordance with clause 2.29.5(c).

[17] Clause 3.9.6(b) of the Rules discusses dispatchable loads providing LRRS by increasing consumption rapidly in response to a load rejection event.

currently no registered dispatchable load facilities in the WEM.[18] The Rules also allow for non-Synergy generators to provide this service but no contracts have been provided to date. Our discussion is therefore centred on the cost to Synergy generators in providing LRRS.

Synergy generators that provide LRRS are typically not required to be enabled to provide this service[19], 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 (such as load following and spinning reserve). 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 to do so within the response times specified in the Rules.[20]

As generators are not typically enabled for LRRS, there may be a scenario where the prevailing dispatch of generation in the balancing merit order does not meet the LRRS requirement and generators may need to be committed on out of merit.

Shortfalls in LRRS may be present during periods of low demand (either at night or where rooftop solar PV output is high) causing baseload generators to operate close to or at their minimum stable operating point. During these periods, AEMO may[21] dispatch a generator capable of providing LRRS out of merit to meet the requirement.

In calculating the cost associated with a generator being constrained on to provide LRRS, we therefore consider the cost associated with committing a generator out-of-merit in a trading interval, which is defined by:

$$L_{it} = Startup\_cost_{it} + fuel\_cost_{it} + O\&M\_cost_{it}$$

where:

- L_{it} is the total cost of unit i supplying out-of-merit generation associated with LRRS in trading interval t
- $Startup\_cost_{it}$ includes the opportunity costs of fuel, water, internal power, additional labour and wear and tear directly attributable to the startup of unit i in trading interval t
- $fuel\_cost_{it}$ is the cost of the fuel used in of unit i 's modelled production of electrical energy for out of merit generation in trading interval t
- $O\&M\_cost_{it}$ is the additional variable operational costs associated with the out of merit generation of unit i in trading interval t.

The total cost of providing LRRS for the simulated year, for a set of generator units $i = 1,2,3\ldots,N$, for each of the $t = 1,2,3\ldots,T$ trading intervals in a year, is given by:

$$Cost\_L = \sum_{t=1}^{T}\sum_{i=1}^{N} L_{it}.w_i, \quad w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases}. \qquad (15)$$

[18] http://data.wa.aemo.com.au/#facilities
[19] 2018 Ancillary services Report – Section 2.4
[20] 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 in response to individual load rejection events.
[21] 2018 Ancillary services Report discusses the historic availability of LRRS in the WEM. Table 5 notes that there was 21.4% of the year where the 120 MW LRRS requirement was not met and 6.5% of the year where the 90 MW requirement was not met.

3.3 Constrained on payment mechanism

Market generators in the WEM are compensated through constrained on payments for being dispatched out of merit.[22] Constrained on payments compensate generators for the quantity of energy that is dispatched out of merit, relative to their theoretical energy schedule,[23] at a price that is above the balancing price. This is consistent with the principle that generators that are required to operate, should receive sufficient compensation to meet their short run marginal cost when dispatched.

Constrained on payments are determined by AEMO as part of settlement calculations for each trading interval. Constrained on payments for the Synergy Balancing Portfolio are a function of the portfolio constrained on quantity (PCQ) and a portfolio constrained on compensation price (PCCP) for that trading interval, defined in clause 6.17.5 of the Rules as:

- The PCQ equals the lesser of the maximum energy less the minimum energy (if any), in MWh, which could have been dispatched from the balancing price quantity pair in the Synergy balancing portfolio supply curve and any upwards out-of-merit generation for the Synergy Balancing Portfolio.
- The PCCP equals the loss factor adjusted price that is higher than but closest to the balancing price, taking into account the actual Synergy Balancing Portfolio SOI quantity, less the balancing price.

3.4 Upwards out of Merit Generation

As part of calculating constrained on payments, AEMO is required to determine the upwards out-of-merit generation that has been dispatched from the Synergy Balancing Portfolio.[24]

As part of this calculation, the Rules makes a distinction to what is considered as non-qualifying constrained on generation,[25] which represents the increase in energy due to the dispatch of a network control service contract (NCS) or for the following ancillary services:

- Upwards LFAS enablement
- Upwards LFAS backup enablement, and
- The spinning reserve response quantity.

