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2020-21 Energy Price Limits Review – Draft Report (Public)

A report for the Australian Energy Market Operator

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About Us

Established in 1996, Marsden Jacob Associates has grown to be Australia's leading dedicated natural resource economics, policy and strategy advisory. We employ talented economists and policy advisors who specialise in solving practical, real world problems relating to water, energy, environment, natural resources, agriculture, earth resources, public policy and transport. We work with a wide range of cross-disciplinary partner firms to deliver best project outcomes for our clients.

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Acronyms and abbreviations

AEMO	Australian Energy Market Operator
ACPL	Australian Cents Per Litre
BM	Balancing Market
CCGT	combined cycle gas turbine
DBNGP	Dampier to Bunbury Natural Gas Pipeline
ERA	Economic Regulation Authority
FOM	fixed operating and maintenance
GGP	Goldfields Gas Pipeline
GJ	gigajoule
GST	Goods and Services Tax
GW	gigawatt
GWh	gigawatt hour
kW	kilowatt
kWh	kilowatt hour
LRET	Large-scale Renewable Energy Target
MLF	marginal loss factor
MW	megawatt
MWh	megawatt hour
NCS	Network Control Service
NPV	net present value
O&M	operating and maintenance
OCGT	open cycle gas turbine
PJ	petajoule
ppm	parts per million
PV	photovoltaic
RET	Renewable Energy Target
SRMC	short run marginal cost
STEM	Short Term Energy Market
TGP	Terminal Gate Price

Definitions

Term	Explanation
Balancing Market	Accounts for imbalances between a market participant's net contract position (after STEM nominations) on the scheduling day (day before trading) and their actual position on the trading day. Trading in the Balancing Market can result from incorrect demand forecasts and/or plant outages, or deliberate trading strategies by retailers to take some balancing market exposure (can lower purchase costs in particular circumstances).
Capacity Factor	The ratio of the average output of a generator (in MW) for a given period to the rated capacity of that generator. The formula for capacity factor is Total Output (in MWh) / Period (in Hours) / Rated Capacity (in MW). A ratio of 0.5 implies that the generation plant is running at 50 per cent of its rated capacity for that period.
Dispatch Cycle	The process of starting a generating plant, synchronising it to the electricity system, ramping it up to minimum generation as quickly as possible, changing its generation between minimum and maximum levels to meet system demand requirements, ramping it down to minimum generation and then to zero for shut-down.
Dispatch Cycle Cost	Total costs incurred in the start-up and shut-down (Dispatch Cycle) of a peaking gas turbine divided by the amount of electrical energy (in MWh) generated during a Dispatch Cycle.
Energy Price Limits (or Price Caps)	The Maximum STEM Price (applies to non-liquid fuelled facilities), the Alternative Maximum STEM Price (applies to liquid fuelled facilities), and the Minimum STEM Price expressed in $/MWh[1]. The Maximum and Alternative Maximum STEM Prices are reviewed annually by AEMO and approved by the Economic Regulation Authority[2]. The Minimum STEM Price is -$1000/MWh[3].
Fixed O&M	Fixed operating and maintenance costs that do not change with variations in generation output. Can include some labour costs, overheads and time related maintenance costs. Usually expressed in $/MW/annum.
Heat Rate	A measure of the efficiency of a generation plant that converts fuel into electricity. Usually measured in GJ/MWh and is a function of the utilisation of the generation plant (i.e. lower heat rate at higher plant utilisation).
Loss Factor (or Marginal Loss Factor)	Transmission loss factors that are used to determine how much sent out electricity is delivered to the regional reference node (Muja)[4]. A Loss factor less than unity implies that less energy is delivered to the node than what is injected into the transmission network and vice versa if the Loss Factor is greater than unity.
Margin	The difference between the maximum Energy Price Limits and the expected value of the highest short run costs of a peaking generation plant.
Mungarra Units	Collectively means the 3 gas turbine units at the Mungarra Power Station registered in the WEM as individual facilities MUNGARRA_GT1 and MUNGARRA_GT3.
O&M	Operating and maintenance costs. These are the non-fuel expenses incurred in running a generation plant (e.g. water, lubricants, labour and equipment).

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[1] Chapter 11 of the WEM Rules
[2] Section 6.20 of the WEM Rules
[3] Chapter 11 of the WEM Rules
[4] Chapter 11 of the WEM Rules

Parkeston Units	Collectively means the PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG.
Pinjar Units	Collectively means the 6 Pinjar 40MW gas turbine units registered in the WEM as individual facilities PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5 and PINJAR_GT7.
Risk Margin	A measure of uncertainty in the assessment of the mean short run marginal cost for a generation plant, expressed as a fraction.[5]
Short Run Marginal Cost	The additional cost of producing one more unit of output from an existing generation plant. In the context of this report it refers to the increase in the total production cost arising from the production of one extra unit of electricity and is measured in $/MWh.
Short Term Energy Market (STEM)	A day ahead forward market that is operated by AEMO to allow wholesale market participants to buy and sell electricity to adjust their net bilateral contractual positions for the next trading day.
Variable O&M	Variable operating and maintenance costs that change with variations in generation output. Includes but is not limited to start-up related costs. Usually expressed in $/MWh of generation (generated or sent out).
WEM Rules	The Western Australian Wholesale Electricity Market Rules.

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[5] Clause 6.20.7(b) of the WEM Rules

Executive Summary

Marsden Jacob Associates (Marsden Jacob) was appointed and undertook the modelling for calculating revised values for the Maximum STEM Price and Alternative Maximum STEM Price (referred to as Energy Price Limits) to apply in the Wholesale Electricity Market (WEM) for the 2020-21 year. Marsden Jacob undertook this work for the 2019-20 review.

This annual review is required under clause 6.20.6 of the Wholesale Electricity Market Rules (WEM Rules).

Required Methodology

In accordance with clause 6.20.7 of the WEM Rules, the Maximum STEM Price and Alternative Maximum STEM Price must be set based on the estimate of the short run marginal cost of the highest cost generating facility in the South West Interconnected System (SWIS) fuelled by natural gas and distillate respectively.

For the selected generator, the determination of this generator's short run marginal cost requires:

- The following factors to be determined for that generator: Variable Operating and Maintenance costs ($/MWh), Heat Rate (GJ/MWh), Fuel Cost ($/GJ), Loss Factor at its connection location, and a Risk Margin (that is expressed as a fraction and represents the level of uncertainty);

- The factors are expressed as distributions as forecasts of these factors are uncertain;

- The Maximum STEM Price and Alternative Maximum STEM Price must be calculated using the following equation defined in clause 6.20.7(b) of the WEM Rules:

$$\frac{1 + Risk\ Margin}{Loss\ Factor} \times \left(Variable\ O\&M_{\$/MWh} + \left(Heat\ Rate_{GJ/MWh} \times Fuel\ Cost_{\$/MWh} \right) \right)$$

- The variable cost is to be calculated over combinations of the factor distributions, and selecting the value based on a defined percentile of the variable cost distribution;

- The Maximum STEM Price and Alternative Maximum STEM are treated differently in relation of Fuel Costs:

    - gas costs are developed as a distribution based on the outlook and uncertainty; while

    - as the Alternative Maximum STEM Price is updated monthly and is split into two components: a constant non-fuel component ($/MWh) and a fuel component (GJ/MWh).

Modelling Steps

The approach undertaken by Marsden Jacob was the same as was used for the 2019-20 review. This involved the following:

- Selecting the generator(s) to be the basis of the upper Energy Price Limits. Two generators were selected;

- Obtaining data on the factors noted above;

- Quantifying the amount of uncertainty in factors;

- Using natural gas costs for the Maximum STEM Price and distillate costs for the Alternative Maximum STEM Price;

- Undertaking simulations to develop the distributions of the selected generator variable costs based on the uncertainty in the relevant factors;

- From this, developing the Maximum STEM Price and Alternative Maximum STEM Price for the two selected generators as the 80th percentile of the variable cost distribution (the selection of the 80th percentile accounts for the Risk Margin factor);

- The generator that resulted in the highest Maximum STEM Price and Alternative Maximum STEM Price set these values;

- Comparing the calculated upper Energy Price Limits for 2020-21 to that calculated in the previous 2019-20 review.

Selection of the Highest Cost Generator(s)

The WEM Rules stipulate that the candidate units for setting of the Maximum STEM Price and Alternative Maximum STEM Price must be 40 MW open cycle gas turbine units[6]. Based on this requirement, Marsden Jacob analysis and the previous 2019-20 review, the generator units selected were:

- Pinjar Units: the 6 Pinjar 40 MW gas turbine units registered in the WEM as individual facilities PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5 and PINJAR_GT7 (these are located on the outskirts of Perth); and

- Parkeston Units: the PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG (these are located in the Goldfields Region).

These were the same generator units used in the 2019-20 review.

The Mungarra Units (the 2 gas turbine units at the Mungarra Power Station) were considered, but these units will not be dispatched in the WEM except under the terms of the Network Control Services arrangement. This made them not suitable for selection.

Determination of the Factor Distributions

Marsden Jacob was provided with data through AEMO by contacting the generator operators to aid in the development of the factors for distribution. The assessment of the factors was as follows:

- Variable O&M (those costs that vary with electricity generation) depend on variable operating labour costs, usage-related maintenance costs (i.e. labour and materials) and non-fuel inputs such as lubricants and water. A key determinant is the number and costs of generator unit starts and how this impacts maintenance costs. From the distribution of the number of events where Balancing Prices continually exceeded $100/MWh, distributions of Variable O&M for the selected generators was developed.

- Heat Rate varies with generator output. The modelling had start-up heat energy between 9 to 15 GJ/start for each turbine. Start-up energy consumption was aggregated across all generation for that start.

- The Loss Factors were based on the 2019-20 year. These were Pinjar 1.0369 and Parkeston 1.1633.

- Gas prices required both gas commodity costs and gas transport costs to be determined. Gas data included the gasTrading data in the development of average and gas price uncertainty, where the average of the past year was considered the best estimate of the expected value for the coming year. Marsden Jacob used the "best" ARIMA model to generate estimates of gas price volatility.

- Distillate prices reflected movements in crude oil prices.

Statistical Monte Carlo Modelling

With the distributions determined, Monte Carlo simulation were performed. This involved sampling at random from input probability distributions of the Variable O&M, Fuel Cost and Heat Rate.

Each set of samples, called an iteration, provided an outcome of the variable cost, and was recorded.

Marsden Jacob undertook 10,000 iterations of the model to generate the probability distribution of possible Maximum STEM Price outcomes. The Risk Margin was determined as the difference between the mean and the 80th percentile.

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[6] Clause 6.20.7(b)(i)-(v) of the WEM Rules

Modelling Results: 2020-21

Table ES1 presents the calculated Maximum STEM Price and Alternative Maximum STEM Price for the Pinjar and Parkeston Units.

Table ES1: Calculated Maximum STEM Price and Alternative Maximum STEM Price 2020-21

	Pinjar Units	Parkeston Units
Maximum STEM Price	244.36	128.03
Alternative Maximum STEM Price	576.75	371.03

Source: Marsden Jacob analysis 2020

The upper Energy Price Limits for 2020-21 have been calculated as follows:

▪ Maximum STEM Price of $244.36/MWh; and

▪ Alternative Maximum STEM Price of $576.75/MWh.

As observed from Table ES1, the Pinjar Units had both the highest Maximum STEM Price and Alternative Maximum STEM Price. This meant that the Pinjar Units were used to set the upper Energy Price Limits.

