Margin values review for 2019/20

PUBLIC VERSION

Australian Energy Market Operator

13 December 2018

Building a better working world

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 Consultancy Agreement entered into by AEMO and EY commencing 5 December 2016.

The enclosed report (the "Report") provides an overview of the simulation model, the generic data inputs and assumptions used in the delivery of the Services, and the results of the work. The simulation model will form the basis for the outputs produced. It incorporates feedback other stakeholders received during a public consultation process. The modelling methodology and assumptions were agreed in consultation with AEMO.

The Report should be read in its entirety, including the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. The Report has been constructed based on information current as of 13 December 2018 (being the date of completion of this Report), and which has been provided by the Client or other stakeholders, or which is available publicly. Since this date, material events may have occurred that are not reflected in the Report.

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Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

We take no responsibility that the projected outcomes will be achieved, if any. Further, the outcomes are contingent on the collection of assumptions as provided and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided to us or other information sources used.

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Executive Summary

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).

This report provides an overview of the assumptions, methods and results associated with the modelling and calculation of:

- ► 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 (i.e. spinning reserve capacity values) for 2019-20 and for the purpose of clause 3.22.1(e) and 3.22.1(f) of the Rules.

These parameters will be used to determine the quantum of payments required for Synergy to recover their expected costs of providing spinning reserve services for the 2019-20 financial year.

Spinning reserve is required to manage power system security. In the event there is a sudden and unexpected loss of supply due to a credible contingency event, there needs to be sufficient spinning reserve capable generation which has headroom available in its dispatch in order to ramp up very quickly to restore the supply-demand balance. At times, this requires generation capacity to be withheld from the energy market that would otherwise be dispatched to meet the prevailing operational demand. EY's spinning reserve optimisation tool has been applied to answer two questions for each trading interval in the forecast period:

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

The modelling underpinning the calculation of the parameters described above is based on Monte Carlo simulation of the Western Australian WEM using a market dispatch engine that replicates the operation of the real-time market. The model establishes the least cost dispatch pattern of generation to meet the prevailing operational demand, the dispatch pattern is then analysed to determine the least cost means of simultaneously meeting energy balance, load following and spinning reserve requirements. This includes dynamically calculating the prevailing spinning reserve requirement in each half-hourly time interval based on the dispatch of generation and variability in load.

Table 1 provides a summary of the results of the modelling and analysis using the methods and assumptions described in Sections 2 and 3 of the main report. Results are expressed as a simple average across all Monte Carlo generator outage simulations for the key metrics. The Margin_Peak and Margin_Off-Peak values are derived through regression analysis of the Monte Carlo simulation outcomes. Two regressions are conducted, one across peak trading intervals and one across off-peak trading intervals. The functional form for the regression analysis that has been used in this modelling exercise is:

$$A_t = \hat{\alpha}\, Z_t + u_t \quad (1)$$

where A_t is Synergy's spinning reserve opportunity cost for trading interval t, u_t is a random error term with a mean of zero, $\hat{\alpha}$ is the margin values coefficient to be estimated by the regression analysis, and where Z_t is given by Equation (2):

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

In Equation (2):

- 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
- K_t is the SR_Capacity_Peak value if t is a peak trading interval, or is the SR_Capacity_Off-peak value if t is an off-peak trading interval
- U_t is the MW capacity necessary to cover the requirement for providing upwards LFAS for trading interval t
- 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 (2) converts MW values into MWh values for each half hour trading interval.

The annual average availability cost to Synergy of providing the spinning reserve service is calculated to be $10.34 million for the 2019-20 year. The four key parameters show that in this future year it is projected that the spinning reserve requirement will be relatively constant throughout the peak and off-peak periods. In part this is due to and advent of similar day-time and night-time operational demand as rooftop solar PV erodes the daytime operational demand. The Margin_Peak and Margin_Off-Peak quantities reflect the relative opportunity cost to Synergy facilities being a combination of missing potential revenue from the provision of energy into the balancing market, the cost of starting generation facilities that would otherwise not be required, and the savings in fuel and avoided operation and maintenance costs from not actually providing energy into the balancing market.

Table 1: Summary of results

Reporting metric	Units	Modelled outcome	Std error
Weighted average balancing price, peak trading intervals	$/MWh	59.23	0.049
Weighted average balancing price, off-peak trading intervals	$/MWh	47.04	0.037
Arithmetic average balancing price, peak trading intervals	$/MWh	56.48	0.047
Arithmetic average balancing price, off-peak trading intervals	$/MWh	46.08	0.035
Average, annualised availability cost, peak trading intervals	$m	6.91	0.018
Average, annualised availability cost, off-peak trading intervals	$m	3.43	0.015
SR_Capacity_Peak	MW	235.4	0.063
SR_Capacity_Off-Peak	MW	236.4	0.072
Margin_Peak	%	17.32	0.030
Margin_Off-Peak	%	12.92	0.040

The following figure shows the procurement of ancillary services for a single Monte Carlo simulation of generation availability and market dispatch outcomes. The spinning reserve provided by Synergy units is presented twice in the chart for clarity. It is presented as the yellow series in the stack chart which adds up to the prevailing spinning reserve requirement. It is also presented as the blue line on the secondary axis (noting it is the same scale) to more clearly show the quantity of spinning reserve provided by Synergy facilities in this sample. Spinning reserve can be effectively met by interruptible load in addition to generation facilities. The provision of load following ancillary services required to continuously meet the changing supply-demand balance, is generally also considered to contribute to meeting the spinning reserve requirement. In this scenario it is assumed that there is 42 MW of interruptible load (interruptible load), 72 MW of upwards load following ancillary services (LFAS_Up) and 26 MW of contracted generation supply from non-Synergy generation facilities (NS_SR) being 13 MW from each of the two Bluewaters generation facilities.

The resulting provision of spinning reserve by Synergy facilities tends to be approximately 100 MW. It may be lower when the spinning reserve requirement is lower due to a smaller generation facility setting the requirement. It is often higher when contracted spinning reserve capacity from either interruptible load or non-Synergy generation facilities is not available.

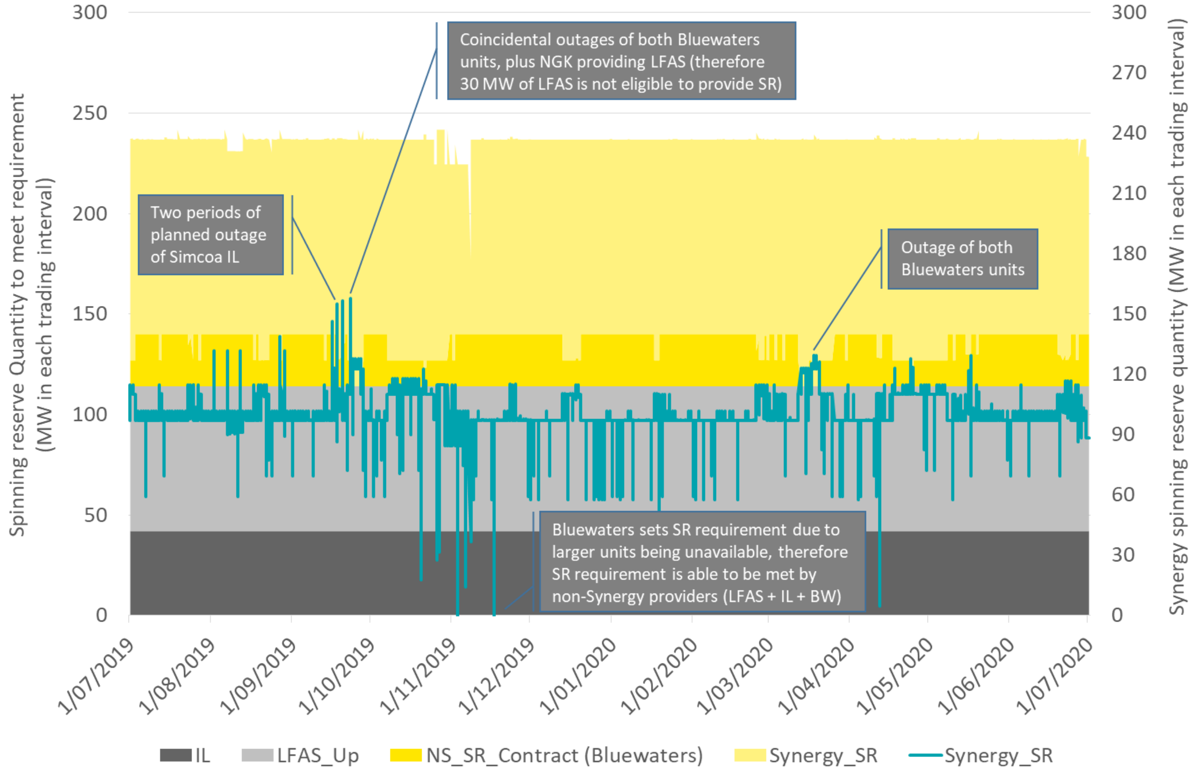

Figure 1: Stack chart for the provision of ancillary services for a single iteration

This is the first year in which EY's electricity market dispatch engine has been employed to calculate margin values. Moreover, in response to the recommendations made by the ERA in their 2018/19 Determination, this year's methodology has changed from those applied in previous years' reviews of margin values. EY is unable comment on the impact of the change in methodology on the margin values calculation.