LRRS does not feature in the definition of non-qualifying constrained on generation and as such, any enablement for purpose of providing load rejection reserve is included in the upwards out-of-merit generation calculated for the purpose of constrained on payments.

3.5 Upwards out of merit generation costs associated with load rejection reserve

In considering the calculation of the upwards out of merit generation costs associated with LRRS for the Synergy Balancing Portfolio, we note that there is an overlap between the constrained on payment mechanism and the cost associated with dispatching the Synergy Balancing Portfolio out of merit to meet the LRRS requirement.

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[22] Out of Merit generation is defined as generation which is dispatched not in accordance with its position in the Balancing Merit Order.

[23] Determined under clause 6.15.1 of the Rules.

[24] Defined in clause 6.16B of the Rules.

[25] Defined under clause 6.17.3(e) or 6.17.5(e) of the Rules.

We note that the only circumstance when the Synergy Balancing Portfolio out-of-merit generation quantities are not eligible for compensation payments is when AEMO determines that a generator has not complied with dispatch instructions.[26]

The Synergy Balancing Portfolio is required to offer into the balancing market on a short run marginal cost (SRMC) basis[27] as part of market power mitigation measures in the WEM.

Notwithstanding the potential for different interpretations of what an SRMC offer could entail,[28] the Rules includes mechanisms to compensate any SRMC associated with start-up and generation that is dispatched out of merit, based on a supply curve that is reflective of the costs of their short-run production.

Therefore, it would appear that the Rules require out of merit generation that is dispatched specifically for LRRS to be compensated through the constrained on mechanism. The outcome of this is that the cost of providing LRRS which may necessitate out of merit dispatch on start-up is recovered through the constrained on payment mechanism during normal market operation. Specifically, the Synergy Balancing Portfolio recovers its short-run marginal costs for energy in the Balancing Market and recovers ancillary services costs in either the LFAS markets, application of margin values in settlements or by contractual mechanisms.

On the basis that this assessment is correct, an appropriate evaluation of upwards out of merit generation associated with LRR is zero. The Cost_LR parameter is therefore limited to consideration of generation that is constrained off (downwards out of merit generation) due to units responding to a load rejection event occurring.

3.6 Constrained off generation as a result of a load rejection reserve event

AEMO is required to calculate the downwards out of merit generation in a trading interval to determine constrained off payments to Synergy's Balancing Portfolio.[29] The Rules excludes load rejection reserve response quantities[30] from contributing to the downwards out of merit generation calculation.[31]

A generating unit may be instructed to curtail its generation output or be disconnected entirely in response to a load rejection event and as a result would incur lost revenue resulting from foregone energy sales at the prevailing balancing price. It would be reasonable to expect that units that respond to a load rejection reserve event should be compensated for providing the service as part of the Cost_LR. We consider energy sales foregone to be a reasonable approximation of the 'L' parameter of Cost_LR to cover the costs for providing this service in accordance with the Rules.

[26] AEMO – Theoretical Energy Schedule FAQ

[27] Clause 7A.2.17 of the Rules.

[28] Market Power Mitigation Mechanisms for the WEM also recommended the retention and support of ensuring suppliers with market power to make energy offers that are SRMC-based, noting the recommendations for clear definition of SRMC and developing a workable definition of SRMC.

[29] Clause 6.16B.2 of the Rules.

[30] Defined in the Rules as an event which causes a facility in the Balancing Portfolio, which System Management has instructed to provide LRRS, to provide a response to that event.

[31] Clause 6.16B.2(b(ii)(3) of the Rules.