Table ES2 and Table ES3 presents the component values determined from the modelling that make-up the Maximum STEM Price and Alternative Maximum STEM Price for the Pinjar Units.

Table ES2: Calculation of Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.19
Mean Fuel Cost (heat rate adjusted)	$/MWh	108.78
Loss Factor		1.0369
Before Risk Margin	$/MWh	211.45
Risk Margin Added	$/MWh	32.90
Risk Margin Value	%	15.56
Assessed Maximum STEM Price	$/MWh	244.36

Source: Marsden Jacob analysis 2020

Table ES3: Calculation of the Alternative Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.07
Mean Fuel Cost (heat rate adjusted)	$/MWh	432.43
Loss Factor		1.0369
Before Risk Margin	$/MWh	523.59
Risk Margin Added	$/MWh	53.16
Risk Margin Value	%	10.15
Assessed Alternative Maximum STEM Price	$/MWh	576.75

Source: Marsden Jacob analysis 2020

Change in upper Energy Price Limits from 2019-20 Review

Figure ES1 and Figure ES2 presents for the Pinjar units:

- The calculated Maximum STEM Price and Alternative Maximum STEM Price for 2019-20;
- The increase in the cost components from 2019-20 to 2020-21;
- The calculated Maximum STEM Price and Alternative Maximum STEM Price for 2021-21.

Figure ES1: Change in the Maximum STEM Price from 2019-20

	2019-20	Fuel Cost	VOM Cost	Loss Factor	Risk Margin	2020-21
Maximum STEM Price	234.57	-4.24	+5.50	-0.04	+8.57	244.36

Figure ES2: Change in the Alternative Maximum STEM Price from 2019-20

	2019-20	Fuel Cost	VOM Cost	Loss Factor	Risk Margin	2020-21
Alternative Maximum STEM Price	567.42	-4.68	+5.50	-0.02	+8.53	576.75

Figure ES 1 and Figure ES2 shows that the Risk Margin has the highest impact followed by the Variable O&M costs, Loss Factor and then the Fuel Cost. (The reasons for changes in the Maximum STEM Price since last year are explained in detail in Chapter 10.)

In relation to the changes to the assessed Energy Price Limits based on the Pinjar Units, the following are noted:

- The Risk Margin reflects higher volatility in the distribution obtained (this is described in the points below).

- Confidential data on the expected Variable O&M costs per year showed higher mean cost per start (increases Variable O&M) and more variability in cost per start (increases Risk Margin).

- The dispatch of Pinjar Units for 2019 showed an increase capacity factor to 2% from less than 1% in the previous year. The impact of this change is lower mean heat rates (reduces Fuel Costs), higher dispatch per start (reduces Variable O&M) and a wider range of operating capacities (increases Risk Margin).

- The Fuel Costs are lower which acts to lower the upper Energy Price Limits.

1. Background and Scope of Work

1.1 Purpose of this report

AEMO is responsible for operating the Wholesale Electricity Market (WEM) in Western Australia and is required to undertake certain reviews in accordance with the WEM Rules.

Section 6.20 of the WEM Rules provides information with respect to the Energy Price Limits, which represent the upper and lower price limits for offers submitted into the Short Term Energy Market (STEM) and the Balancing Market. The three price limits are[7]:

- Maximum STEM Price (which applies if a Facility is running on non-liquid fuel);

- Alternative Maximum STEM Price (which applies if a Facility is running on liquid fuel); and

- Minimum STEM Price (which is set at negative $1000/MWh under the WEM Rules).

Under clause 6.20.6 of the WEM Rules, AEMO must annually review the appropriateness of the value of the Maximum STEM Price and the Alternative Maximum STEM Price. Those revised values must then be submitted to the Economic Regulation Authority (ERA) for approval[8].

Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the upper Energy Price Limits for the 2020-21 year.

1.2 Scope of Work

Marsden Jacob is required to calculate revised values for the upper Energy Price Limits, as prescribed in clause 6.20.7 of the WEM Rules. This requires us to undertake the following tasks:

a) assess the methodology used in the previous 2019-20 Energy Price Limits Review and clearly articulate and justify any changes that Marsden Jacob recommends to the methodology (ensuring that the methodology is consistent with the requirements in clause 6.20.7 of the WEM Rules), including consideration of:

    a. the ERA's recommendations captured in its previous Energy Price Limits determinations, specifically:

        i. potential inclusion of the Mungarra units in this year's review (section 5.2 of the 2017 Energy Price Limits Decision);

        ii. fully capturing the variability of future maintenance expenditures in estimating the distribution of Variable O&M costs, such as:

            1. using a weighted average cost of capital (instead of a risk-free rate) to derive a distribution for the present value of maintenance expenditures and subsequent annuity amounts; and

            2. using the entire present value distribution to derive the Variable O&M cost and average variable cost distributions, rather than a single sample (i.e. the 80th percentile) of the present value of future maintenance expenditures;

        iii. obtaining information from asset owners about the actual maintenance status of the facilities and their expected retirement time;

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[7] Refer to Price Caps in Chapter 11 of the WEM Rules
[8] Clause 6.20.10 of the WEM Rules

iv. estimation of the risk margin, in particular the use of an 80th percentile, rather than an average of the distribution could lead to overly conservative energy price caps; and

v. review the application of Monte Carlo analysis to ensure that samples drawn from underlying distributions (for heat rate, gas price, and Variable O&M) are drawn and combined randomly to produce the average variable cost distribution;

b) provide independent modelling, analysis and justification for the cost assumptions and input data prescribed in clause 6.20.7 of the WEM Rules and used for determining the proposed price limits, including a specific focus on the determination of, and impact on, proposed price limits of:

 a. gas price distributions; and

 b. any other relevant issues that arise during the review; and

c) propose any revised price limits to be applied for the 2019-20 financial year.

1.3 Note to the Scope of Work

Marsden Jacob undertook this review for the 2019-20 year. The learning and model developments that were associated with that review were brought to this assignment.

1.4 Structure of the report

The structure of the proposal is outlined below:

- Chapter 1: Background and Scope of Work;

- Chapter 2: Methodology Review;

- Chapter 3: Selection of the Candidate Peaking Generator;

- Chapter 4: Variable O&M Costs;

- Chapter 5: Heat Rates;

- Chapter 6: Loss Factors;

- Chapter 7: Gas and Distillate Costs;

- Chapter 8: Statistical Modelling and Risk Margin;

- Chapter 9: Modelling Results;

- Chapter 10: Changes in Energy Price Limits Compared to Previous Years.

2. Methodology Review

This chapter discusses the methodology as it was applied in this review. Previous reports and stakeholder feedback on the upper Energy Price Limits have been incorporated into the methodology for period 2020-21.

The chapter presents:

- An overview of the methodology; and

- A description of the factors to be determined.

2.1 Overview of Approach to the Calculation of Maximum Prices

Basis of Calculation

Maximum prices serve several purposes in the WEM:

- Protect market customers from high prices that could result from generators exercising market power in the STEM and Balancing Market;

- Provide incentives for new generation investment (i.e. peaking generators);

- Enable existing generators to cover the costs incurred in providing peaking generation so that they are encouraged to provide their capacity during high price periods.

Market efficiency is maximised if wholesale market prices (including maximum prices) reflect the efficient costs of supply. The purpose of this analysis is to determine the efficient costs consistent with the role of the upper Energy Price Limits in the WEM.

In accordance with clause 6.20.7 of the WEM Rules, the Maximum STEM Price and Alternative Maximum STEM Price must be set based on the estimate of the short run marginal cost of the highest cost generating facility in the South West Interconnected System (SWIS) fuelled by natural gas and distillate respectively.

The Maximum STEM Price and Alternative Maximum STEM Price must be calculated using the following equation defined in clause 6.20.7(b) of the WEM Rules:

Equation 1

$$\frac{1 + Risk\ Margin}{Loss\ Factor} \times \left(Variable\ O\&M_{\$/MWh} + \left(Heat\ Rate_{GJ/MWh} \times Fuel\ Cost_{\$/MWh} \right) \right)$$

where:

- R*isk* M*argin* is a measure of uncertainty in the assessment of the mean short-run average cost of a 40 MW open cycle gas turbine generating station, expressed as a fraction;

- V*ariable* O&M is the mean variable operating and maintenance cost of a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up costs;

- H*eat* R*ate* is the mean heat rate at minimum capacity of a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

- F*uel* C*ost* is the mean unit fixed and variable fuel cost of a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and

- L*oss* F*actor* is the marginal loss factor of a 40 MW open cycle gas turbine generating station relative to the reference node.

There is some uncertainty regarding all the variables that make up the formula for the upper Energy Price Limits, except for the Loss Factor that is published by the Network Operator (Western Power). This implies that probability distributions can be found for the following key variables: Heat Rate, Variable O&M, and Fuel Cost.

Using Monte Carlo analysis, Marsden Jacob can generate distributions of likely maximum prices in the STEM/Balancing Market and then choose a percentile level (typically 80th percentile) to derive the maximum price limit.

Current price limits are set by reference to the following:

- Maximum STEM Price is chosen as the 80th percentile of the output price distribution;
- The Risk Margin is an output of this assessment and is chosen to be the difference between the mean and the 80th percentile of the output price distribution.

Based on the above, the methodology for the Maximum STEM Price and the Alternative Maximum STEM Price are presented below.

Maximum STEM Price

The Maximum STEM Price is based on the 80th percentile cost of the formula given by Equation 1.

In applying this formula, the Dispatch Cost is calculated using a gas price distribution (refer to Chapter 5) over all Monte Carlo samples.

Alternative Maximum STEM Price

The Alternative Maximum STEM Price is based on the 80th percentile cost of the formula given by Equation 1.

In applying this formula, the Dispatch Cost is calculated for a fixed distillate price over all Monte Carlo samples, and this calculation is repeated over an appropriate range of distillate prices. This enables a regression equation to be determined with a fuel independent ("non-fuel") component plus a "fuel" cost dependent component that is proportional to the net ex terminal distillate price.

Each month the Alternative Maximum STEM Price is calculated by substituting the current net ex terminal distillate price into the following regression equation:

Equation 2

$$Alternative\ Maximum\ STEM\ Price_{\$/MWh} = Constant_{\$/MWh} + \alpha_{GJ/MWh} \times Distilate\ Price_{\$/GJ}$$

Risk margin

The Risk Margin is intended to allow for the uncertainty in assessing the short run marginal cost of a candidate generation plant[9], including its fuel and non-fuel price components. It represents the difference between the upper Energy Price Limits and the function of the expected values of Variable O&M costs, Heat Rate and Fuel Cost.

The Risk Margin is established by inputting the mean values of each variable into the following equation:

Equation 3

$$Risk\ Margin\ = \frac{Derived\ Energy\ Price\ Limit_{\$/MWh}}{Mean\ Dispatch\ Cost_{\$/MWh}} - 1$$

2.2   Factors to be determined

Noting the variables to be determined from equations 1 and 2 above, and the application of the Risk Margin specified by equation 3, the methodology required the following to be determined:

- Selection of the Candidate Peaking Generators;
- Variable O&M for the Candidate Peaking Generators;

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[9] Clause 6.20.7(b)(i) of the WEM Rules

- Gas and Distillate price distributions;
- Heat Rate curve for Candidate Peaking Generators
- Loss Factors for Candidate Peaking Generators
- Statistical Modelling Methodology to Determining the Risk Margin.