However, we make the following observations:

- All else being equal, an increase in Synergy's availability costs, on the left hand side of regression Equation (15), will result in larger margin values (and vice versa).
- All else being equal, an increase in the required provision of spinning reserve by Synergy, on the right hand side of regression Equation (15), will result in reduced margin values (and vice versa).
- However, not all else is equal - EY's methodology, developed in the context of the ERA's recommendations, calculates the availability cost with reference to the balancing price. However, the right hand side of regression Equation (15) is also a function of the balancing price. A change in the balancing price will affect both sides of the regression equation in the same direction. This implies that the margin value calculation may be reasonably robust to changes in the balancing price.
- This year's SR_Capacity_Off-Peak value is higher than in previous reviews and is similar to the SR_Capacity_Peak value. EY's modelling finds that NewGen Kwinana operates in most trading intervals of the year, either in the balancing market or in the load following ancillary services (LFAS) markets, and sets the spinning reserve requirement in most trading intervals. An increase in the SR_Capacity_Off-Peak increases the required provision of spinning reserve by Synergy for off-peak trading intervals, relative to availability costs. This will result in lower margin values for off-peak trading intervals than would otherwise be the case.
- EY's estimation of the 2019-20 availability cost is 39% lower than that calculated for the 2018-19 year. If all other variables in the margin value calculation were held constant, a reduction in availability cost of 39% would see a reduction in margin values of approximately 39%.

1. Introduction

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

This report provides an overview of the assumptions, methods and results associated with the modelling of 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.

These parameters will be used to determine the quantum of payments required for Synergy to recover their expected costs of providing spinning reserve services for the 2019-20 financial year.

Our report includes an overview of the submissions received during the consultation that followed AEMO's publication of the Draft Assumptions Report dated 13 September 2018. A summary of how feedback has been considered and incorporated is provided in Section 1.4 below.

In preparing this report, we started with an initial set of assumptions and methods selected by AEMO in consultation with EY. The assumptions and methods have since been updated on the basis of stakeholder submissions and new information received during the public consultation process. 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 have been modelled.

All prices in this report refer to real June 2018 dollars unless otherwise stated. All annual values refer to the financial 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 spinning reserve service requirement in accordance with the Rules. The spinning reserve service is the service of withholding a sufficient collective capacity of synchronised generators and interruptible load ready to respond to a sudden decrease in generation or a sudden increase in system load. Spinning reserve is made available to respond to a frequency event, or avoid involuntary load curtailment, associated with a contingency event involving either the loss of a single generator unit or a single transmission network element which would result in significant loss of supply from multiple generators.

In setting the spinning reserve service requirement, AEMO must consider the ancillary service standards and the SWIS operating standards as defined within the Rules. In practice, the spinning reserve contingency is a function of the total output of the highest output generation unit synchronised to the SWIS in each half hour trading interval.

Generation capacity reserved to meet the LFAS upwards requirement, which is currently set at 72 MW, is counted as contributing to the spinning reserve requirement where the LFAS is provided by Synergy facilities or by non-Synergy facilities which are also registered and contracted to provide spinning reserve.[1] The spinning reserve requirement may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes, and may be further relaxed by up to 100% to the extent that spinning reserves are exhausted after their

[1] AEMO notes the following: The WEM Rules provide a structured framework for AEMO to procure ancillary services. Synergy are the default provider for all ancillary services under clause 3.11.7A of the WEM Rules. Despite the reference to LFAS contribution to spinning reserve in clause 9.9.2(f) of the WEM Rules, AEMO considers that it may only procure spinning reserve from a non-Synergy market participant under clause 3.11.8 of the WEM Rules. This is consistent with the requirement in clause 3.11.10 for AEMO to report certain matters regarding ancillary service contracts to the ERA.

activation, this being an outcome that is preferable to involuntary load shedding. In such situations reserve levels must be fully restored as soon as practicable. Despite this provision in real-time market operations, for the purpose of the modelling and calculations, generation will be appropriately scheduled to meet all ancillary services requirements at all times in which it is theoretically possible to do so.

1.2 Provision of spinning reserve ancillary services

Spinning reserve is required to manage power system security. In the event that there is a sudden and unexpected loss of supply due to a credible contingency event, there needs to be sufficient spinning generation that has headroom available in its dispatch in order to ramp up very quickly to restore the supply-demand balance. At times this requires generation capacity to be withheld from the energy market, which would otherwise be dispatched to meet the prevailing operational demand.

There is currently no centralised market exchange for the provision of spinning reserve, with Synergy acting as the default service provider. AEMO may enter into an ancillary service contract with a rule participant, other than Synergy, if the ancillary services contract provides a less expensive alternative to ancillary services provided by Synergy's registered facilities, or if the ancillary service requirements cannot be met with Synergy's registered facilities.[2] Current independent power producer (IPP) contracts include 26 MW of spinning reserve from the two Bluewaters units. In addition, AEMO has contracted 42 MW of interruptible load from Simcoa. This review has assumed that these contracts will be present in 2019/20.

Synergy acts as the default provider of spinning reserve through generators that are capable of providing the service in the Synergy Balancing Portfolio. Generators must be explicitly configured to provide the service, and offers into the balancing market must be managed by the participant to ensure enough generator output is withheld from the balancing market for sufficient spinning reserve to be made available to AEMO.

1.3 Ancillary services parameters

The cost of providing the Spinning Reserve service is borne by market generators through ancillary service settlement calculations,[3] which use administered market parameters proposed by AEMO and determined by the Economic Regulation Authority (ERA). The parameters that are the focus of the modelling, which is the subject of this report are outlined in Table 2. These parameters are calculated and proposed to the ERA for use in annual regulatory determinations.

[2] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services; clauses 3.11.8 and 3.11.8A of the Rules.
[3] Clause 3.13 and 9.9 of the Rules.

Table 2: Market parameters to be determined as part of this assessment

Parameter	Description
Margin_Peak; 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 Spinning Reserve, for the opportunity cost of 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, which reflects the opportunity cost. Currently, the margin values are the basis of payments to other spinning reserve providers. Margin Values are calculated for peak and off-peak trading intervals.[4]
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 are 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.

1.4 Public consultation process

As part of a broader ancillary services parameter review, which has included an assessment of load rejection service costs,[5] a period of public consultation was conducted based on the following published reports.

- **2018 WEM Modelling and Backcasting Report - 31 August 2018.** This report provides an overview of the model that is used to simulate generator dispatch in the WEM, including key inputs used in the modelling and outputs derived from it. The report also outlines the results of the backcasting exercise to demonstrate modelling outputs against historical dispatch and balancing price outcomes.
- **2018 Draft Assumptions Report – 14 September 2018.** This report detailed the facility and market related assumptions that were, at the time the report was published, proposed for EY's market modelling of the Margin_Peak, Margin_Off-Peak, SR_Capacity_Peak, SR_Capacity_Off-Peak and the Cost_LR values. AEMO invited submissions from market stakeholders seeking feedback on facility parameters and market related assumptions provided in the report.

AEMO and EY also conducted a stakeholder consultation workshop held on 18 September 2018, where EY presented both reports to attendees. EY outlined the assumptions and the key modelling methodologies to be employed.

One public submission[6] and one confidential submission was received.

Table 3 and Table 4 summarises the key points made in relation to market related parameters and methodology.

[4] Peak trading intervals are defined as all trading intervals between 8:00am and 10:00pm and Off-Peak Trading Intervals are defined as all Trading Intervals between 10.00pm and 8.00am.

[5] Final Report on Load Rejection Ancillary Service Costs.

[6] Ancillary services parameters

Table 3: Key points raised in public submissions

Submission topic	High level summary of feedback received
Constrained payments	A submission was received relating to market settlement calculations and constrained payments.
Unit commitment	A submission was received regarding unit commitment decisions.
Modelling future balancing prices	A submission was received regarding modelling future balancing prices and the impact of dynamic changes in the market currently (fuel cost, behind the meter solar, large scale new entrant).
New entrant generator list	Updates to the indicative in-service dates for renewable projects were provided.
Gas prices	A submission was received related to the assumed gas price trajectory.
Gas transport charge	A submission was received related to fixed reservation charges for gas transport infrastructure.

Table 4: Submissions received as part of the public consultation period for market related assumptions

Market generator	High level summary of feedback received
Synergy	Synergy also submitted that unit commitment decisions and the costs associated with them are key factors in determining its cost of providing ancillary services. Synergy submitted that "…when deciding which facilities to commit, the generation business will take a forward view of load forecasts over a number of days." Synergy considers that the modelling methodology should consider a 2-4 day unit commitment technique. Synergy also submitted a concern that the proposed modelling method assumed future balancing merit order profiles will reflect past profiles, citing key changes in fuel costs, and outputs from distributed solar and new large-scale renewable generators in the future. Synergy considers that accounting for these variables through historical balancing offers and future load forecasts will not capture their impacts on how ancillary service requirements are met.
Confidential	A market participant submitted that the AEMO 2017 GSOO low gas price forecast should be adopted for the modelling exercise, and that adoption of the expected gas price forecast over-estimates fuel cost inputs for gas generators, noting that spot market prices have been lower in recent years. A submission was also received asserting that only pipeline commodity fees should be included in the formulation of generator offer curves and that reservation fees are a sunk cost. The submission also considers that it is important for AEMO to determine the proportion of generators that use spot transportation and apply a weighted average transport price for specific generators.

1.4.1 Outcome of consultation

In its consideration of the above points, EY in consultation with AEMO concluded that on:

- **Unit commitment**, EY considered implementing a unit commitment algorithm in the model, but upon consultation with AEMO came to a view that this would be impractical for the following reasons:
    - The extensive back-casting exercise conducted for the purposes of model calibration and demonstration of calculation accuracy did not employ a unit commitment algorithm. Our back-cast achieved relatively accurate balancing price and generation dispatch outcomes when compared against historical market outcomes. Specifically, our back-casting tested duration curves for price and generation by facility, showing good alignment. The back-casting results would be void if a unit commitment algorithm were added at this stage of the process.
    - In real world operations, forecast errors result in unit commitment decisions that are imperfect. In consultation, Synergy suggested that forecast error should not be modelled in

the unit commitment algorithm due to this being impractical. EY does not consider the proposal to employ a perfect foresight model of unit commitment to be any more realistic than the modelling approach that was proposed in the Draft Assumptions Report.

- **Renewable projects**, there are no significant renewable generation projects that are likely to be on-line in the 2019-20 year that have not already been consulted on.
- **Fuel price assumptions**, the modelling applies the data provided by market participants directly.