3.7 Calculation of Cost_L

We consider that the energy sales forgone as a result of a generator unit being constrained off or curtailed to provide LRRS will be a function of the prevailing balancing price at the time of the load rejection event occurring and the load rejection reserve response quantity.[32]

Load rejection events can occur at any time of the year and is dependent on network outages and the coincident system conditions. However, load rejection events that have led to over-frequency in the WEM are rare[33] and the response required from LRRS has historically been limited to within a 30 minute trading interval.[34]

We consider a rudimentary analysis of the foregone energy sales of a load rejection event in Table 2. We consider 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, under the assumption that AEMO will not decommit a generation unit in response to a load rejection event. We also consider that same analysis based on the observed market average balancing price for the 2017-18 year. We also consider a maximum of two events occurring in a year as reasonable, based on network outage statistics[35] of key bulk transmission circuits.

Table 2: Analysis of a load rejection event occurring at maximum and average energy price for two trading intervals

Input assumption	Description of data source and value
Load rejection response quantity (MW, sustained over time)	120 MW (set by AEMO requirement)
Load rejection response time (highly conservative)	1 hour or two trading intervals[36]
Maximum balancing price (highly conservative)	$302 / MWh[37] (based on maximum STEM price)
Average balancing price (based on observed market data for 2017-18 FY)	$53.35
Total energy sales foregone @ max balancing price for a single event	$36,240
Total energy sales foregone @ maximum balancing price for two events	$72,480
Total energy sales foregone @ average balancing price for a single event	$6,402
Total energy sales foregone @ average balancing price for two events	$12,804

We note that the assessment undertaken in Table 2 would overstate the costs associated with LRRS as it does not take into account the energy contribution required for downwards LFAS enablement

[32] Defined as the quantity of energy reduction, in MWh, provided by a Facility as a Load Rejection Reserve response due to a Load Rejection Reserve Event, but excluding any such contribution that occurred because System Management had instructed the Facility to provide Downwards LFAS Enablement or Downwards LFAS Backup Enablement.

[33] 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.

[34] We note that the LRR response is required across two tranches, 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.

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

[36] As indicated in footnote 34 above, the LRR response requirement is for up to 60 minutes, although as indicated in footnote 33 above, the duration of historical load rejection events has fallen short of this requirement.

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

or backup downwards LFAS enabled as prescribed in the Rules for the trading interval. LFAS enablement is typically also provided by the Synergy Balancing Portfolio.

Notwithstanding the above simplification, the total energy sales that are foregone are still relatively small, with the annual total estimated cost of LRRS to be estimated at $72,480 in the upper bound scenario defined and $12,804 for the typical scenario defined.

If the above assessment is correct and reasonable, we propose that the overall energy sales foregone that could be attributed to Cost_LR is also minor and negligible in the context of the WEM and that Cost_LR is zero.

4. Market related assumptions

The key market related assumptions applied in the modelling for ancillary services are summarised in Table 3 below. Additional information is provided further below.

Table 3 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 2018 Electricity Statement of Opportunities (ESOO) Expected Scenario 50% Probability of Exceedance (POE) for peak demand
New entrant market generators	SWIS renewable planting based on information available via capacity credit accreditation process
Generation retirements	Synergy's announced 380 MW base retirement schedule
Fuel prices	AEMO 2018 Gas Statement of Opportunities (GSOO) - Base fuel price trajectory
Demand response	DSM capacity to be modelled as per AEMO 2018 ESOO with 57 MW in 2018-19 and 66 MW from 2019-20 onwards for the duration of the study period.

4.1 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 AEMO's 2018 ESOO. An overview of these parameters over the forecast period is provided in Table 4 below.

Table 4 Demand Parameters

Year	Operational Energy (GWh p.a. sent-out)	Annual peak demand 50% POE (MW)	Installed Rooftop PV Capacity (MW)	Behind the Meter Storage Energy (MWh sent-out)	Annual energy required by EVs (GWh)
2019-20	18,307	3,914	1,149	63	2.4
2020-21	18,382	3,928	1,303	97	5.8
2021-22	18,506	3,951	1,455	133	12.3

4.1.1 Energy projections

One of the primary considerations when forecasting the electricity market is the future demand for electricity, which is expressed in terms of energy consumption and peak demands. The expected scenario from the AEMO ESOO 2018 (Expected Growth Scenario) has been adopted as the source of electricity demand and energy projection. Figure 5 shows this expected trajectory in annual operational energy consumption (to be met by large-scale generation facilities) for the WEM.