These factors are discussed in detail in Chapter 3 to Chapter 8 of this report.

2.3 Other issues

2.3.1 Truncated Normal Distribution and Gamma Distributions

Some of the input distributions (e.g. gas price) used in the Monte Carlo simulations were truncated. If a normal curve is used to produce an input distribution, then this can result in negative values (depending on mean and standard deviation of the distribution) which may not be possible for input variables (e.g. gas price, MWh/start etc).

In these cases, the truncation of the input variable distribution may be required to yield sensitive results. Some truncation of the gas commodity and transport price distributions was required in this study to avoid negative (and extremely) low price outcomes.

As a normal distribution is symmetric around the mean of the distribution, the normal distribution has the property that the mode and mean value are identical. However, with the distribution truncated, the symmetry is broken, and the mean value will no longer be the same as the mode. Gamma distribution can also be asymmetric but with different modes and means.

2.3.2 Pseudorandom number generator

For each simulation, the Monte Carlo model uses the Microsoft Excel RAND() function to produce one random number for each distribution between 0 and 1. If the function was truly random, these numbers would be independent. However, all computers use a "Pseudorandom" generator. Excel uses a Mersenne Twister algorithm which is standard in many applications. With a very high number of simulations this could lead to repeating pattern. However with the 10,000 simulations used in the review this number is small enough that this will not be an issue.

3. Selection of the Candidate Peaking Generator

This chapter addresses the selection of the marginal gas generator. This is relevant to the input variables of Heat Rate, Variable O&M and Loss Factor which is generator unit dependent.

3.1   Review of Gas Generators

In previous studies, the upper Energy Price Limits have been based on the Pinjar 40 MW gas turbines (6 units). Other candidate generators included the Parkeston aero-derivative gas turbines (3 units) located in the Goldfields Region, and the Mungarra gas turbines (2 units) located in the North Country Region.

In May 2017, Synergy announced it would retire four generation assets in order to meet the terms of the direction handed down by the state government to reduce its generation cap to 2275 MW. This included the Mungarra Units, which were scheduled to retire on 30 September 2018.

In May 2018, the Network Operator (Western Power) determined that reliability obligations under the Technical Rules would not be met unless the Mungarra units provided a Network Control Service for the North Country Region (as well as the West Kalgoorlie units providing an equivalent service in the Eastern Goldfields Region[10]. These units are not being considered as candidate peaking generators.

> Box - Network Control Services
>
> A Network Control Service (NCS) is a service provided in accordance with Chapter 5 of the WEM Rules. Specifically, an NCS is a *"service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades" (Clause 5.1.1).* It is a contractual arrangement between Western Power and a Market Participant who owns the relevant generation plant. Western Power may call upon an NCS contract for network reliability purposes or to maintain voltage security in a region (e.g. when the electrical systems in those regions are effectively islanded, or there are other network outages).

On 1 October 2018, Western Power and Synergy entered into an NCS contract in relation to the Mungarra Units. As required under clause 5.2A.1 of the WEM Rules, the Mungarra Units are registered facilities in the WEM. However, the Mungarra Units do not have Network Access Rights (i.e. DSOC) except to support the provision of NCS, or to comply with a generation direction issued by AEMO when the SWIS is in an emergency operating state. . A Market Participant providing an NCS is paid by Western Power in accordance with the contract (except where the NCS facility is required to generate in response to a direction from AEMO when the SWIS is in an emergency operating state, in which case the Balancing Price is paid for energy provided under the normal WEM Rules settlement process).

In conclusion, since the Mungarra Units will not be dispatched in the WEM except under the terms of the NCS contract, or potentially under an emergency operating state scenario, it is considered that they are *not* a candidate facility for the "highest cost generating works" in the SWIS as required under clause 6.20.7(a) of the WEM Rules. The facilities will not set prices in the STEM or the Balancing Market. When an NCS is provided, the facilities will be compensated under the terms of the NCS contract by Western Power.

This is the same conclusion as in the 2019-20 review by Marsden Jacob, and we maintain the view that this conclusion remains appropriate for the current 2020-21 review.

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[10] Energy Policy WA, September 2018, Information Paper: Arrangements for continued power supply reliability in the North Country and Eastern Goldfields regions, https://www.wa.gov.au/sites/default/files/2019-08/Arrangements-for-continued-power-supply-reliability-in-the-North-Country-and-Eastern-Goldfields-regions.pdf

3.2 Candidate gas Generators

The WEM Rules stipulate that the candidate units must be 40 MW OCGT units[11]. The Heat Rate is a dominant factor in the determination of generation dispatch costs and is higher for smaller OCGTs.

The Pinjar and Parkeston Units are the smallest gas turbine units connected to the SWIS (excluding the Mungarra Units as outlined in Section 3.1) which implies that they will have higher Heat Rates when compared to other gas turbines connected to the SWIS. These units are listed in Table 1 below. They are then reviewed in turn below.

Table 1: Candidate OCGT units for setting upper Energy Price Limits

Unit	Maximum Capacity (MW)	Technology
PINJAR_GT1	38.5	Industrial GT
PINJAR_GT2	38.5	Industrial GT
PINJAR_GT3	39.3	Industrial GT
PINJAR_GT4	39.3	Industrial GT
PINJAR_GT5	39.3	Industrial GT
PINJAR_GT7	39.3	Industrial GT
PRK_AG Unit 2	37	Aero-derivative
PRK_AG Unit 3	37	Aero-derivative

Source: AEMO Facilities Data, Marsden Jacob analysis 2020

3.3 Pinjar Gas Generators

The Pinjar Units are owned and operated by Synergy and are used to provide peaking power in the SWIS. These units were fully operational by October 1990 and typically have had capacity factors of around 3%, although the capacity factor can vary significantly between units and across years. The capacity factor of the Pinjar Units has declined over time as other less expensive generator units have entered the SWIS (e.g. Alinta Wagerup, Kemerton, Perth Energy Kwinana GT1 etc). The average capacity factor of the units was below 2% between 2014 and 2018 but has increased in 2019 to be above 2%. These low capacity factors will increase the dispatch costs of the plant since the generators will typically operate at low output levels which increases the heat rate for the respective units.

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[11] Clause 6.20.7(b)(i)-(v) of the WEM Rules

Figure 1: Capacity factor range of Pinjar Units

● Pinjar -Average Capacity

Notes: 2007 financial year ending data only includes data commencing September 2006.

Source: AEMO Facility Scada Data, AEMO Facility Standing Data, Marsden Jacob analysis 2020

3.4 Parkeston Gas Generators

While the Pinjar Units have a definitive role as peaking units, the Parkeston Units provide electricity to a major mining customer in the Goldfields Region. The mining customer typically has an average energy requirement of around 40 MW baseload. This requirement is usually met by a single generation unit (PRK_AG Unit 1 in 2019) and imports from the SWIS.

The net exports for the Parkeston Power Station are shown for several years in Figure 2, which highlights that net exports are significantly lower in the last 8 years.

Figure 2: Net exports from the Parkeston Units

Source: AEMO Facility Scada Data, Marsden Jacob analysis 2019

The operating data for the Parkeston Units (net exports only) and Pinjar Units are presented in Table 2.

Table 2: Operating data for candidate OCGT units in the SWIS 2019

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
No. of Starts	296	44	33	36	38	31	44
Hours Operating	1392.5	524	435.5	369.5	480	409	413
Average Output (MW)	17.7	16.0	13.8	14.9	16.3	17.0	16.6
Annual Generation (MWh)	24682	8384	6009	5500	7804	6948	6843
Capacity Factor (%)	2.41%	2.5%	1.8%	1.6%	2.3%	2.0%	2.0%

Source: Marsden Jacob analysis 2020

3.5   Assessment of Selected Gas Generators

The analysis above shows that the Pinjar Units had between 31 and 44 starts in 2019 and operated for 438 hours a year on average. Compared to 2018 the operation of the Pinjar Units is appreciably up with the average length of generation per start increasing from 3 to 5 hours in 2018 to 9 to 12 hours in 2019. This increased generation per start is likely to have the effect of lowering variable costs on a per MWh basis.

Exports from the Parkeston Units have also increased in 2019 (24,682 MWh) compared to 2018 (12,795 MWh).

Table 3 highlights that only the Parkeston Units were able to capture on average, a higher Balancing Price than the Pinjar Units. The average Balancing Price for the Pinjar Units when operating decreased from 2018 which is expected due to the increased hours of operation.

Table 4 illustrates the volatility of the occurrence of maximum prices in the Balancing Market.

Table 3: Captured Balancing and STEM Prices ($/MWh, nominal) 2019

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
Average STEM Price When Running ($/MWh)	59.8	44.2	42.5	43.6	41.9	43.0	46.1
Average Balancing Price When Running ($/MWh)	72.5	47.5	48.3	40.4	44.7	50.4	57.4
Maximum Price Captured in STEM ($/MWh)	165.6	138.7	138.7	126.7	140.5	138.7	138.7
Maximum Price Captured in Balancing Market ($/MWh)	257.6	227.8	232.8	218.7	192.7	209.6	232.8

Note: "Captured" means the unit was operating when various prices were set in the Balancing Market and STEM.

Source: Marsden Jacob analysis 2020

Table 4: Occurrence of Maximum STEM Price in the Balancing Market

Financial Year	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Occurrences	23	5	22	0	26	0	3

Source: AEMO Balancing Summary Data, Marsden Jacob analysis 2020

Table 5 shows the average generation of the candidate OCGTs by ranges of Balancing Prices.

Table 5 Candidate OCGT average MW by price bands FY 2018-19

Balancing Price Range	Periods	PRK_AG	PINJAR_GT 1	PINJAR_GT 2	PINJAR_GT 3	PINJAR_GT 4	PINJAR_GT 5	PINJAR_GT 7
>300	3	24.49	0.00	0.00	0.00	0.00	0.00	0.00
250 - 300	8	8.21	0.00	0.00	0.00	0.00	0.00	0.00
200 - 250	6	8.32	0.00	2.24	0.00	2.23	2.53	7.84
150 - 200	123	6.82	0.97	0.81	0.17	0.69	0.00	1.04
100 - 150	670	7.49	0.97	1.50	0.45	0.73	0.25	0.78
50 - 100	3518	4.30	0.39	0.51	0.34	0.26	0.28	0.22
0 - 50	12624	0.32	0.13	0.26	0.12	0.11	0.07	0.08
<0	568	0.16	0.02	0.06	0.00	0.19	0.00	0.00

3.6 The Selected Gas Generators

In relation to the selection of the generator or generators we note the following:

- Of the candidate gas generators, the Parkeston Units were the only unit generating during the time of Maximum STEM Price. The Pinjar Units did not capture any price over $250/MWh in 2018-19.

- It is likely that the STEM and Balancing Market will be subject to increasing price volatility due to the increased penetration of both small and large-scale renewable generation in the SWIS.

- During periods of high intermittent non-scheduled generation (e.g. solar and wind facilities), Balancing Prices could go below zero for longer periods, while prices may be higher when scheduled generation is required to ramp up rapidly to meet demand when solar generation level falls in the evening period (in both winter and summer).

The above analysis illustrates that both the Parkeston Units and the Pinjar Units are suitable as the candidate generators to use in this study. This was the conclusion in the 2019-20 review.

As per the 2019-20 review, the generator units selected are:

- Parkeston Units: PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG; and

- Pinjar Units: the 6 Pinjar 40MW gas turbine units registered in the WEM as individual facilities PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5 and PINJAR_GT7.