1.5 Recommendations from the ERA's 2018/19 Determination

The ERA's determination of the ancillary service margin peak and margin off-peak parameters for the 2018-19 financial year (2018/19 Determination)[7] made a number of recommendations. The recommendations and the actions taken by AEMO and EY in response to them are outlined in Table 5 below.

Table 5: 2018/19 Determination recommendations and actions undertaken for the 2019/20 review.

Recommendation from 2018/19 Determination	Action undertaken in 2019/20 review
Paragraph reference 10. The ERA identified conceptual and mathematical improvements to the calculation of margin values. In particular, the ERA proposed revisions to the estimation of availability payments to better reflect the settlement outcomes of a competitive ancillary service market. The ERA revised the calculation of margin values to minimise forecast errors for Synergy's availability payments.	In developing the methodology for the 2019/20 review AEMO and EY discussed the conceptual and mathematical improvements outlined the 2018/19 Determination in consultation with the ERA's Secretariat. See Section 4.3 of this document.
Paragraph references: 11. A thorough review of the inputs to the model and a more intensive verification process with those parties providing assumptions, including an explanation of how the inputs will be used prior to modelling. 72. AEMO should publish its model validation and quality assurance processes to restore market participants' confidence in the process. 73. That AEMO thoroughly reviews the input assumptions with market participants and their subsequent use in modelling availability cost in the resource provision and counterfactual modelling scenarios. 44. That AEMO explicitly and confidentially tests fuel price input assumptions with market participants. In particular, that AEMO revisits the application of fuel supply curves in the market simulation model.	AEMO and EY undertook an extensive consultation on the input assumptions to the model. Specifically, AEMO: ► Published the WEM Modelling and Back Casting Report ► Published the Draft Public Assumptions Report, welcoming submissions ► Held a workshop with participants to provide an overview of the assumptions and model ► Reviewed and assessed two submissions, updating the approach accordingly ► Consulted with individual generators on their confidential assumptions (including fuel input assumptions), and ► Updated confidential assumptions to reflect all feedback received. ► EY prepared a detailed summary of the verification processes that would be undertaken. The summary described EY's quality assurance processes and procedures and explained how the quality assurance processes and procedures will ensure that the WEM simulation model is fit for purpose and does not produce significant modelling errors.

[7] Available here https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin_peak-and-margin_off-peak

Recommendation from 2018/19 Determination	Action undertaken in 2019/20 review
12. That AEMO annually conducts and publishes sensitivity and back-casting analyses as a routine part of estimating the margin values (refer to paragraph 47). 47. That AEMO continues to conduct and publish back-casting and sensitivity analysis annually to promote confidence in the estimation of margin values. These exercises could be used to improve model accuracy, validate model development, and facilitate the interpretation of modelling results. 72. AEMO should undertake and publish back-casting to restore market participants' confidence in the process.	EY undertook a back-cast and analysed outcomes for price and dispatch according to a number of different metrics, such as annual averages, duration curves and time-of-day averages. These metrics demonstrate the ability of the model to replicate history and the adequacy of the model for forecasting the market scenarios for the review and showed good alignment. Refer to the WEM Modelling and Back-cast Report for further information. As part of this review, EY will provide an analysis of the sensitivity of WEM simulation model outputs to changes in model inputs, identifying inputs and outputs that have a significant effect on the proposed margin values and the proposed SR_ Capacity Peak and SR_ Capacity_ Off-Peak values for the 2019-20 financial year.
Paragraph reference 46. To enhance transparency, that AEMO publishes a detailed explanation of the simulation model that has been developed, how input parameters are used, and how the model is validated.	The detailed explanation of the simulation model used by EY is included in the WEM Modelling and Back Casting Report.
Paragraph reference 67. That AEMO considers the principles outlined in paragraphs 56 to 59 to enhance the calculation of availability cost for the spinning reserve service in its future reviews of the margin values.	In developing the methodology for the 2019/20 review AEMO and EY discussed the conceptual and mathematical improvements outlined the 2018/19 Determination in consultation with the ERA's Secretariat. EY has modelled Synergy's availability cost as the opportunity cost of its provision of spinning reserve, rather than on the basis of a shadow price that may emerge from a theoretical spinning reserve market.

1.6 Report structure

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

- Section 2 presents an overview of modelling the WEM
- Section 3 provides a summary of the final market related assumptions used as inputs in the modelling
- Section 4 details the calculation of costs and the modelling methodology applied
- Section 5 details the results of the modelling simulations
- Section 6 discusses specific aspects of the modelling in greater detail
- Appendix A describes the plant parameters used with the market simulation model
- Appendix B specifies planned maintenance periods

2. Modelling the Wholesale Electricity Market

2.1 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.

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. 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),[8] presence of unserved energy (USE)[9] and generator availability amongst many other metrics.

2.2 Data and input assumptions

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 2 provides a high level overview in diagram form, including categorising the input assumptions in four categories.

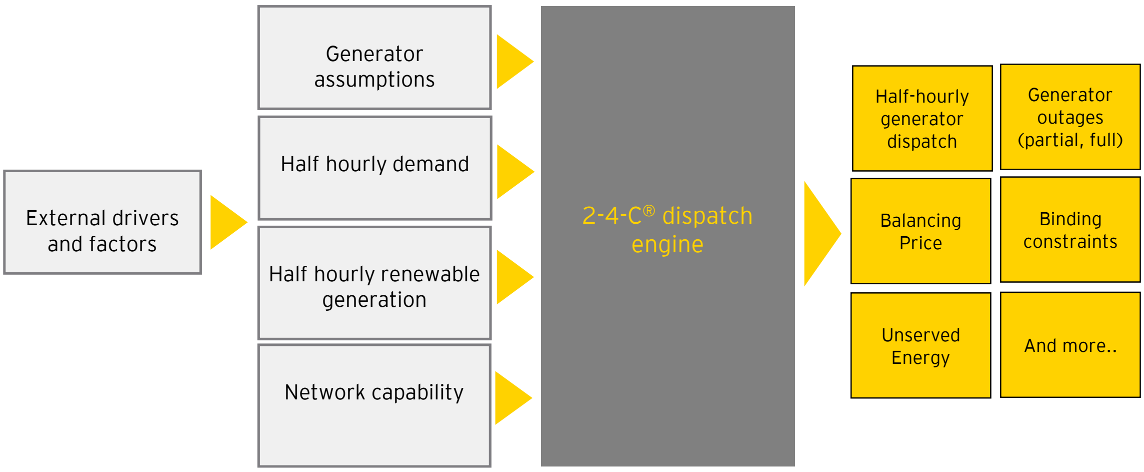

Figure 2: Simplified high level overview of the inputs and outputs to 2-4-C®

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

[9] 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.

The following points describe the four types of input assumptions in Figure 2:

- 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[10], 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 and more.[11]
- 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).[12] EY's half-hourly profile modelling tools combine these together to produce forecasts of the future half-hourly demand.
- Network capability defining 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.[13] However, the WEM currently operates without network constraint equations implemented in generation dispatch processes. Management of network constraints is currently facilitated by a number of post-contingent generation curtailment schemes and manual intervention by system operators if required.
- 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 production.[14]

Some of the input assumptions are processed in models external[15] to the 2-4-C® dispatch software to determine the quantities to be used.

[10] Determined in this review as a result of the back-casting exercise.
[11] Generator synchronisation times are not explicitly modelled. Implementation of synchronisation times will be considered in the formulation of the modelling methodology.
[12] AEMO Electricity Statement of Opportunities
[13] A network constraint equation is used by the dispatch engine to manage power flows across the transmission network by dispatching generation on or off for a particular constraint. The WEM does not automatically apply network constraint equations in dispatch, however, PUO reform packages are expected to be in place by 2022.
[14] Landfill/biomass generators are treated as thermal generators.
[15] An example of an external assumption not used directly in the dispatch modelling for the WEM is the Reserve Capacity Requirement. This may impact forward looking generator capacity requirements by setting the Capacity Credit requirement and the surplus used in calculating the Reserve Capacity Price. However, it is not explicitly used in dispatch modelling.

Figure 3 shows a detailed flow diagram detailing the interactions between 2-4-C®.