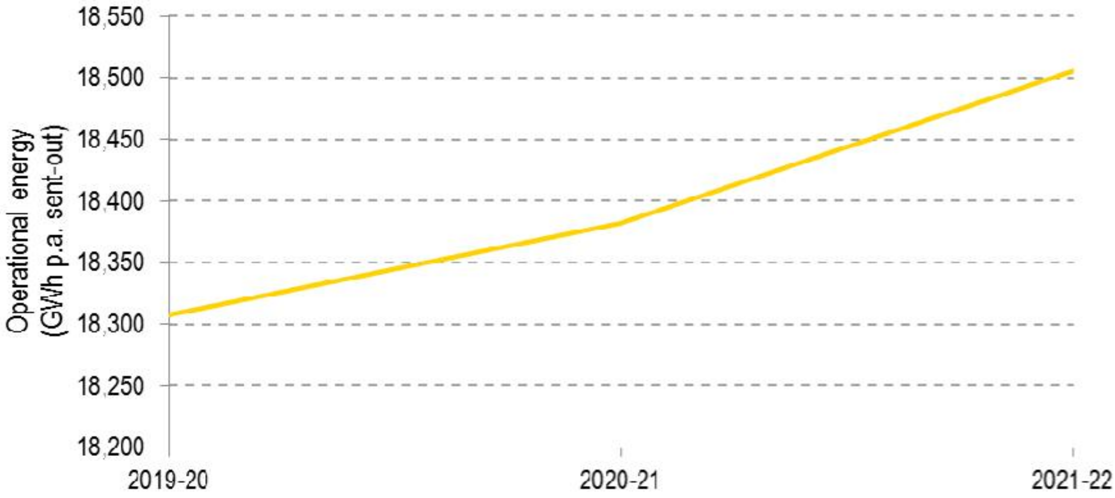

Figure 5: AEMO expected annual regional energy forecast in the WEM

4.1.2 Peak demand

Figure 6 shows AEMO's expected peak demand forecast based on a 50% POE. 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.

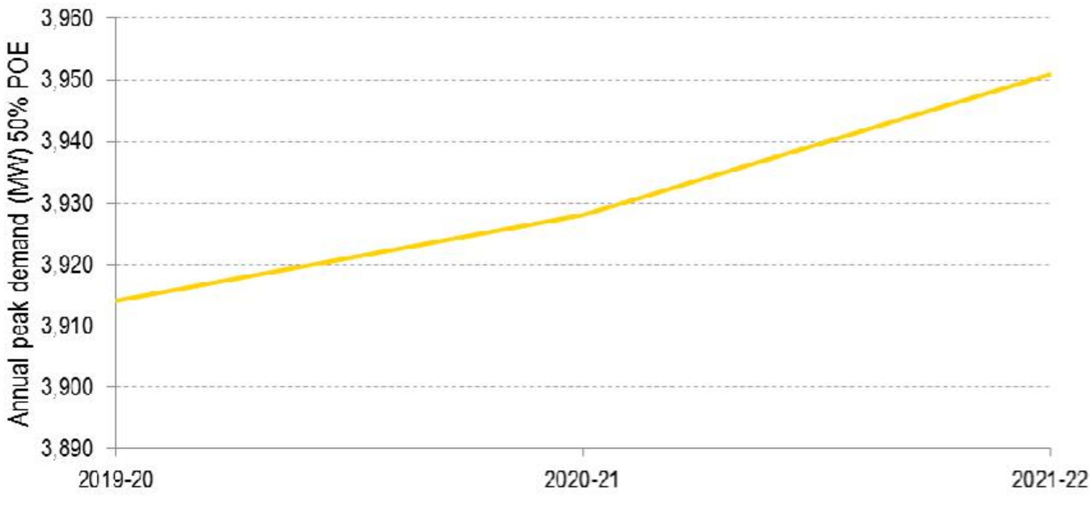

Figure 6: AEMO expected annual 50% POE regional peak demand forecast in the WEM

4.1.3 Rooftop PV

Modelling uses AEMO's expected scenario for rooftop PV uptake from the AEMO ESOO 2018. Figure 7 shows the rooftop PV trajectory used in this scenario. The uptake in rooftop PV systems in recent years has been rapid in the WEM, driven by favourable 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.