4. Variable O&M Costs

This chapter presents the derivation of the Variable O&M costs for the Parkeston Units and Pinjar Units (i.e. for the selected generator units). This is done using their probability distributions and mean values.

4.1   Review of Variable O&M Costs

Variable O&M are those costs that vary with electricity generation. This includes:

▪   Variable operating labour costs;

▪   Usage-related maintenance costs (i.e. labour and materials);

▪   Non-fuel inputs such as lubricants and water.

Usage-related maintenance costs can be accelerated due to the frequency of start-ups and the duration of dispatch. Increasing the number of start-ups can also bring forward maintenance expenditure since additional wear and tear is incurred in frequently going from cold start to minimum (stable) generation levels.

Longer dispatch cycles will also require that maintenance cycles are brought forward to ensure that the generating unit is operating reliably and efficiently.

There are issues with factoring start-up costs (i.e. accelerated maintenance) into the determination of Variable O&M costs. These costs can be factored into the first half hour of dispatch on the basis that an OCGT is only guaranteed to be dispatched for the first Trading Interval that it operates, or these costs can be smoothed over several Trading Intervals based on its expectation of the number of trading intervals that it will operate for a given start (say 4.5 hours). In the latter case, there is no guarantee that the plant will recover its start-up costs if it operates for fewer hours (i.e. dispatch forecasts were wrong). In the former case, including all start-up costs in the generation offer for the first half hour of trading may result in the plant not operating sufficiently and foregoing profitable opportunities to operate in the market.

Standard practice would be to amortise the start-up costs over the expected number of hours of operation of the plant in a year (i.e. they have a probability distribution). However, Monte Carlo analysis will be required since there is uncertainty about the number of starts in a year and the average number of hours that a plant will be dispatched.

Variable O&M costs for OCGT plant in the WEM is based on engineering data available to Marsden Jacob, and includes:

▪   The Electric Power Research Institute (EPRI) study into power generation costs in Australia[12];

▪   Data that has been collected, analysed and benchmarked while undertaking market studies in the NEM, Northern Territory and WEM for numerous market participants and investors;

▪   Reports used to set upper Energy Price Limits in previous years; and

▪   Data from Synergy (owner of Pinjar Units) and Goldfields Power Pty Ltd (owner of Parkeston Units).

Marsden Jacob estimates of Variable O&M for both the Pinjar and Parkeston Units, and the triggers for this expenditure, are provided in Section 4.3.

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[12] Electric Power Research Institute, Australian Power Generation Technology Report, 2015

4.2   Maintenance Cycle

4.2.1   Maintenance cycle length

In Marsden Jacob's view, all the smaller and high operating cost Pinjar Units (GT1 to GT5 and GT7) are likely to remain in service until 2031, at which time they will be 40 years old and at the end of their useful lives. This end of service date for Pinjar Units is unchanged from the 2019-20 review. This implies that the maintenance program will need to ensure that the Pinjar Units remain operational until 2031. This has been factored into the determination of the maintenance cycle for the Pinjar Units.

In addition, the Parkeston Units are also likely to have a 40-year life, which implies that the units will be in service until at least 2036. A maintenance cycle for the Parkeston Units has been developed based on this expected plant life.

Estimates of significant overhaul costs have been obtained from both Goldfields Power Pty Ltd (Parkeston Units) and Synergy (Pinjar Units).

4.2.2   Average number of starts per year

The Variable O&M costs (including start-up costs) are based on a high heat rate because the unit is assumed to be operating at low output levels.

In the 2018-19 review, Perth Energy indicated that the General Electric (GE) manual "Heavy-Duty Gas Turbine Operating and Maintenance Considerations GER-3620M" states that if the machine is started and then run at low load, this being below 60% of full output, the factored start value for a GE Frame 6 is only one half of a start than where the machine then runs to full power.

For this study, Marsden Jacob has estimated number of starts with low loads only contributes 0.5 of a normal start, and this is consistent with the view from the 2019-20 review.

4.2.3   Future maintenance Costs

Based on the current method, future maintenance expenditures are discounted back to present value based on an appropriate real discount rate. Two methods were recommended by the ERA in previous reviews:

Method 1: This involves the use of a risk-adjusted discount rate based on the perceived riskiness of the future expenditures.

Method 2: This involves the use of Monte Carlo simulation. A Monte Carlo simulation can be run by drawing samples from distributions assigned to future maintenance expenditures. The characteristics of the assigned distribution are determined by the variability of future maintenance expenditures. The present value of drawn cash flows is then calculated based on a risk-free rate of interest. This yields a distribution for the present value of the future cash flows. A percentile of the distribution can be taken as the risk-adjusted present value of future maintenance expenditures.

The previous reviews moved from Method 1 in 2017-18 to Method 2 in 2018-19. In the view of Marsden Jacob, both methodologies are sound, although the Monte Carlo method will yield a more rigorous and likely more accurate estimate of maintenance expenditure costs.

In line with the approach for the previous 2019-20 review, for this study used Method 2. Future maintenance expenditures have been discounted using a real pre-tax WACC of 5.8%, which is based on estimates provided by the Independent Pricing and Regulatory Tribunal (in New South Wales) in regulatory price determinations (February 2020).[13]

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[13] Sourced from the Independent Pricing and Regulatory Tribunal, "Spreadsheet-WACC-model-February-2020.xls".

4.3   O&M Cost Determination

To calculate O&M costs, it has been assumed that the Pinjar and Parkeston Units have 40 year lives. This implies that O&M costs were calculated on the basis that the Pinjar Units are retired by 31 December 2031 and that the Parkeston Units are retired by 31 December 2036.

4.3.1   Approach

O&M costs for the units have been derived using the following four steps.

Step 1: determine a point estimate of maintenance costs per start based on (confidential) data provided by both Synergy and Goldfields Power Pty Ltd. The relevant costs range from $2,500 to $5,000 per start and are summarised below:

- Pinjar Units: $ ▮▮▮ per start

- Parkeston Units: $ ▮▮▮ per start

While these point estimates of start costs are useful reference points, to calculate the mean Variable O&M cost per start and risk margin (based on the 80th percentile of Maximum STEM Prices), a distribution of maintenance costs per start needs to be calculated. In the process of developing probability density functions for the number of starts, dispatch event MWh and Variable O&M per MWh, the resulting mean Variable O&M cost per start may differ from the above point estimates.

Step 2: create a distribution of start costs ($/Start) given that the number of starts can vary which will change the overhaul maintenance cycle and hence the VOM costs per start. The probability density function for the number of starts was developed by fitting a gamma distribution to the historical distribution of starts per year.

Step 3: determine the relationship between the number of starts, which is the driver for maintenance overhaul costs. For the Parkeston Units this was based on costs in previous reviews but has been updated for exchange rate movements (impacts cost of imported parts) and local inflation (local labour and recycled parts). For the Pinjar Units the annual maintenance costs per unit provided by Synergy was used.

Step 4: determine the distribution of dispatch event MWh (generation) equal to or less than 6 hours. In previous reviews of Energy Price Limits, it was argued that the Maximum STEM Price needs to cover short dispatch periods (less than 6 hours) with high prices, rather than considering longer dispatch intervals with lower prices.
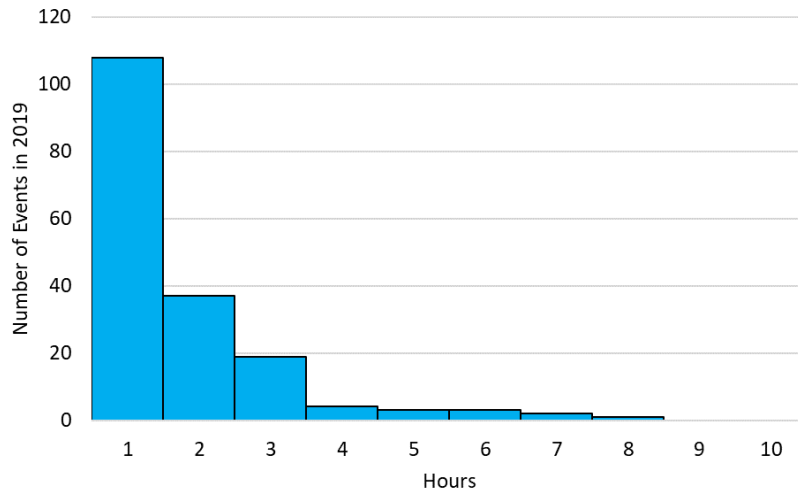
Variable O&M also includes other inputs such as water, labour and lubricants these costs have been estimated by increased by Marsden Jacobs to be $1.50/MWh for an OCGT plant.

4.3.2   Number of Events where Balancing Price continually exceeded $100/MWh in 2019

As noted above, the length of high Balancing Price events is relevant to the amortisation of start-up costs to a generator unit.

Figure 3 presents the number of occurrences of Balancing Prices exceeded $100/MWh in 2019 and for how many hours this lasted. Many of the events that last for less than 3 hours occur on the same day with a small lower price period in between. A 6 hour period of operation is capable of covering a multiple of these short events without restarting the unit.

Figure 3 Number of events where Balancing Price continually exceeded $100/MWh in 2019
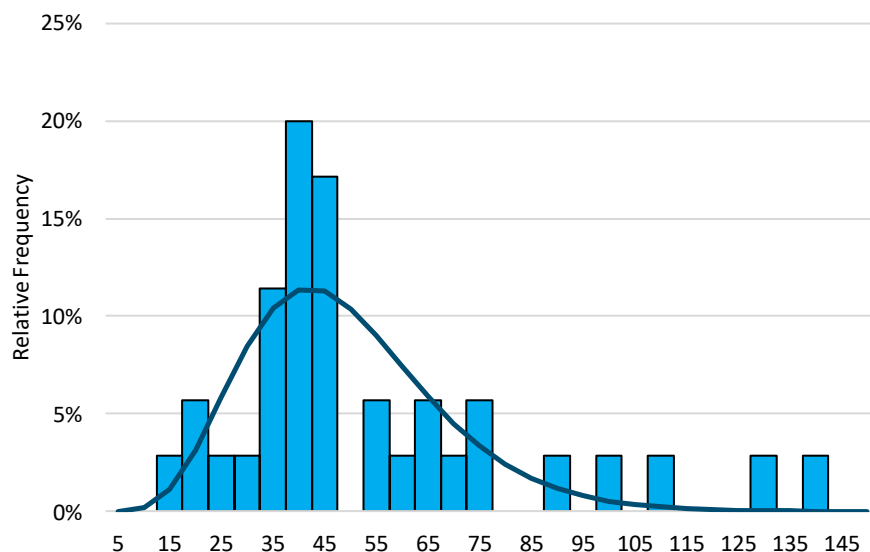

Source: *Marsden Jacob analysis 2020*

4.3.3 Pinjar Units O&M Costs

The estimates of dispatch event (per MWh) for the Pinjar Units is based on the dispatch profile of all six units over the period 1 January 2014 to 31 December 2019.

Dispatch event MWhs have a gamma distribution fitted and used in the development of Variable O&M costs per MWh. The use of a gamma distribution is a change from the 2019-20 review which previously used a normal distribution. Analysis of the results showed that the higher operation of Pinjar Units in 2019 fit better with the a less symmetrical gamma function that allows for a higher occurrence of high generation levels.

Table 6 presents a summary of Pinjar Units O&M Starts. Based on this, Figure 4 below shows the distribution of the number of starts between 1 January 2014 and 31 December 2019 and a fitted gamma profile for all Pinjar Units.