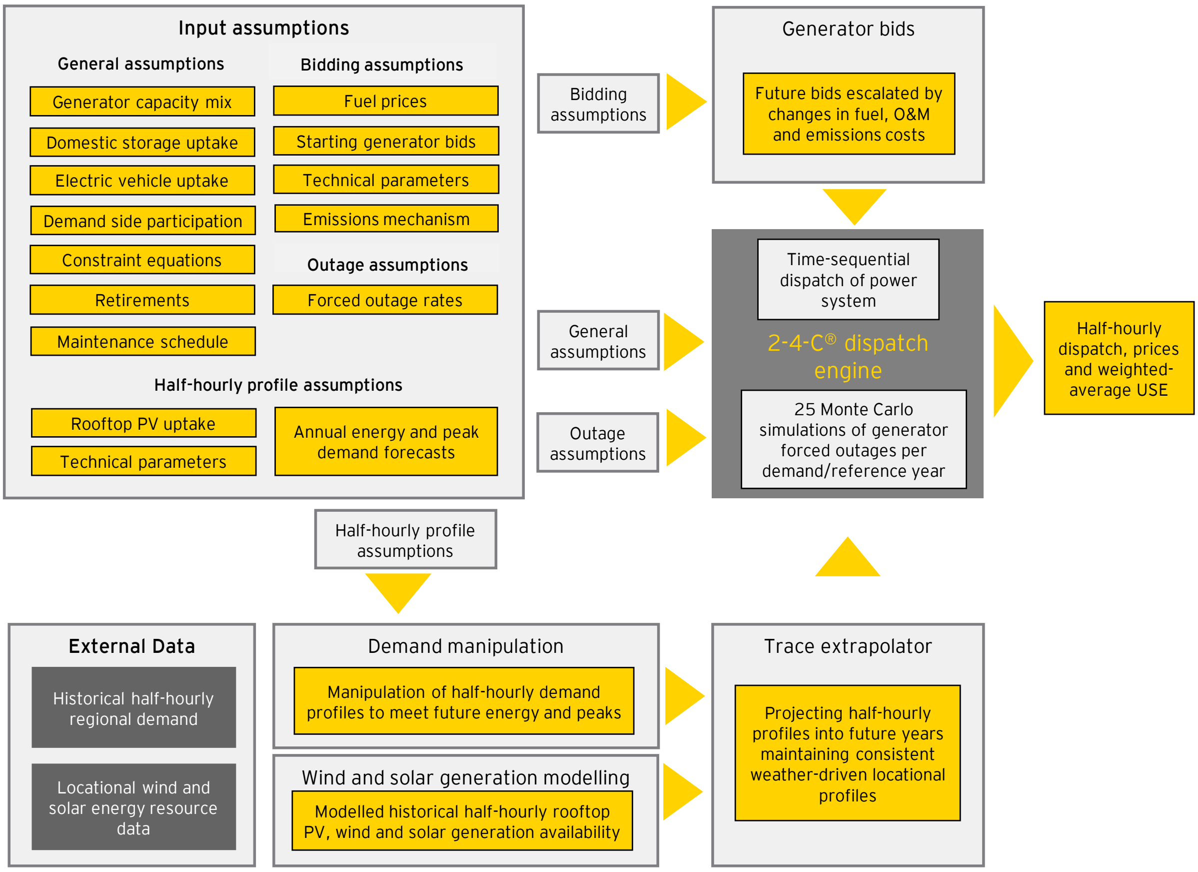

Figure 3: Data flow diagram for the market simulations

2.3 Simulation parameters

The potential for any particular 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 a single scenario, Monte Carlo simulations of generator outages, multiple reference years of historical data and consideration to 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.

Two reference years was proposed to be modelled. Margin value modelling has since simulated 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 6 provides a summary of key simulation parameters.

Table 6: 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	2016-17 was modelled as a reference year. 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.
Monte Carlo iterations	On the demand profile we will model 25 Monte Carlo iterations[16] 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 two reference years with a single demand profile with 25 Monte Carlo iterations of forced outage profiles (as described above).
Study period	The study period is from 1 July 2019 to 30 June 2020.

2.4 Back-casting of simulation results

As part of the review, EY performed a back-cast of its half-hourly modelling of the WEM. The objective of the back-cast was to devise suitable bidding profiles for each generator to emulate its dispatch patterns in an historical year to demonstrate the computational and mathematical accuracy of the model. Further information can be found in EY's 2018 WEM Modelling and Back-casting Report.

2.5 Overview of dispatch process

The dispatch of generation facilities is based on meeting operational demand in each trading interval, based on price quantity pairs offered into the market, subject to generator plant capability and availability, with the objective of minimising cost of generation supply.

Bidding profiles are devised to emulate dispatch priorities associated with providing energy and ancillary services. For the purpose of this review and calculating the theoretical cost of meeting spinning reserve, the model has been configured with short run-marginal cost (SRMC) bids, with the majority of available capacity offered in at SRMC to determine a theoretical least cost dispatch pattern. Specific departures exist for generator units providing ancillary services.

- Generators that provide LFAS are offer the minimum stable generation at the floor price to ensure they are effectively prioritised in dispatch. Any LFAS up or down service is priced at the respective price caps to ensure their capacity is available to the market. The IPP facilities that provide LFAS offer their LFAS quantity based on a historical offer profile.
- Contracted spinning reserve providers offer their capacity at the ceiling price effectively reserving a portion of their capacity for spinning reserve.
- All other coal units offer their minimum generation load at low prices to avoid unit cycling and for spinning reserve purposes.

[16] 25 iterations of Monte Carlo simulations produce converged dispatch outcomes suitable for the purposes of the modelling

3. Market related assumptions

The key market related assumptions applied in the modelling for the margin values 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, EVs, Industrial demand	AEMO 2018 WEM 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 and a submission from a market participant discussed in section 3.2.1.
Generation retirements	Synergy's announced 380 MW base retirement schedule, as specified in section 3.2.2
Fuel prices (gas and coal)	Contract fuel prices as provided by market participants, summarised in Appendix A.
Demand side management (DSM)	DSM capacity to be modelled as 66 MW from 2019-20 onwards for the duration of the study period.
Auxiliary factors	As provided by market participants, summarised in Appendix A.
Planned maintenance	A combination of typical maintenance schedules for technology types and specific planned maintenance for unit generators provided by market participants, detailed in Appendix B.
Spinning reserve contracts	Bluewaters is assumed to be contracted for 13 MW of spinning reserve across each unit (26 MW in total) with the contracted capacity withheld at the price cap. Interruptible load contracts are assumed to total 42 MW.

3.1 Demand modelling

Demand assumptions used in modelling include annual energy projections, peak demand, rooftop solar PV penetration, EV uptake and increased use of behind-the-meter battery storage.

The expected scenario from the AEMO WEM ESOO 2018 (expected growth scenario) has been adopted as the source of electricity demand and energy projection. An overview of the factors influencing operational demand for 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)	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

- Operational energy is the annual operational energy consumption to be met by large-scale generation facilities for the WEM on a sent-out basis.
- Peak demand is the peak demand value based on a 50% POE forecast. The 50% POE peak represents a typical year, with a one in two chance of the demand being exceeded in at least one half hour of the year and is representative of a statistically likely scenario.
- Installed rooftop PV capacity is provided in total MW. 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), significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs is expected.
- Behind-the-meter (domestic) storage profiles and EV charging profiles are modelled separately to capture their impact on the shape of grid demand without changes to the total underlying operational energy forecast in the WEM. 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.[17]

3.2 Generator assumptions

3.2.1 New entrant market generators

The following new entrant generators are included based on capacity credit certification and a market participant submission during the consultation period for the 2019-20 year. 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 revenue.

Revised commissioning dates for new entrant generators have been adopted, where provided by market participants.

Table 9: 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 Oct 2018
Northam Solar Project	10	East Country	SAT PV	27%	1 Oct 2018
Westgen Solar Farm	30	Kwinana	SAT PV	29%	1 Oct 2019
Merredin Solar Farm	120	East Country	SAT PV	28%	1 Jul 2019
Badgingarra Wind Farm	130	North Country	Wind turbine	44%	1 Jul 2019

3.2.2 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[18] is modelled as presented in Table 10. EY understands that Mungarra Power Station and West Kalgoorlie Power Station may be retained for

[17] AEMO WEM ESOO 2018
[18] Synergy 380 MW announcement

network support,[19] however these stations are not modelled for the purposes of dispatching energy and ancillary services.

Table 10: 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

3.2.3 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 Western Australian Gas Statement of Opportunities (WA GSOO).[20] 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.

A market participant submitted that AEMO's WA GSOO low gas price forecast should be adopted for the modelling exercise and that adoption of the expected gas price forecast over-estimates fuel cost inputs for gas generators, noting that spot market prices have been lower in recent years.

A submission was also received asserting that only pipeline commodity fees should be included in the formulation of generator offer curves and that reservation fees are a sunk cost. The submission also considers that it is important for AEMO to determine the proportion of generators that use spot transportation and apply a weighted average transport price for specific generators.

As a result of confidential submissions generator assumptions received during the consultation period, EY will be using gas generators' fuel costs provided by market participants for all existing gas generators rather than the AEMO's WA GSOO low gas price forecast. This overcomes the need to make assumptions on the abovementioned points raised in submissions. Furthermore, 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.

3.2.4 Coal prices

For this assessment, the coal price is assumed to remain constant at $2.60/GJ for the study period as per the 2018-19 Margin Value review.[21] Synergy have submitted variations to coal prices for Muja and Collie units, which have been adopted.

3.2.5 Forced outage rates

EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. The same outage statistics are applied for generators with the same fuel type. A 'mean time to repair' and a 'mean time to fail' value is assigned to each generator in the simulation. A unit on a forced outage is excluded from the Balancing Merit

[19] https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Arrangements-for-continued-power-supply-reliability-in-the-North-Country-and-Eastern-Goldfields-regions.pdf
[20] https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities
[21] 2018-19 Margin Value Review

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 a power station.

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

3.2.6 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)[22] in combination with typical maintenance schedules for technology types. Units on planned maintenance outages are excluded from the balancing merit order.

3.2.7 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 WEM. 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[23] for 2018-19. 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.[24] Appendix A summarises the MLF's used. New entrant generators are given an MLF of 1.000.

3.2.8 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. Appendix A summarises the auxiliary factors used.

3.2.9 Demand side management

DSM capacity to be modelled as per AEMO 2018 WEM ESOO, with 66 MW for the 2019-20 study period. DSM is offered to the market at the price cap.

[22] Scheduled outages are submitted to AEMO for use in their 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.

[23] 2018-19 loss factor report

[24] 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.

4. Calculation method

4.1 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 … [Peak/Off-Peak] 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 … [Peak/Off-Peak] 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 by 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.

4.2 Synergy's spinning reserve opportunity cost

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

$$\begin{gathered} A_t = \alpha_t \frac{1}{2} p_t (F_t - U_t + H_t - M_t - I_t), \\ A_t \geq 0,\ b \geq p_t \geq a, F_t \geq 0, \\ U_t \geq 0,\ H_t \geq 0,\ M_t \geq 0, I_t \geq 0, \end{gathered} \tag{3}$$

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 for the whole WEM in trading interval t
- ► U_t is the MW capacity necessary to cover the requirement for providing upwards LFAS for trading interval t
- ► H_t is the MW quantity of upwards LFAS capacity that does not contribute to meeting the spinning reserve requirement
- ► 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 (3) converts MW values into MWh values for each half hour trading interval.

To summarise Equation (3) 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.