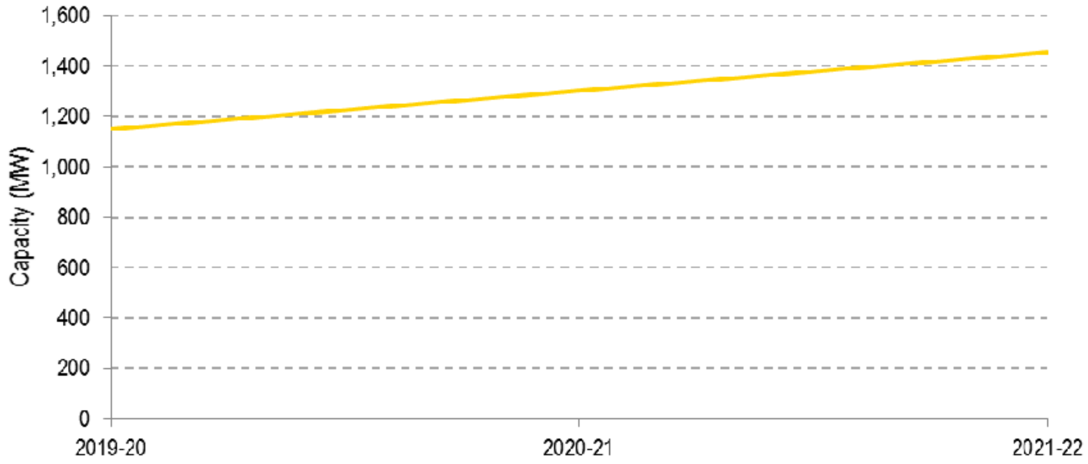

Figure 7: AEMO expected installed rooftop PV capacity forecast for the WEM

4.1.4 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 ESOO 2018. Figure 8 demonstrates this uptake.

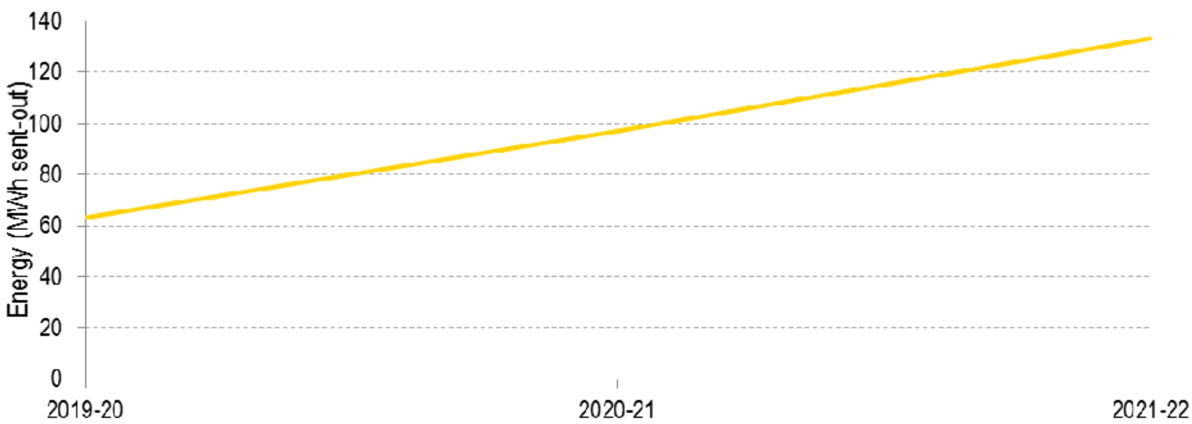

Figure 8: Household battery storage uptake trajectory per region

4.1.5 Electric vehicles

Modelling assumptions use AEMO's expected scenario for electric vehicle (EV) uptake trajectory from the AEMO ESOO 2018. 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%. AEMO expects that the impact of EV's on peak demand to be negligible.[38]