Figure 4: Distribution of the number of starts – Pinjar Units

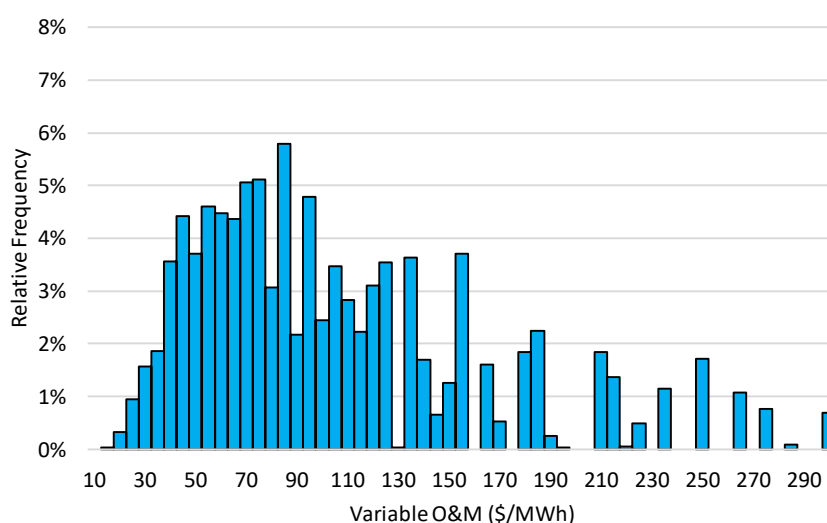*Source: Marsden Jacob analysis 2020*

Table 6: Summary of O&M starts – Pinjar Units

Measure	Unit	Dispatch Events
Mean	Starts/year	54
Minimum	Starts/year	12
Maximum	Starts/year	153
Operating Hours	Hours/Start	3.6

The Variable O&M per Start distribution has changed from the 2019-20 review. As part of the 2020-21 review, Synergy has provided an annual estimate of maintenance cost per unit for the Pinjar Units. This annual cost is fixed independent of the number of starts so higher starts results in lower cost as there are more starts to distribute the fixed value across. In the 2019-20 review a high number of starts would bring forward scheduled maintenance increasing costs per start.

Figure 5 below displays the distribution of Variable O&M costs for the Pinjar Units used in the Monte Carlo modelling.

Figure 5: Distribution of Variable O&M Costs ($/MWh) – Pinjar Units

Source MJA analysis 2020

4.3.4   Parkeston Units O&M Costs

Table 8 presents a summary of Parkeston Units O&M Starts.

The benchmark overhaul costs and unit start costs are shown in Table 7 for Parkeston Units. The overhaul costs are the same as used in the 2019-20 review adjusted for local and international inflation costs and changes to the WACC. The NPV of starts is based on calendar year 2019 operation of Parkeston Units.

Table 7: Overhaul costs and levelised cost per start for Parkeston Units – 15 Year Life

Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul	Number in an overhaul cycle	Cost	Average of NPV of Overhaul Costs $
A	600	$1,324,213	1	$1,324,213	
B	1200	$3,500,579	1	$3,500,579	
A	1800	$1,324,213	1	$1,324,213	
C	2400	$5,055,839	1	$5,055,839	
Total Cost		$11,204,843		$11,204,843	$4,726,853
Cost Per Start (a)		$4,668.68	Levelised Cost Per Start (b)		$3,244.24
Starts / Year		137	NPV of Starts		1457

Notes: (a) Total Cost divided by 2400 starts (consistent with previous reviews)

(b) NPV of Overhaul Costs divided by NPV of Starts

Source: Marsden Jacob analysis 2020, Jacobs Group (Australia) Pty Ltd 2018
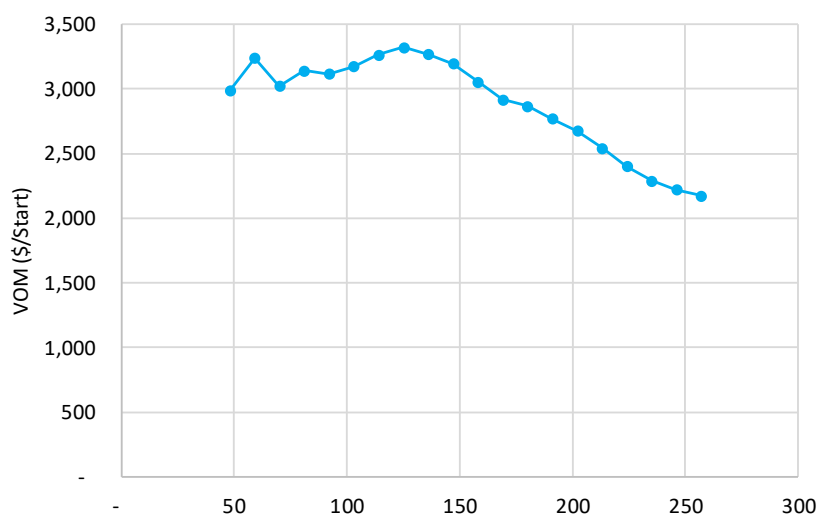
Figure 6 below displays the average Variable O&M costs per start for the Parkeston Units.

Figure 7 presents the resulting distribution of Variable O&M costs for the Parkeston Units.
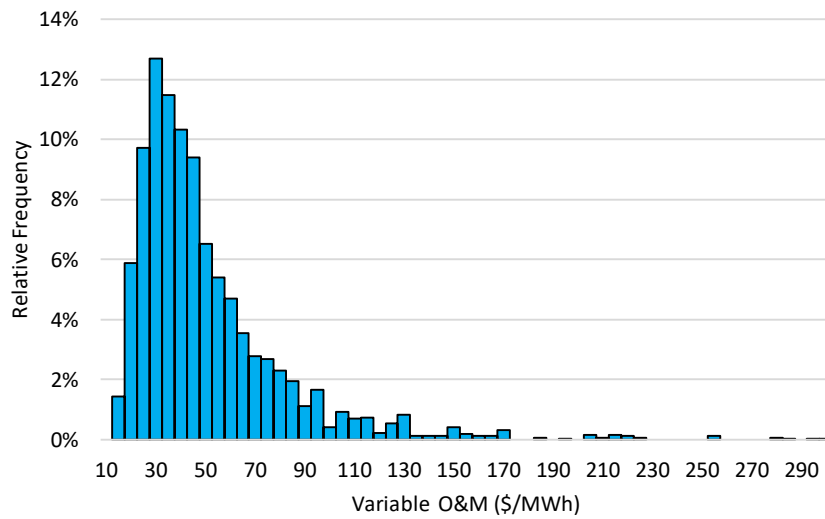
Table 8: Summary of O&M Starts – Parkeston Units

Measure	Unit	All Dispatch Events
Mean	Starts/year	216
Minimum	Starts/year	15
Maximum	Starts/year	275
Operating Hours	Hours/Start	3.76

Figure 6: Relationship between Variable O&M costs per start and number of starts – Parkeston Units

Source: Marsden Jacob analysis 2020

Figure 7: Distribution of Variable O&M costs ($/MWh) – Parkeston Units

Source: Marsden Jacob analysis 2020

5. Heat Rates

This chapter presents the Heat Rates used for the Pinjar and Parkeston Units.
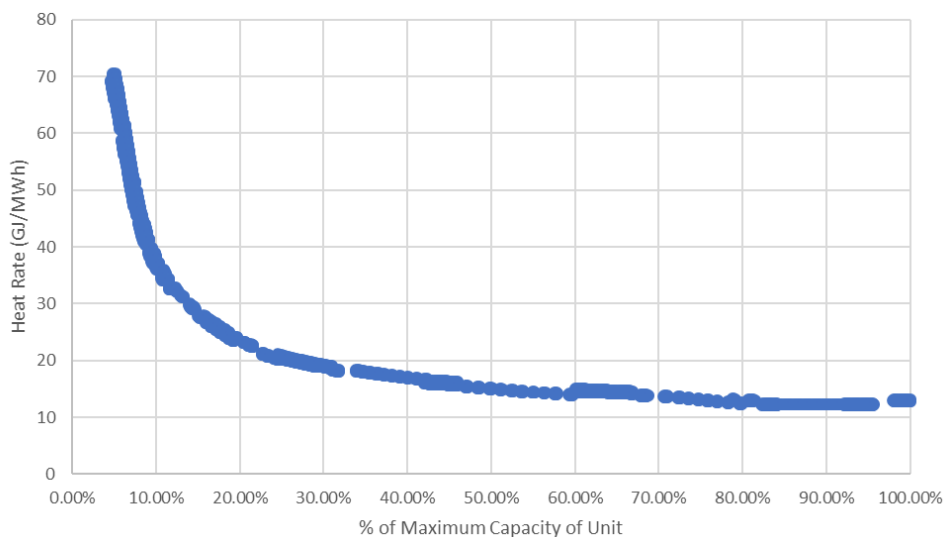
5.1.1 OCGT Heat Rates

Heat Rate curves for these units have been sourced from Synergy (Pinjar Units) and Goldfields Power Pty Ltd (Parkeston Units) as owners of the respective units.

Fuel start-up costs have been factored into the plant Heat Rates. This includes fuel use associated with starting up the unit (from cold start), idling, and ramping up the unit to minimum (stable) generation levels.

The Heat Rate curves show how unit heat rates vary with generation output (no temperature adjustments since there is less than a 1% impact on the heat rate between high and low temperatures).

Figure 8 shows the typical Heat Rate of a 40 MW OCGT units (similar to the Pinjar Units) based upon the percentage loading (MW) of the generator (compared to nameplate capacity of the plant).

Figure 8: Typical Heat Rate of 40 MW OCGT units – 15°C/ 30% humidity

Source: Marsden Jacob analysis 2019

5.1.2 Start-Up Energy Consumption

Start-up heat energy was assumed to average between 10 to 15 GJ/Start for each turbine. Start-up energy consumption is aggregated across all generation for that start.

For a Pinjar Unit operating at 75% capacity utilisation, the ▮▮▮ GJ used to start the turbine less than the operation for a single MWh. For most simulated starts, this cost accounts for less than $2/MWh of the Maximum STEM Price.

6. Loss Factors

Loss Factors are used to determine the quantity of sent out electricity that is delivered from a generator to a reference node. The SWIS has only one reference node, which is defined as the Muja 330 bus-bar[14].

A Loss Factor less than unity implies that less electricity is delivered to the node than what is injected into the transmission network and vice versa if the Loss Factor is greater than unity. The Loss Factor at the reference node is 1.

Table 9 below lists the Loss Factors for the 2019-20 financial year for the Pinjar and Parkeston Units.

Parkeston loss factor is significantly higher than that for Pinjar and has the fourth highest Transmission Loss Factor (TLF) in the SWIS.

Table 9: Loss Factors for Pinjar and Parkeston Units

Loss Factor Area Code	Description	Loss Factor	Start Date
WPJR	Pinjar Units	1.0369	1-Jul-19
WPKS	Parkeston Units	1.1633	1-Jul-19

Source: Western Power, 2019-20 Transmission Loss Factors

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[14] Chapter 11 of the WEM Rules

7. Gas and Distillate Costs

This chapter presents the costs of gas and distillate used on the modelling.

Gas costs are important as dispatch costs are highly dependent upon fuel price assumptions. As most OCGT plant operate at a thermal efficacy less than 32%, a $1/GJ change in fuel price results in a $11.25/MWh change in dispatch costs in a trading interval.