4.3 Calculating the opportunity cost of providing spinning reserve

The ERA's 2018 Determination paper[25] (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 guided the interpretation and application 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 in Equation (4) below:

$$C_i(s_i) = \int_{J_i - s_i}^{Q_i} \big(p - f_i(x_i)\big)\, dx_i, \tag{4}$$

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, $\{x_i \geq 0\}$, J_i , $\{J_i \geq 0\}$, denotes the maximum rated capacity of the unit, and Q_i, $\{J_i \geq Q_i \geq 0\}$, is the level of output that the unit would sell into the balancing market if it were not providing spinning reserve. For the purposes of notational clarity the t subscripts have been suppressed in Equation (4).

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.

[25] 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

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 method for calculating the opportunity cost of a generation unit is described graphically in Figure 4 below, which is an adaptation of Figure A5 provided in Appendix 2 of the ERA's 2018 Determination.

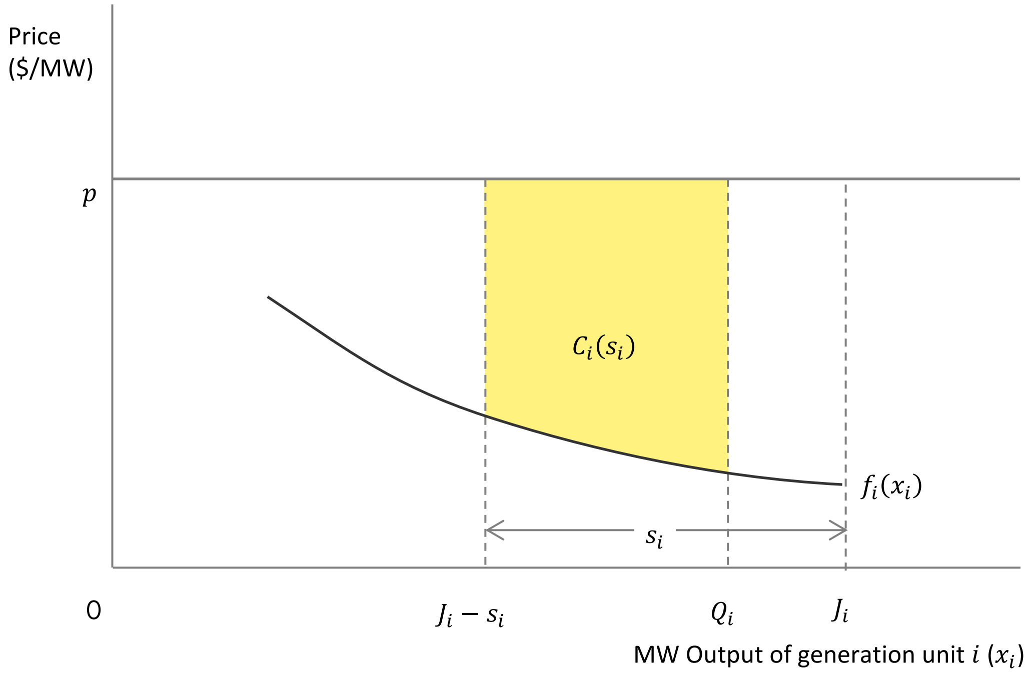

Figure 4: The opportunity cost of a generation unit's provision of spinning reserve

4.4 Modelling of availability cost

In light of Equation (3) 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 WEM on the basis of short run marginal cost balancing merit order profiles. Monte Carlo simulation 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 level of spinning reserve in each trading interval. EY's *Wholesale Electricity Market modelling and Backcasting Report* dated 31 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. This step also provides an estimate of the balancing price for each trading interval based upon the short run marginal cost bidding behaviour of market participants.

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 contributing to 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 4.5 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 generation units that are able to provide spinning reserve in each half hour trading interval of the modelling period, under the constraint that contracted (i.e. interruptible load and non-Synergy generation) spinning reserve is prioritised over Synergy spinning reserve. Optimisation is on the basis of generation units' marginal cost functions in each half hour trading interval. This method will be applied under an inequality constraint: the sum of all units' spinning reserve levels will be set to meet or exceed 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 4.6 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, now considering capacity allocated to spinning reserve to be bid at the market price ceiling.
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 4.6 below for more details on the spinning reserve cost optimisation method.
7. **Calculation of Synergy's availability cost.** Upon completion of step 6, the opportunity costs associated with non-Synergy spinning reserve plant and Synergy LFAS plant that concurrently provide spinning reserve will be removed from the minimised objective cost function to calculate Synergy's availability payment. See Section 4.7 below.
8. **Calculation of SR_Capacity_Peak and SR_Capacity_Off-Peak parameters.** The calculation of the average spinning reserve capacity for peak and off-peak trading intervals entails taking the arithmetic average of the dynamic spinning reserve requirement (step 3 above), plus the LFAS capacity not contributing to spinning reserve over peak and off-peak trading intervals. Details are provided in Section 4.8 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 4.9 below.

4.5 Dynamic spinning reserve requirement

Clause 3.10.2 of the Rules stipulates 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:

$$Y_t \geq \max[0.7G_t, 0.5\Delta D_t], \quad t = 1,2,3, \dots T, \tag{5}$$

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 expected change in operational demand between trading interval t and trading interval $t - 1$,[26]

then, the dynamic spinning reserve requirement net of LFAS capacity contributing to spinning reserve in trading interval t, S_t, is given by:

$$S_t = Y_t - U_t + H_t, \quad t = 1,2,3, \dots T. \tag{6}$$

4.6 Spinning reserve optimisation

EY's spinning reserve optimisation tool has been applied to answer two questions for each trading interval in the forecast period:

1. What level of output will each Synergy 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 by Synergy plant?

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

$$\begin{aligned} &\underset{m_i \leq x_i \leq Q_i}{\text{minimise}} && \sum_{i=1}^{N} C_i(s_i) \\ &\text{subject to} && \sum_{i=1}^{N} s_i \geq S - M \end{aligned} \tag{7}$$

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, and where the operator Σ indicates summation notation; t subscripts have been suppressed for clarity. An outage of any plant 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. Interruptible load contracts, denoted by M, were assumed to be 42 MW. M is assumed to be zero during the period of the planned outage schedule for the Simcoa load outlined in **Error! Reference source not found.** in REF _Ref531152681 \r \h Appendix B below.

After modelling commenced, EY found it necessary to include two additional inequality constraints to the optimisation problem given by (7) above, these being given by inequality equations (8), (9) and (10) below:

[26] The ΔD_t term is intended to reflect the requirement provided by clause 3.10.2(a)(i) of the 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.

$$s_i \leq \phi_i \tag{8}$$

$$\sum_{i=1}^{N} \min(\lambda_i, J_i - x_i) \geq 72 \tag{9}$$

$$\sum_{i=1}^{N} \min(\lambda_i, x_i - m_i) \geq 72, \tag{10}$$

where ϕ_i denotes assumed maximum spinning reserve capability of plant i and λ_i denotes the assumed maximum LFAS capability of plant i. These three inequality constraints ensure that units do not exceed their maximum spinning reserve capability and that the LFAS up and LFAS down requirements of 72 MW are met in all trading intervals.

AEMO advised that the Synergy high efficiency gas turbines and the NewGen Kwinana unit were assumed to be operating in all trading intervals of the year unless they were on outage. Of some interest is that in the short run marginal cost baseline the high efficiency gas turbines were not always on due to their relatively high position in the merit order. However, as they are relatively low cost to start and provide a high level of both LFAS and spinning reserve, the optimisation frequently turned these units on to provide LFAS and spinning reserve. This was on the basis of their place in the merit order for LFAS provision. An algorithm was employed to start Synergy's LFAS and spinning reserve capable plants up for trading intervals where there was insufficient LFAS or spinning reserve capacity, this being to avoid the LFAS and constraint equations from violating.

The optimisation concept is depicted in Figure 5 below, where the marginal opportunity cost or providing spinning reserve 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 spinning reserve 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.

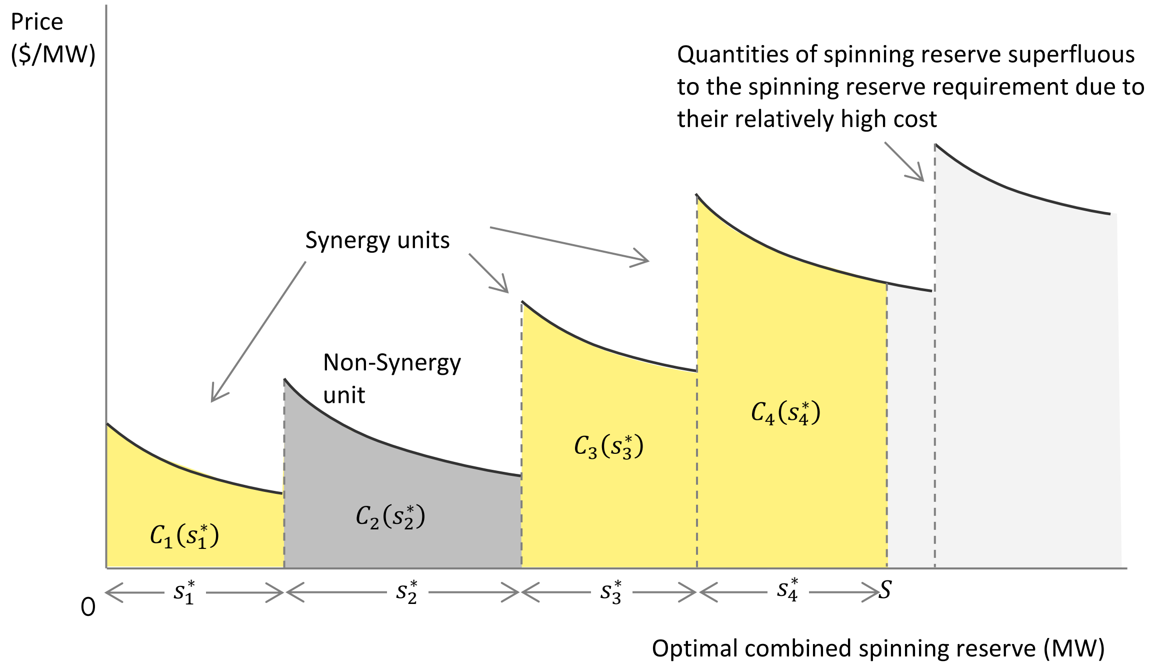

Figure 5: Graphical representation of the spinning reserve optimisation concept

4.7 Calculation of availability cost

Expression (7) 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 Expression (7), then Synergy's availability cost can be calculated as follows:

$$A = \sum_{i=1}^{N} C_i(s_i^*).w_i, \quad w_i = \begin{cases} 1 & \text{if unit } i \text{ is a Synergy plant} \\ 0 & \text{otherwise} \end{cases} \tag{11}$$

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 (11) for clarity.