[38] AEMO ESOO 2018

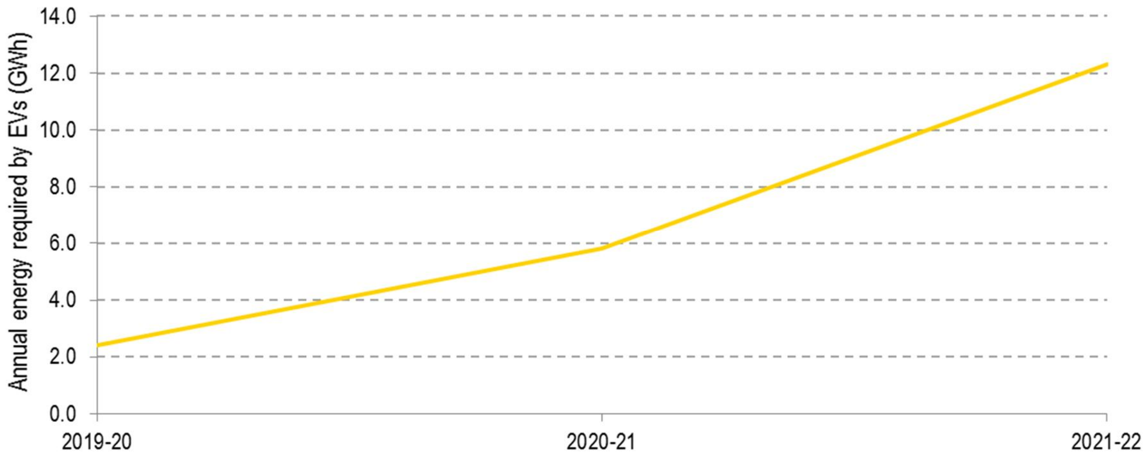

Figure 9: Projected electric vehicle energy consumption

4.1.6 New entrant market generators

The following new entrant generators are included based on capacity credit certification within the study period. Table 5 provides a summary of the SWIS new entrant list. New entrant renewable projects are assumed to offer all capacity into the Balancing Market at a -$40/MWh to reflect an implicit contracted LGC revenue.

Table 5: SWIS new entrants list

Project	Capacity (MW)	Load area	Technology	Capacity factor	Commissioning date
Emu Downs Solar Farm	20	North Country	Single axis tracking (SAT) PV	29%	1 October 2018
Northam Solar Project	10	East Country	SAT PV	27%	1 October2018
Byford Solar/Westgen Solar Farm	30	Kwinana	SAT PV	29%	1 October 2019
Merredin Solar Farm	120	East Country	SAT PV	28%	1 July 2019
Badgingarra Wind Farm	130	North Country	Wind turbine	44%	1 January 2020

4.1.7 Thermal generation retirements

In accordance with the Energy Minister's directive for the retirement of generation capacity in the WEM, Synergy's 380 MW retirement schedule[39] is modelled, presented in Table 6.

Table 6: Thermal generation retirement list

Power Station	Region	Type	Retirement date
Kwinana Gas Turbine 1	Kwinana	Gas	30 September 2018
Muja A	Muja	Black coal	30 April 2018
Muja B	Muja	Black coal	30 April 2018
Mungarra Power Station	North Country	Gas	30 September 2018
West Kalgoorlie Gas Turbine 2, 3	Eastern Goldfields	Gas	30 September 2018

[39] Synergy 380 MW announcement

4.2 Fuel prices

4.2.1 Gas prices

Short-term gas pricing is not considered in the modelling. The assumed gas price trajectory for the SWIS for uncontracted gas supplies is based on publicly available information from AEMO's Gas Statement of Opportunities (GSOO)[40]. As existing gas generators' current gas contracts roll off, it is assumed that these generators will be forced to adopt this price trajectory for their future gas contracts. The gas fuel price trajectory is presented in Figure 10.