The Maximum STEM Price is calculated based on the dispatch costs of a 40 MW OCGT using natural gas, while the Alternative Maximum STEM Price is calculated based on the dispatch costs of a 40 MW OCGT using distillate[15]. In this section, the methodology for determining delivered gas and distillate prices is outlined.

Presented in turn below are the following:

- Gas:
    - Commodity Costs
    - Determination of Gas Cost Distribution
    - Gas – Transport Costs.
- Distillate Prices
    - Distillate Prices Distribution.

7.1 Gas – Commodity Costs

The wholesale gas market in Western Australia is based on bilateral trading between gas producers and major buyers. Many of these transactions take the form of long-term gas sales agreements (5 to 20-year contracts) that include annual and daily maximum quantities and annual minimum quantities (i.e. "take-or-pay" (ToP) volumes).

Gas shippers (buyers) nominate daily quantities to be injected into pipelines on their behalf (up to the maximum limit) based on what they intend to withdraw, and imbalances are managed by adjusting subsequent nominations up or down. If cumulative imbalances exceed a threshold, the pipeline may charge a penalty.

Shorter-term gas trading arises when gas market participants want to vary their offtake volumes above contracted maximum levels or below ToP levels. While there is no centralised gas spot market in Western Australia, there are currently three third party exchanges that can trade gas on a short-term basis:

- The Inlet Trading market operated by DBNGP (WA) Transmission Pty Ltd at the inlet to the pipeline, which enables pipeline shippers to trade equal quantities of imbalances.

- The gasTrading platform, which enables prospective buyers and sellers to make offers to purchase and bids to sell gas on a month-ahead basis at any gas injection point. gasTrading matches offers and bids and the gas is then scheduled, with subsequent daily adjustments.

- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine members, but usage of the platform is unknown.

It should also be pointed out that most gas is traded informally between the major gas buyers and sellers in Western Australia. There is a high concentration of both major buyers and sellers which implies that each party can simply enter into bilateral spot transactions on a daily, weekly or monthly basis.

Data from gasTrading's website is publicly available. For the past two years, typical volumes traded range from 5 to 25 TJ/day (0.5 to 2.0% of Western Australian domestic gas volumes) and prices paid range from $2.50 to
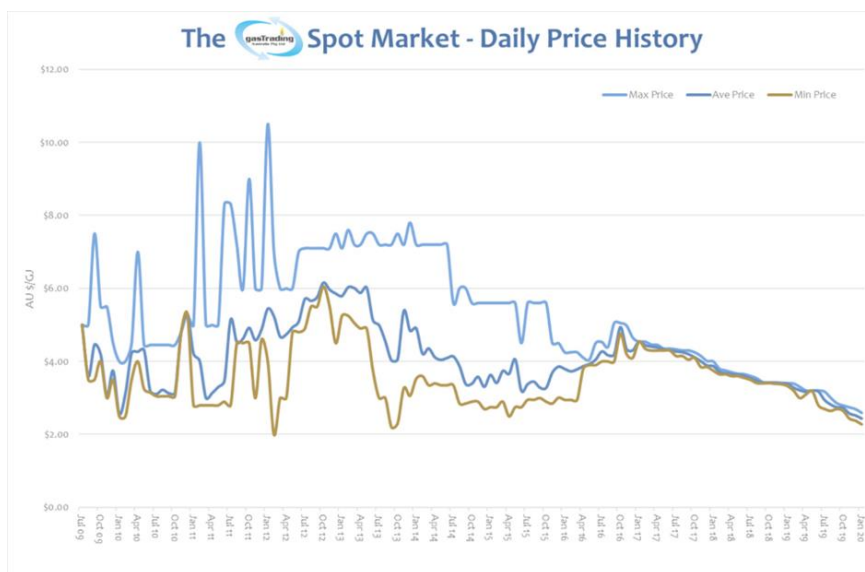
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[15] Chapter 11 of the WEM Rules

$4.15/GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.

Past reviews used the historical price data from gasTrading in the development of a spot gas price that could be used in the determination of the Maximum STEM Price.

Daily spot gas prices are shown in Figure 9 and indicate that maximum, minimum and average prices have converged in recent years, reflecting the oversupply of domestic gas capacity and reserves.

Despite the limitations of only using gas price data from a single source with relatively low trading volumes (gasTrading), the average gas prices have been reflective of the underlying value of gas to major participants in the market.

Figure 9: Daily spot gas prices in Western Australia ($/GJ, nominal)

Source: gasTrading website[16]

The forecasts of gas commodity prices using the gasTrading data is provided in section 7.2.

7.2   Determination of Gas Cost Distribution

Under earlier approaches[17], short-run projections of maximum gas prices were developed using an ARIMA model of historical maximum monthly prices. The projections were then used as the central estimate for each month with historical variation in prices used to generate the standard deviation. A normal distribution was assumed to exist for projected prices.
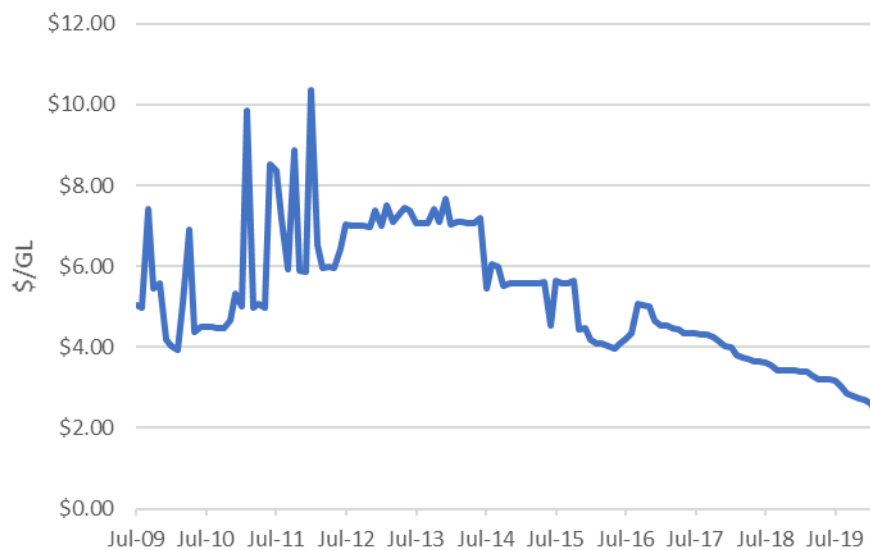
For this analysis Marsden Jacob has adopted a similar approach. Variations from the approach are explained below.

As indicated in Figure 10, maximum prices exhibited significant volatility up to the first few months of 2012. Since then between mid 2012 and the end of 2015, maximum prices were broadly constant with one step change in July 2014. Since the end of 2016, maximum prices have slowly but fairly continuously declined.

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[16] http://www.gastrading.com.au/spot-market/historical-prices-and-volume, downloaded March 2020.
[17] Jacobs (2018)

Figure 10: Historical maximum gas prices

Source: gasTrading Australia, various Access dates[18]

The analysis considered different forms of an ARIMA[19] model allowing for up to:

- Two levels of differences;
- 4 auto-regressive lagged errors;
- 4 moving average lagged errors.

The analysis also considered a constant term. This would reflect either an average level (no differencing), a growth factor (first differences) or an acceleration factor (second differences).

At the time of the 2019 analysis, Marsden Jacob's analysis of the gas market indicated that declines over recent years have reflected significant capacity coming online. This has resulted in two effects:
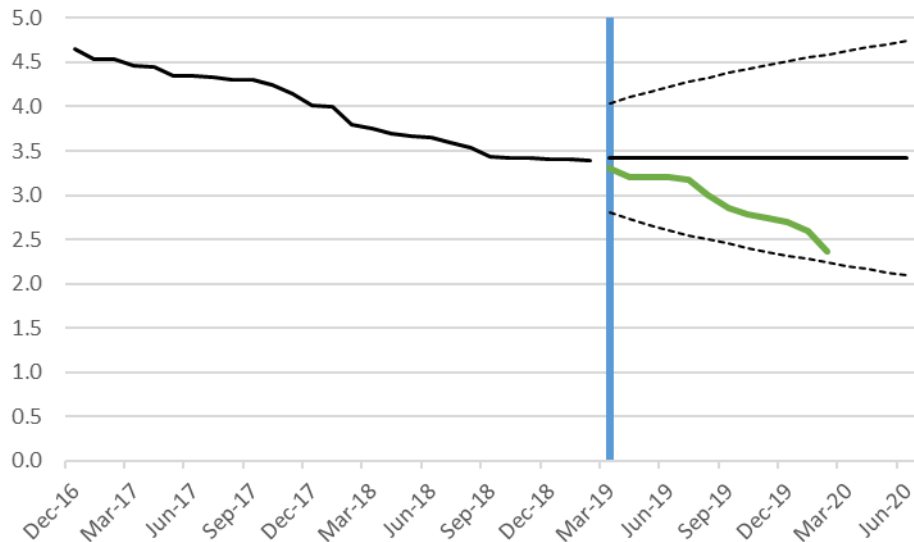
- Firstly, levels have declined. Marsden Jacob considers that the declines observed over recent years have incorporated the impact of the increase in capacity. We do not consider there is significant scope for further declines, particularly as prices approach the $2/GL floor;

- Secondly, there has been a significant reduction in volatility of maximum prices over the past few years. The significant *volatility before 2012 is considered to be unlikely to be replicated.*

Figure 11 shows our projections from 2019 and the actual course of maximum prices during the year. While within the bounds provided, it suggests that a $2/GL maximum price floor may be tested.

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[18] http://www.gastrading.com.au/spot-market/historical-prices-and-volume/13-historical-prices-and-volume/27-price-history-table
[19] Auto Regressive Integrated Moving Average

Figure 11: 2019 analysis of historical gasTrading monthly maximum prices, ARIMA forecast and actuals ($/GL)
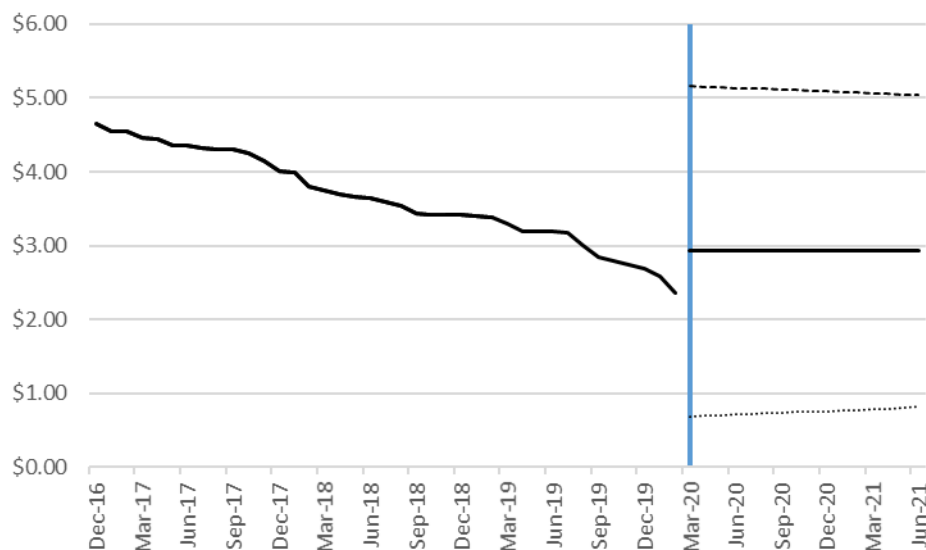

Source: gasTrading and Marsden Jacob analysis

The 2019 analysis suggested a single lag moving average model with one level of differencing (consistent with a slowly constantly declining price. The 2020 statistical analysis found that a model again with slight negative growth (constant with first differences) but using logs and with two lags for both AR and MA produced the 'best' outcomes.