4.8 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:

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

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 by letting $R_t = A_t$ it can be shown that:

$$K_t = F_t + H_t.^{27} \tag{13}$$

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 off-peak trading intervals for a year. As such, and in light of Equation (13), AEMO requires the SR_Capacity_Peak and SR_Capacity_Off-Peak parameter to be given by:

$$K_t = \begin{cases} \dfrac{\sum_{t \in P} F_t + H_t}{|P|}, & \forall\, t \in P \\ \dfrac{\sum_{t \in O} F_t + H_t}{|O|}, & \forall\, t \in O \end{cases}, \tag{14}$$

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 ∈, the cardinality of a set is denoted $|P|$ (i.e. $|P|$ denotes the number of peak trading intervals in a year), and the symbol ∀ denotes the universal quantifier (which means "for all").

4.9 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 6 below.

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

The U vector will be the upwards LFAS 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 Rules

Figure 6: 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, aimed at achieving $R_t \approx A_t$ over the 2019-20 financial year. EY will adopt a standard approach to regression analysis and reporting.

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. The functional form for the regression models that has been used in this modelling exercise is:

[27] To see this, substituting Equations (3) and (12) into $R_t = A_t$ and assuming $R_t > 0$ and $A_t > 0$, we have:

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

$$Q.E.D.$$

$$A_t = \hat{\alpha}\, Z_t + u_t, \qquad (15)$$

where u_t is a random error term with mean zero, $\hat{\alpha}$ is the coefficient to be estimated by minimising the sum of the squared residuals, weighted by a Hampel psi function (see Section 5.2 below),[28] from the regression, and where:

$$Z_t = \frac{1}{2} p_t . \max[0, K_t - U_t - M_t - I_t]. \qquad (16)$$

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

5. Results

5.1 Summary of results

Table 11 provides a summary of the results of the modelling and analysis using the methods and assumptions described in Sections 2 and 3 above. Results are expressed as a simple average across all Monte Carlo generator outage simulations for the key metrics. The Margin_Peak and Margin_Off-Peak values are derived through regression. The table also presents the margin values when calculated as an arithmetic average of the modelling outcomes for comparison.

Table 11: Summary of results

Reporting metric	Units	Modelled outcome	Std error
Weighted average balancing price, peak trading intervals	$/MWh	59.23	0.049
Weighted average balancing price, off-peak trading intervals	$/MWh	47.04	0.037
Arithmetic average balancing price, peak trading intervals	$/MWh	56.48	0.047
Arithmetic average balancing price, off-peak trading intervals	$/MWh	46.08	0.035
Average, annualised availability cost, peak trading intervals	$m	6.91	0.018
Average, annualised availability cost, off-peak trading intervals	$m	3.43	0.015
SR_Capacity_Peak	MW	235.4	0.063
SR_Capacity_Off-Peak	MW	236.4	0.072
Margin_Peak	%	17.32	0.030
Margin_Off-Peak	%	12.92	0.040
Arithmetic approach (for purposes of comparison only)			
Margin_Peak (arithmetic)	%	17.00	0.200
Margin_Off-Peak (arithmetic)	%	14.40	0.310

5.2 Margin values regression results

The ERA's 2018 Determination paper[29] (2018 Determination) suggested that applying a regression technique may be an improvement to previous methods of margin values estimation. EY explored a range of regression approaches, including:

- Ordinary least squares (OLS) regression
- Generalised least squares regression, which incorporated an autoregressive error structure to manage autocorrelation in the residuals

[29] 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

- An autoregressive integrated moving average algorithm combined with a regression model, again with a view to managing any autocorrelation in the residuals
- A robust linear regression model, applying a M-estimator and a Hampel psi function[30] to manage non-constant variance and non-normality of the residuals
- A Tobit model, noting that the explanatory variable (i.e. allocation costs) is from a censored probability distribution, which are known to impact the efficiency of regression parameter estimates.

In EY's opinion, the robust linear regression model appeared to provide the best fit to the data. Two robust linear regressions were conducted, one using all the peak trading interval data and the other using all the off-peak trading interval data from the Monte Carlo simulations. The summary results of the regressions from the R statistical package are provided in Box 1 and Box 2 below.

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

```
Call: rlm(formula = A.PEAK ~ 0 + Z.PEAK, psi = psi.hampel, method = "M")
Residuals:
    Min      1Q  Median      3Q     Max
-1943.9  -456.7  -380.0   163.0 16006.2

Coefficients:
       Value    Std. Error t value
Z.PEAK   0.1732   0.0003   566.1143

Residual standard error: 617.4 on 256199 degrees of freedom
```

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

```
Call: rlm(formula = A.OFFPEAK ~ 0 + Z.OFFPEAK, psi = psi.hampel, method = "
M")
Residuals:
     Min       1Q   Median       3Q      Max
-1426.13  -344.57  -311.57    48.33 12373.54

Coefficients:
          Value    Std. Error t value
Z.OFFPEAK   0.1292   0.0004   365.0164

Residual standard error: 495.3 on 182999 degrees of freedom
```

Robust linear regression is able to manage non-normality of the regression residuals, including the presence of outliers that would invalidate the OLS assumptions. The presence of outliers is evident in the Normal Q-Q plots of the residuals from the OLS regressions for peak and off-peak intervals across 25 sample simulations provided in Figure 7 below. If the data were following a normal distribution, the data points would closely follow the yellow lines in the plots. Both distributions appear to be highly asymmetric, which indicates that OLS would result in biased estimation of the margin peak and margin off-peak parameter values. The M-estimation approach provides a good balance between the efficiency of the regression results and the robustness of the analysis to outliers, and so is an appropriate method for the margin values calculation given the data generated from the market simulations.

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

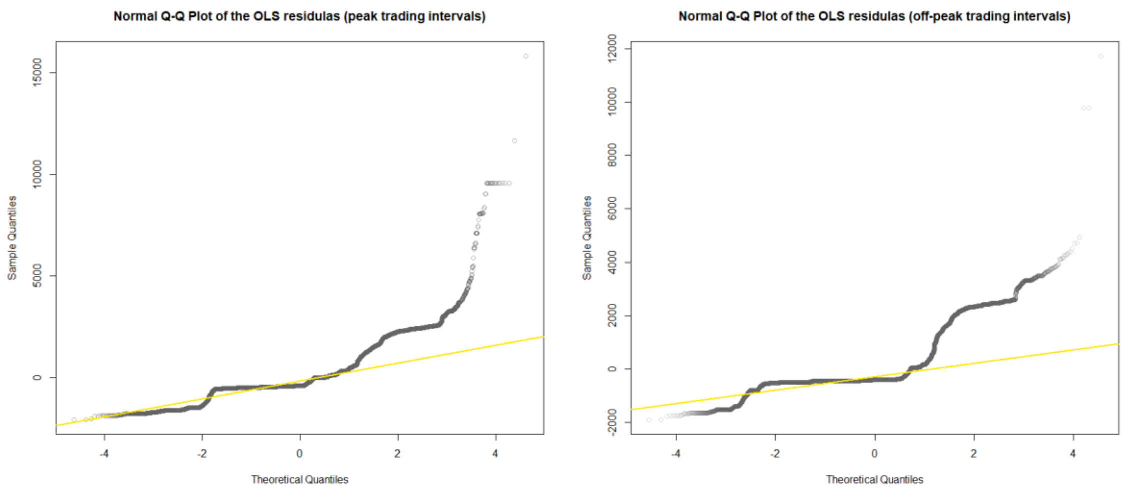

Figure 7: Normal Q-Q plots of the residuals form the two OLS regressions

Figure 8 below provides a scatter plot of the availability cost against the Z variable defined in Equation (16) above for both peak and off-peak trading intervals over sample data from 25 Monte Carlo simulations. The red lines in each panel of Figure 8 indicate the fitted regression through the origin, the slope of which is equal to the margin value parameter. The yellow lines indicate the arithmetic mean slope, derived by summing all of the availability cost data and then dividing this by the sum of all the Z variable data. It can be seen that the robust linear regression gives a slightly higher margin value estimate than that based on the arithmetic mean slope for peak trading intervals, and a slightly lower value for off-peak trading intervals.

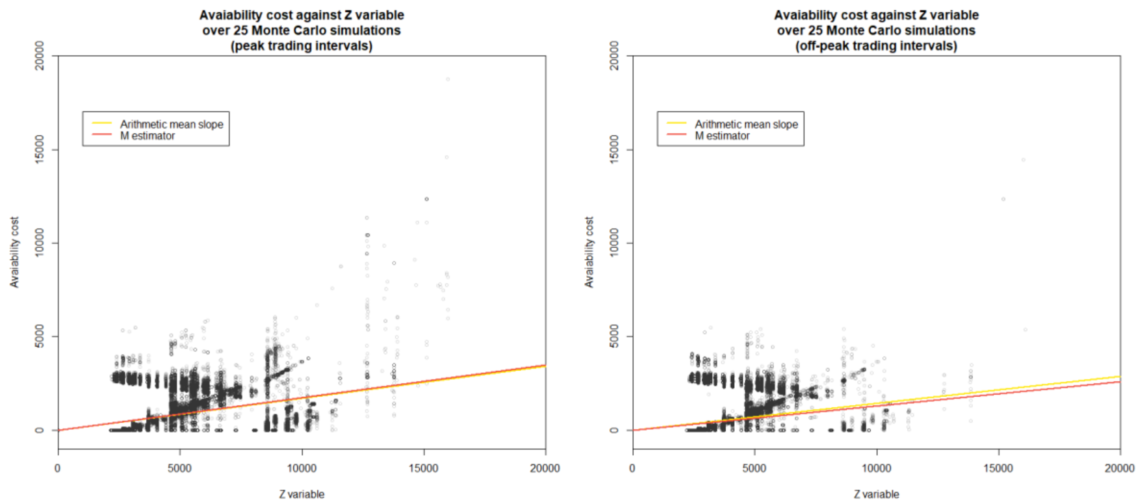

Figure 8: Scatterplots of the peak and off-peak regression variable, the M estimation fit and the slope based on an arithmetic mean

5.3 Availability costs

The availability cost was calculated using Equation (11) above for each half-hour trading interval in each Monte Carlo simulation. Synergy units that were modelled as providing LFAS up or LFAS down services in a trading interval, and that would not otherwise have cleared any of their output in the balancing market, were considered to incur zero allocation costs for the purpose of providing spinning reserve. This was to ensure that plants being compensated for provision of LFAS through the LFAS market were not also rewarded for coincidental provision of spinning reserve.