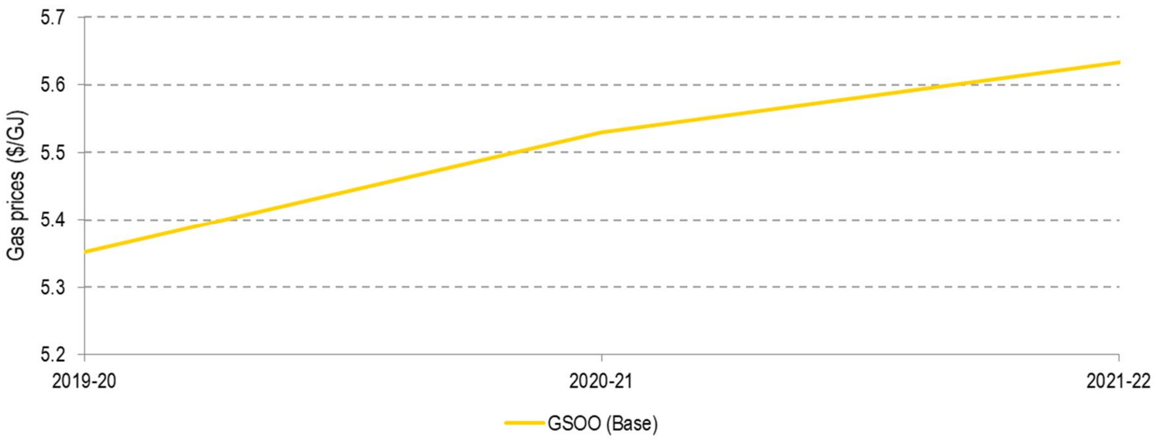

Figure 10: Projected fuel price trajectory

4.2.2 Coal prices

For this Project, the coal price is assumed to remain constant at $2.60/GJ for the study period as per the 2018-19 Margin Value[41]review.

4.3 Demand response

DSM capacity to be modelled as per AEMO 2018 ESOO with 57 MW in 2018-19 and 66 MW from 2019-20 onwards for the duration of the study period.

[40] https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities

[41] 2018-19 Margin Value Review

5. Facility related assumptions

As part of the private consultation process, AEMO and EY is approaching and seeking feedback on the confidential values in Table 7 below.

Table 7: Individual facility level assumptions and data sources

Input assumption	Description
Average heat rates	The amount of energy used by the unit per MWh of energy sent out. Data provided will be used to derive a marginal heat rate curve (e.g. quadratic function, piecewise linear function, etc).
Auxiliary factors	The average percentage of energy generated used to power plant auxiliaries such as fans, motors, feed pumps etc.
Fixed operating and maintenance costs	Plant operational costs that are incurred regardless of energy generated and does not vary with the level of output that the plant produces expressed as $ per MW of nameplate capacity for a year e.g. lighting, fixed scheduled maintenance.
Variable operating and maintenance costs	Non-fuel operational cost that varies with the level of output that the plant produces. Includes wear and tear on plant and equipment directly attributable to the production of output and the value of water and other inputs used to produce electricity output.
Start-up and shut-down costs	Start-up costs include the opportunity costs of fuel, water, internal power, additional labour and wear and tear directly attributable to the start-up. Start-up is defined as the period from zero output to minimum generation. Start-up costs depend on whether a hot start, warm start or cold start occurs, which is determined by the time period elapsed since the plant's previous shut down. Additionally the number of hours that must have elapsed for the plant to be considered to be in each of these states is a part of this information request. Only costs additional to those associated with variable output are to be included. Cost of resources required to shut-down and decommit a plant. This includes costs additional to those associated with variable output, such as fuel, water, operating and maintenance costs of shutting a plant down within a trading interval period. Variable costs incurred when decreasing facility power output to zero should not be included.

Input assumption	Description
Fuel price and transport charge	The best basis for the opportunity cost of fuel is usually the current spot price, or alternatively the current market price for fuel contracts. Pipeline capacity charges should be converted to a $/GJ value (and may be considered zero if they cannot be on sold to third parties). We are seeking the fuel/fuel transport price that a market participant will use when making a decision as to whether to generate or not.
Planned maintenance periods	Planned maintenance periods for the study period.

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