Marsden Jacob continues to consider that $2/GL remains a reasonable approximation of the floor.

Marsden Jacob used the "best" ARIMA to generate estimates of volatility. This was used to generate standard errors for the estimates. For the purposes of projections for 2020-21, we consider the average of the past year to provide the best estimate of the expected value for the coming year.

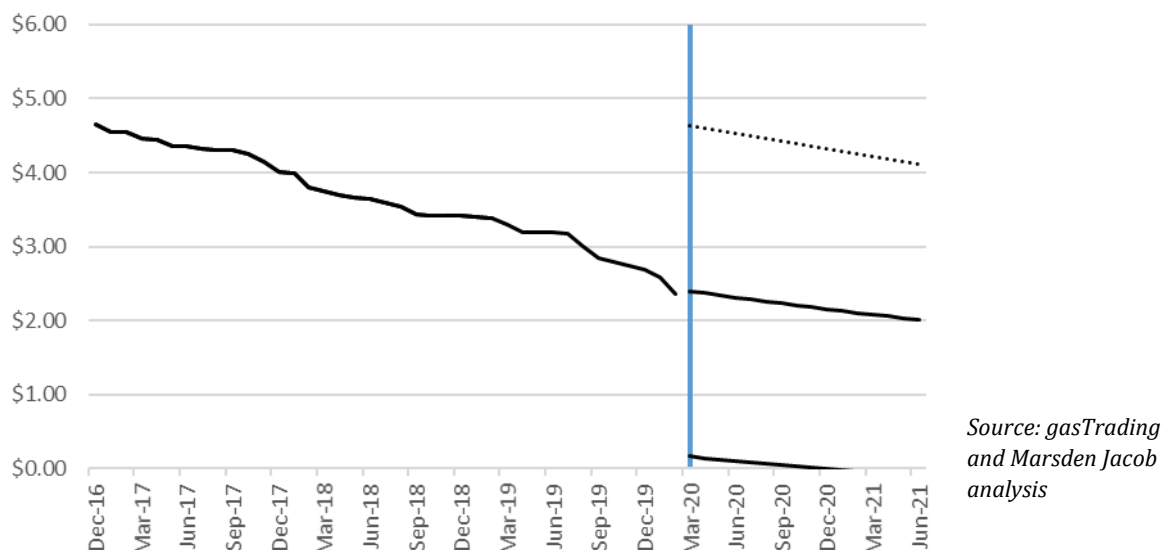Figure 12 shows these projections and the upper and lower bounds.

Figure 12: Projections of maximum gas prices 2020-21

Source: gasTrading and Marsden Jacob analysis

Figure 13 shows the projections based on the raw ARIMA model. As can be seen, this shows continued declines towards $2/GL.

Figure 13: Non-preferred projections

Source: gasTrading and Marsden Jacob analysis

7.3   Gas – Transport Costs

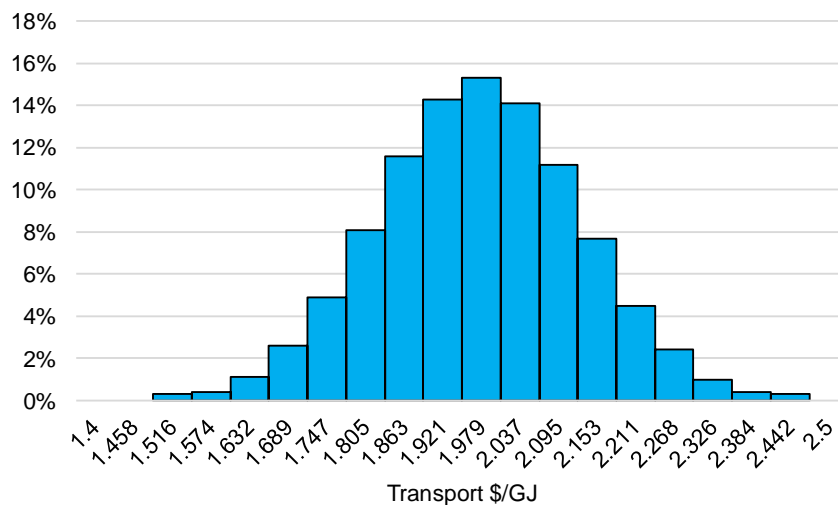The mean value for gas transport charges for gas delivered to both the Pinjar and Parkeston Units has been calculated:

- Pinjar – $1.557/GJ (based on a 15% premium above the T1 Reference Tariff[20] applicable on the Dampier to Bunbury Natural Gas Pipeline). Assuming a standard deviation of $0.15/GJ.

- Parkeston – $1.45/GJ (based on the purchase of spot transport for covered services on the Goldfields Gas Pipeline) with a standard deviation of $0.15/GJ.

The above gas transport charges assume the generator is operating at a 100% capacity factor daily.

However, it is likely that peaking gas generators will not be operating at this level and gas transport charges have been adjusted on the basis that the daily capacity factor is closer to 80% for gas turbines. At this level, gas transport charges would be $1.95/GJ on the Dampier to Bunbury Natural Gas Pipeline instead of $1.557/GJ, and $1.81/GJ on the Goldfields Gas Pipeline instead of $1.45/GJ.

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[20] https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/tariff-variations

Figure 14 Distribution of gas transport costs

Source *ERA and Marsden Jacob analysis*

7.4   Distillate Prices

The Alternative Maximum STEM Price is based on distillate prices (i.e. diesel)[21].

Diesel is typically imported from Singapore, which makes the delivered cost of Singapore diesel (0.5 per cent sulphur) the relevant benchmark for determining Energy Price Limits in the WEM. The Perth Terminal Gate Price (net of GST and excise) is the relevant benchmark for this study. Road transport costs from the BP refinery and port (ex-terminal) to both the Pinjar and Parkeston Units have been factored into the delivered distillate price for both candidate plants.

The WEM Rules permit the Alternative Maximum STEM Price to be updated monthly to enable changes in oil prices to be passed through (with a lag) into wholesale electricity prices[22]. This reduces the level of uncertainty for establishing Alternative Maximum STEM Prices.

Forecasts of world oil prices (e.g. Brent Crude) are available from a range of sources (e.g. World Bank, US Energy Information Administration etc) and have been used to develop ex-terminal Singapore diesel based on known relationships between world oil prices and landed diesel prices in Australia.

The distillate price forecasts are provided in Section 3.3.3.

7.5   Distillate Prices Distribution

The WEM Rules provide for a monthly re-calculation of the Alternative Maximum STEM Price based on assessment of changes in the Singapore gas oil price (0.5% sulphur) or another suitable published price as determined by AEMO[23]. AEMO uses the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore gas oil price (0.5% sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and as such considers variations in these costs due to factors such as exchange rate changes. Therefore, in this analysis a reference distillate price based upon the Perth Terminal Gate Price is assessed to define a benchmark Alternative Maximum STEM Price component that depends on the underlying distillate price.

For this purpose, the uncertainty in the distillate price is not statistically important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price,
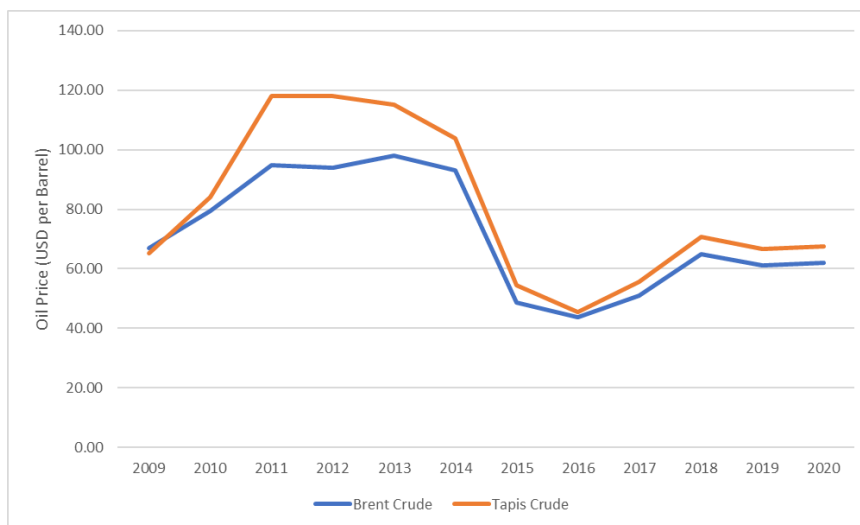
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[21] Chapter 11 of the WEM Rules
[22] Clause 6.20.3(b) of the WEM Rules
[23] Clause 6.20.3(b) of the WEM Rules

the uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the Dispatch Cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location. The following discussion describes the expected level and uncertainty in the distillate price for capping the gas price.

Figure 15 shows annual average crude oil prices. After the low prices of 2016, prices climbed in 2017 and 2018. The US Energy Information Agency[24] has forecast that Brent Crude, after averaging USD 59 per barrel in January, will average USD 61 per barrel in 2019 and USD 62 per barrel in 2020, after averaging USD 71 per barrel in 2018. The lower oil price outlook is due to the impact of increased oil production in the US and consequently less imports, and the US becoming a net exporter of oil in the 4th quarter of 2020.

Figure 15: Crude oil prices (USD per barrel) – annual average prices

Source: Marsden Jacob analysis 2019

Tapis Crude is imported into Australia from Singapore and directly impacts the terminal gate price of petroleum products and diesel in Australia. While independent forecasts of Tapis Crude were not available, there is a relationship between Brent Crude and Tapis Crude prices. In recent times, Tapis Crude trades at around a 9% premium to Brent Crude. Using this relationship, Tapis Crude prices will average USD 67.10 per barrel in 2019-20.

To derive a distillate price forecast that reflects the above movements in crude oil prices, the following measures were calculated:

▪ Using the above forecast of Tapis Crude, derive the USD 2019 and 2020 Perth Terminal Gate Price. Convert into AUD using an exchange rate of AUD 1 = USD 0.71 (current exchange rate);

▪ Remove GST and the Diesel Excise to derive a Terminal Gate Price that would be paid by local generators;

▪ Add in the cost of transport from the Kwinana refinery to the generation plant;

▪ Convert the delivered cost of distillate into a price in $/GJ.

The outputs are shown in Table 10. In effect, gas prices used to set the Maximum STEM Price should not exceed $21.75/GJ (Pinjar delivered distillate cost). The standard deviation of distillate prices is estimated to be $0.48/GJ.