This filtering out of costs (or savings) associated with LFAS capable plants increasing their output, was conducted as a post model adjustment. This process removed a substantial amount of negative costs from the model outcomes. These negative costs were due to the objective function of the optimisation to be minimised being defined in a way that related the opportunity cost of spinning reserve to the difference between the balancing price, used as a proxy for a unit's marginal revenue, and the unit's marginal cost function (see Figure 4 above). Under this definition, an increase in output would result in a negative cost (i.e. a net revenue increase) whenever the balancing price is greater than a unit's marginal cost function.[31] This suggests that a potential improvement to the model might entail the explicit modelling of LFAS prices to define the opportunity cost for LFAS participants, rather than using the balancing price as a proxy for the unit's marginal revenue.

Table 12: Breakdown of total availability costs

Reporting metric	Unit	Peak	Off-peak	All intervals
Synergy average start-up costs to provide spinning reserve	$m	0.40	0.31	0.72
Synergy average profit foregone from withholding output for spinning reserve	$m	6.51	3.12	9.62
Availability cost (total)	**$m**	**6.91**	**3.43**	**10.34**

Note: table components may not sum to totals due to rounding

Start-up costs from the modelled market dispatch outcomes were calculated both before and after the spinning reserve optimisation was conducted in step 6. Net start-up costs due to spinning reserve were calculated as the difference between these two start-up cost calculations. Net start-up costs could be either negative or positive and were allocated evenly over all trading intervals during which the relevant unit was running after the optimisation was conducted. Negative net start-up costs occur when a unit that operates out of merit is able to avoid start-up costs that would otherwise have occurred if they were not providing spinning reserve, i.e. by filling in the gaps between trading intervals in which they are dispatched, thereby reducing cycling in and out of the balancing market.

For most units and Monte Carlo simulations, annual total net start-up costs were positive, indicating that in aggregate, additional start-up costs were incurred by plants that provided spinning reserve out of merit to the balancing market. However, in the case of the KWINANA_GT3 unit, annual total net start-up costs fell below zero in five of the Monte Carlo simulations, reaching an aggregate amount of −$22,500 for that generation unit in one of the simulations.

The process of evenly distributed negative net start-up costs over all the trading intervals during the year in which the units were generating reduced the allocation costs in those trading intervals by a small amount. Their subtraction from allocation costs resulted in there being four off-peak trading intervals (but no peak trading intervals) over the 25 Monte Carlo simulations in which allocation costs fell negative.

5.4 Spinning reserve requirement

The SR_Capacity_Peak and SR_Capacity_Off-peak values were calculated based on the requirements of the WEM Rules. In calculating the spinning reserve requirement, SWIS operational demand was examined to determine whether the maximum demand ramp expected over a period of 15 minutes had the potential to set the spinning reserve requirement in a significant amount of

[31] For example, if a unit would have cleared at 30 MW in the balancing market without optimisation, that unit's average costs decreases with output, and the optimisation results in the unit producing 60 MW to provide downwards LFAS, then because the optimisation uses the balancing price as a proxy for the unit's marginal revenue, the optimisation will result in an increase in the unit's profits. This increase in the unit's profits is calculated as a negative cost.

trading intervals. Figure 9 shows a scatter plot of the calculated ramp in operational demand across each half hourly period, multiplied by 0.5, assuming a consistent ramp rate.

The value of the demand ramp in a 15 minute period was calculated to exceed +/-200 MW in two 15 minute periods in the year. There were a total of 15 periods identified that exceeded a demand ramp of +/-150 MW. These values were compared against initial generation dispatch simulations, which indicated that the spinning reserve requirement in each trading interval was likely to be set by generation facilities rather than the ramping of operational demand.

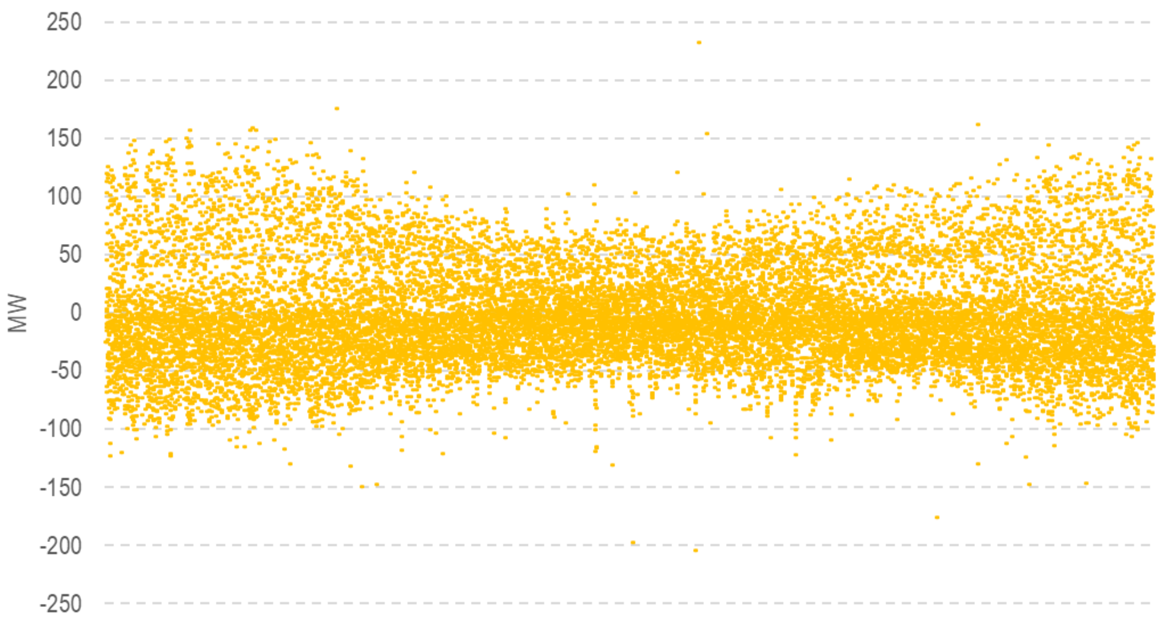

Figure 9: Calculated ramp in operational demand across a 15 minute period

The dispatch of generation resulted in NewGen Kwinana or Collie Power Station setting the largest spinning reserve requirement in about 92% of all trading intervals due to their installed capacity and their low cost of production. Figure 10 shows the duration of the year that these facilities were setting the spinning reserve requirement. Other generation facilities that set the spinning reserve requirement are mostly Bluewaters and Muja units.

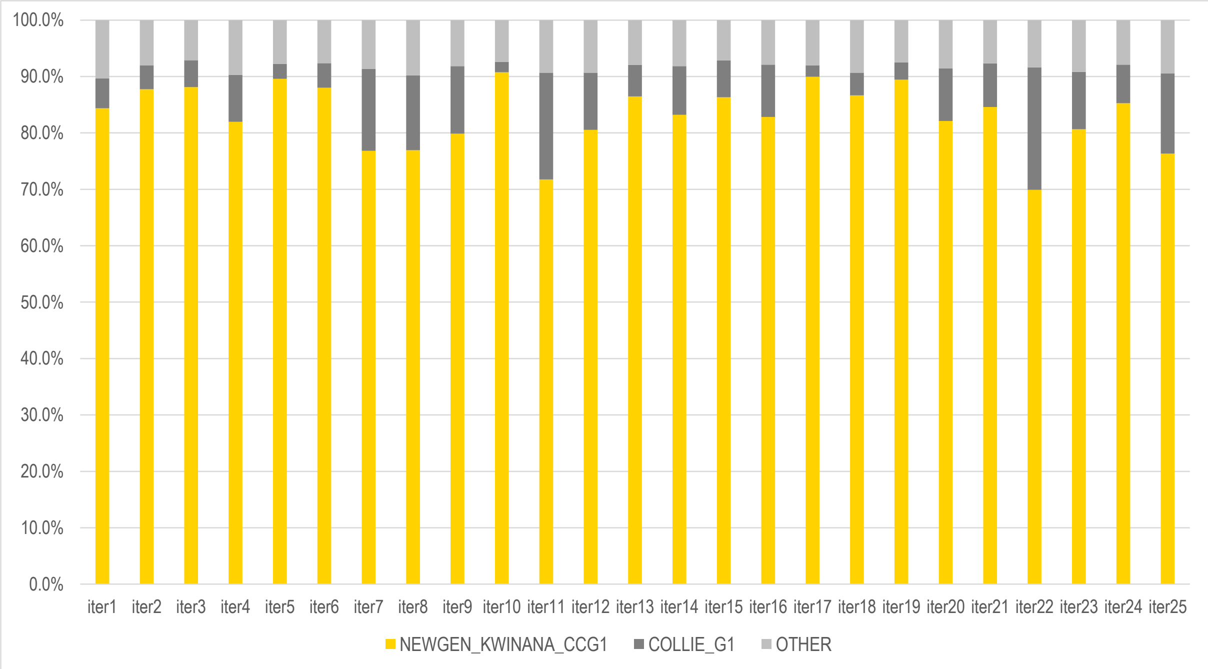

Figure 10: Duration of facilities setting the spinning reserve requirement

5.5 Load following ancillary services

In a pure SRMC bidding market most operational demand periods do not require gas turbine facilities on-line and Newgen Kwinana (NGK) is dispatched at its maximum output of 335 MW (subject to availability) due to its low cost of production. This results in trading intervals where there is frequently insufficient LFAS provisioned in the dispatch of generation required to meet operational demand and therefore a requirement for LFAS plants to be started up out of merit to provide LFAS services. The modelling steps start plants up to provide LFAS, before they are started up to provide spinning reserve.

The non-linear optimisation modelling most frequently chooses to turn on the Kwinana high efficiency gas turbine (HEGT) units for provision of LFAS_Up and LFAS_Down with NGK often turning down to 305 MW in order to provide 30 MW of both LFAS_Up and LFAS_Down. One of the Kwinana HEGTs is generally operated at min-load in order to provide maximum LFAS_Up and the other at a higher output in order to provide sufficient LFAS_Down.

5.6 Spinning reserve dispatch

Figure 11 shows a chart for the procurement of ancillary services for a single iteration of Monte Carlo outages. The spinning reserve provided by Synergy units is presented twice in the chart for clarity. It is presented as the yellow series in the stack chart which adds up to the prevailing spinning reserve requirement. It is also presented as the blue line on the secondary axis (noting it is the same scale) to more clearly show the quantity of spinning reserve provided by Synergy facilities in this sample.

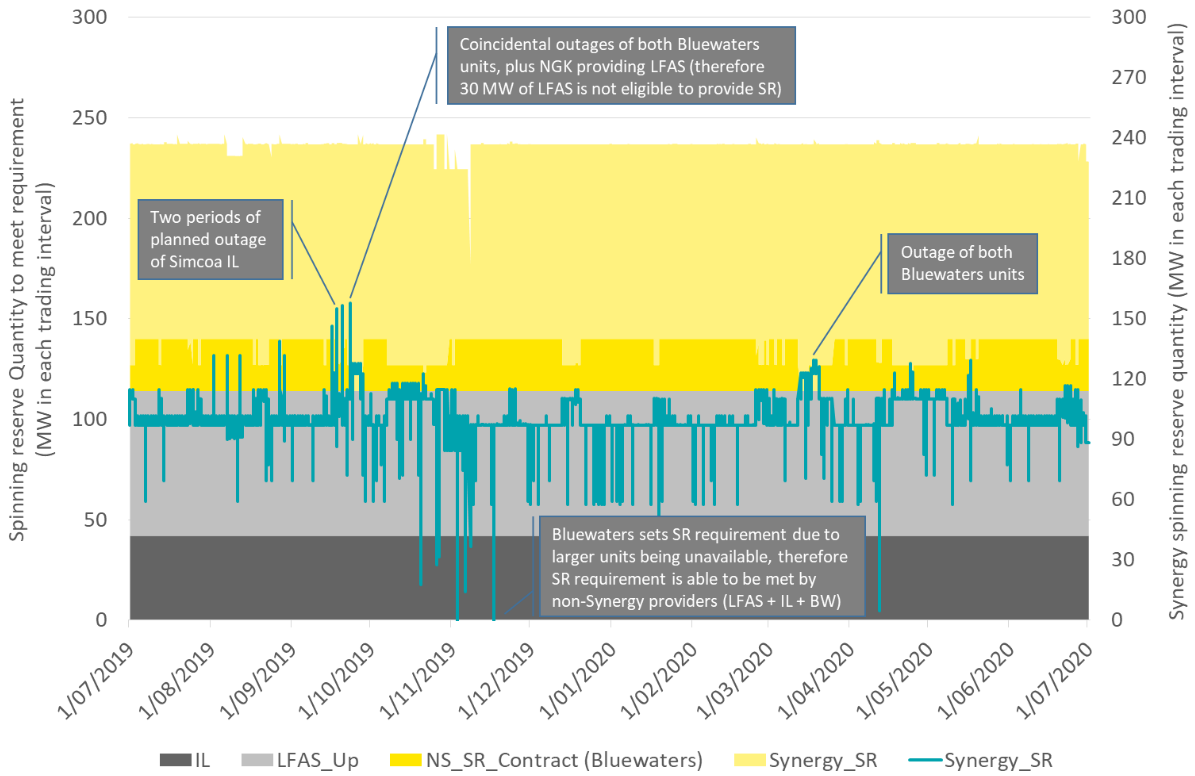

Figure 11: Stack chart for the provision of ancillary services for a single iteration

The interruptible load quantity of 42 MW is always assigned to spinning reserve first (subject to availability), thereby effectively reducing the spinning reserve requirement to be met by physical generation units. This is highlighted by the lower grey section in Figure 11. Procurement of LFAS up is then dispatched from the Kwinana HEGT and NGK[32] units most frequently.

The 26 MW of spinning reserve assumed to be contracted in this scenario from the Bluewaters facilities is always provisioned next when the facilities are available, prior to provisioning of spinning reserve from Synergy units. There are times where the available spinning reserve from the Bluewaters units is zero due to full or partial forced outage or planned outage combinations. These are the periods where Synergy facilities must provide the highest level of spinning reserve. There are a few periods of even higher provision of spinning reserve from Synergy facilities due to outage of other spinning reserve providers coincident with provision of LFAS_Up from NGK which does not contribute to spinning reserve (despite being dispatched for LFAS_Up).

The outcome of the initial conditions often sees NGK at its maximum output of 335 MW. Depending on the availability of LFAS and spinning reserve providers it is sometimes a least cost solution for NGK to be turned down to 305 MW as it may then provide LFAS_Up, as well as having the added benefit of reducing the spinning reserve requirement by 70% of the dispatch reduction (30 * 0.7 = 21 MW) due to the frequency at which it sets the spinning reserve requirement. It is noted that in the market this will be a function of LFAS market offers rather than least cost optimisation.

With the Kwinana HEGT's (and possibly NGK) providing LFAS, after subtracting interruptible load and Bluewaters spinning reserve, there usually remains a spinning reserve requirement shortfall. In a purely SRMC bidding world it is often the case that there is theoretically no need for Muja units to be on-line. However, turning off for short periods subsequently incurs start-up costs. Therefore, to avoid short periods of cycling a min-load offer has been established in the modelling for Muja

[32] It is noted that NGK is not assumed to be contracted to provide spinning reserve service in this scenario and therefore its 30 MW of LFAS does not count towards meeting the spinning reserve requirement. This is further explained below.

facilities. This is effectively avoiding the cost of re-starting the facilities shortly after shutting down. This is treated as a balancing market operating decision and therefore there is generally not a start-up cost incurred from Muja units in order to provide spinning reserve services.

The resulting provision of spinning reserve by Synergy facilities tends to be around 100 MW. It may be lower when the spinning reserve requirement is lower due to a smaller generation facility setting the requirement. It is often higher when contracted capacity from either interruptible load or non-Synergy generation facilities is not available or when NGK is providing 30 MW of the LFAS requirement.

The balancing revenue forgone is then calculated as the balancing price multiplied by Synergy spinning reserve provision, adjusted for whether the SRMC for such spinning reserve provision is above or below the prevailing balancing price and accounting for unit starts which are specific to the requirement for provision of spinning reserve.

5.7 Key Drivers

This is the first year in which EY's electricity market dispatch engine has been employed to calculate margin values. Moreover, in response to the recommendations made by the ERA in their 2018/19 Determination, this year's methodology has changed from those applied in previous years' reviews of margin values. As such, EY is unable comment on the impact of the change in methodology on the margin values calculation.

However, we make the following observations:

- All else being equal, an increase in Synergy's availability costs, on the left hand side of regression Equation (15), will result in larger margin values (and vice versa)
- All else being equal, an increase in the required provision of spinning reserve by Synergy, on the right hand side of regression Equation (15), will result in reduced margin values (and vice versa)
- However, not all else is equal - EY's methodology, developed in the context of the ERA's recommendations, calculates the availability cost with reference to the balancing price. However, the right hand side of regression Equation (15) is also a function of the balancing price. A change in the balancing price will affect both sides of the regression equation in the same direction. This implies that the margin value calculation may be reasonably robust to changes in the balancing price.
- This year's SR_Capacity_Off-Peak value is higher than in previous reviews and is similar to the SR_Capacity_Peak value. EY's modelling finds that NewGen Kwinana operates in most trading intervals of the year, either in the balancing market or in the LFAS markets, and sets the spinning reserve requirement in most trading intervals. An increase in the SR_Capacity_Off-Peak increases the required provision of spinning reserve by Synergy for off-peak trading intervals, relative to availability costs. This will result in lower margin values for off-peak trading intervals than would otherwise be the case.
- EY's estimation of the 2019-20 availability cost is 39% lower than that calculated for the 2018-19 year. If all other variables in the margin value calculation were held constant, a reduction in availability cost of 39% would see a reduction in margin values of approximately 39%.

Appendix A Facility related assumptions

At the request of AEMO, EY prepared pre-populated excel spreadsheets containing assumptions for each market participant's facility. AEMO requested market participants to review and update commentary on facility related assumptions. AEMO received responses from 13 out of 15 participants. The type of assumptions requested and used in modelling are shown in the template Data and assumptions workbook.[33]

In the event that the assumptions were not updated or a response was not provided, EY has retained the default assumptions for the purposes of modelling.

Where data has been submitted that is inconsistent with existing standing data, EY has adopted the values provided via submissions.

[33] http://wa.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/Ancillary-Services/2018/PUBLIC---EY-Assumptions-Book---AEMO-Margin-Value-Review---2018-09-13c.pdf

Appendix B 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.

[34] Scheduled outages are submitted to AEMO for use in their 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.

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