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[24] EIA March 2019 outlook: https://www.eia.gov/outlooks/steo/

Table 10: Reference distillate prices for Pinjar and Parkeston Units 2020-21

Prices and Taxes	AUD cents per litre (ACPL)	AUD/GJ
Diesel TGP	135.6	
Excise	42.3	
GST	9.33	
Diesel TGP	84.0	21.75
Delivery Cost to Pinjar	1.2	
Delivery Cost to Parkeston	1.1	
Delivered Cost to Pinjar	85.2	22.06
Delivered Cost to Parkeston	85.1	22.04

Source: Marsden Jacob analysis 2020
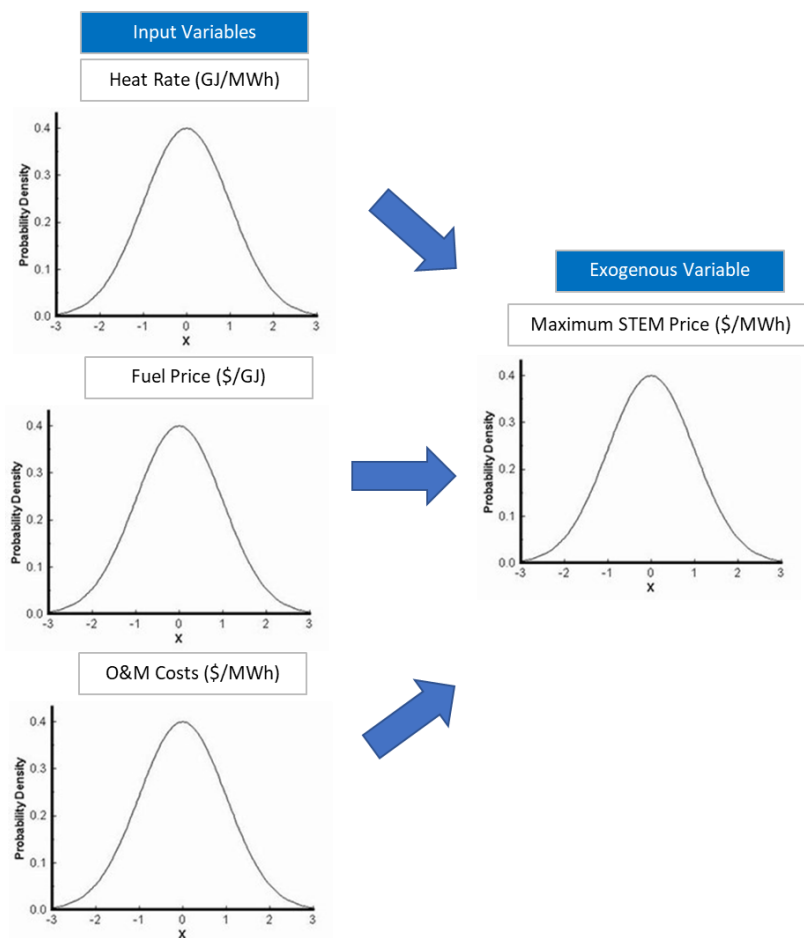
8. Statistical Modelling and Risk Margin

This chapter presents the statistical modelling undertaken.

As outlined earlier, there is considerable uncertainty regarding many of the variables that make up the formula for the Energy Price Limits. This includes the heat rate of the benchmark unit, Variable O&M, and fuel cost (i.e. gas and distillate prices).

Using statistical methods, Marsden Jacob have generated probability distributions for each of the key input variables that are uncertain (see Chapter 3). Figure 16 shows that the input variables have normal distributions, but this is not necessarily the case. Input variables could have normal, log-normal, uniform or triangular distributions, and in some cases could be truncated (i.e. input values cannot take certain values).

During a Monte Carlo simulation, values are sampled at random from the input probability distributions. Each set of samples is called an iteration, and the resulting outcome from that sample is recorded. Marsden Jacob has undertaken 10,000 iterations of the model to generate the probability distribution of possible Maximum STEM Price outcomes.

Figure 16: Monte Carlo simulations used to generate Maximum STEM Price probability density function
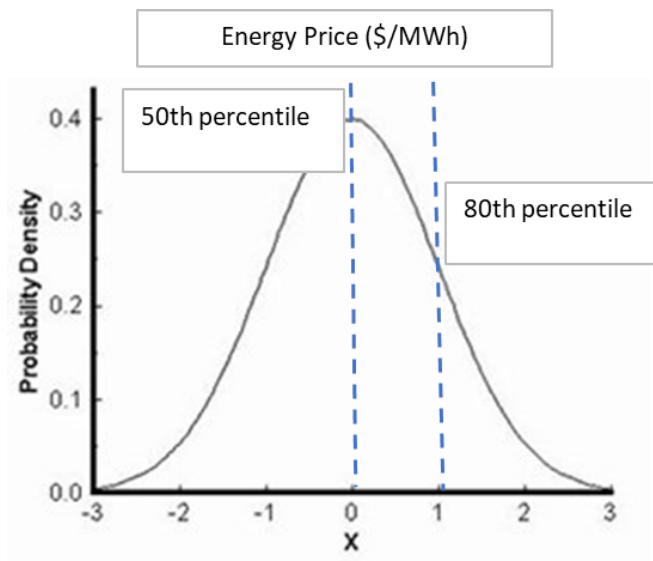

Source Marsden Jacob 2019

Once the distributions of likely maximum prices in the STEM/Balancing Market are determined, using the 80th percentile threshold, the Maximum STEM prices that covers 80% of occurrences in the WEM can be set.

The Risk Margin is also determined since it is simply the difference between the mean and the 80th percentile (see Figure 17 below).

Figure 17: Decision rule for determining Maximum STEM Price (80th percentile) and Risk Margin

Source Marsden Jacob 2019

9. Modelling Results

This chapter presents the modelling results for determining the Maximum STEM Price and Alternative Maximum STEM Price when based on the Parkeston Units and Pinjar Units.

In relation to the modelling:

- The results are based on the outcome of 10,000 simulations;
- Each unit is run independently and the potential generation outcomes for the Pinjar Units have no impact on the operation of the Parkeston Units and vice versa;
- Six random variables are created for each simulation;
  - Fuel commodity cost ($/GJ)
  - Fuel transport cost ($/GJ)
  - Start up Fuel (GJ/Start)
  - Variable O&M ($/MWh)
  - Average generation (MW) when dispatched
  - Run hours (h);
- Mean heat rate is a function of the average dispatch generation which is based on historical generation from 2014-2019 for Pinjar Units and 2019 for Parkeston Units;
- Fixed start-up costs are aggregated over all generation (MWh) for that start (Average Generation (MW) x Run Hours (h)).

9.1 Maximum STEM Price

The modelling results for the Maximum STEM Price for the Pinjar Units and Parkeston Units are presented in turn as follows:

Pinjar Units

- Table 11 presents the calculation of Maximum STEM Price;
- Figure 18 presents the Maximum STEM Price probability density function (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

Parkeston Units

- Table 12 presents the calculation of Maximum STEM Price;
- Figure 19 presents the Maximum STEM Price probability density function. (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

From the above results, the calculated Risk Margin, which is the difference between the mean and 80th percentile, is provided in Table 13.

A comparison of the results for Pinjar and Parkeston shows that there are large differences in the Maximum STEM Price between the use of Parkeston and Pinjar Units in establishing the Energy Price Limits.
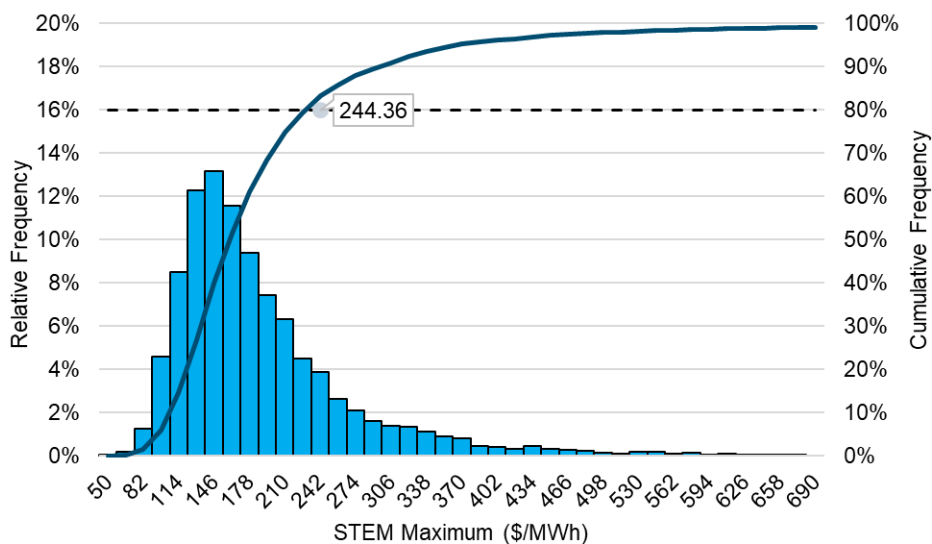
The lower average dispatch of the Pinjar Units (49.1 MWh per dispatch event) results in the plant operating at higher points on the heat rate curve when compared to the Parkeston Units (93 MWh per dispatch event).

Table 11: Calculation of Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.19
Mean Fuel Cost (heat rate adjusted)	$/MWh	108.78
Loss Factor		1.0369
Before Risk Margin	$/MWh	211.45
Risk Margin Added	$/MWh	32.90
Risk Margin Value	%	15.56
Assessed Maximum STEM Price	$/MWh	244.36

Source: Marsden Jacob analysis 2020

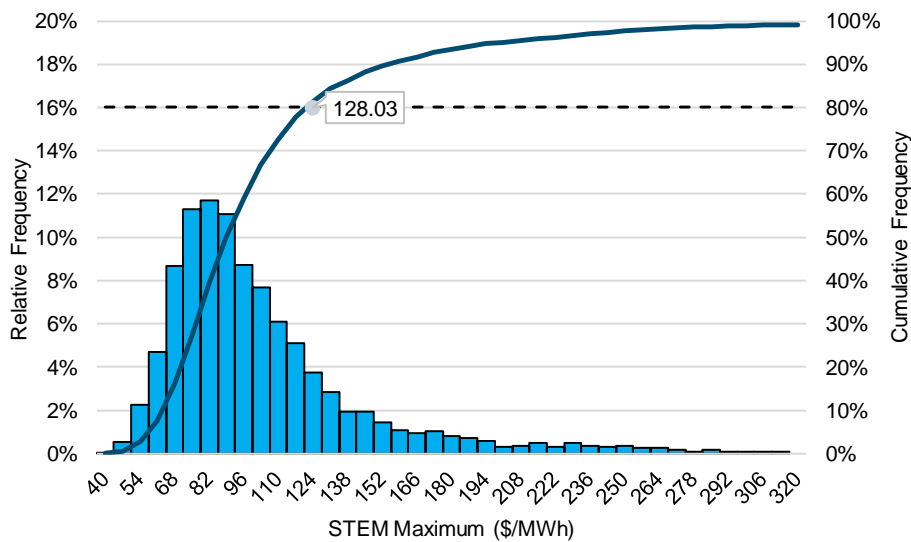## Figure 18: Maximum STEM Price probability density function – Pinjar Units

Source: Marsden Jacob analysis 2020

Table 12: Calculation of Maximum STEM Price – Parkeston Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	50.55
Mean Heat Rate	GJ/MWh	15.31
Mean Fuel Cost (heat rate adjusted)	$/MWh	76.70
Loss Factor		1.1633
Before Risk Margin	$/MWh	109.39
Risk Margin Added	$/MWh	18.64
Risk Margin Value	%	17.04
Assessed Maximum STEM Price	$/MWh	128.03

Source: Marsden Jacob analysis 2020

.

Figure 19: Maximum STEM Price probability density function – Parkeston Units

Source: Marsden Jacob Analysis 2020

Table 13: Risk Margin

Generating Units	Mean	80% Cost Coverage	Risk Margin
Pinjar Units	211.45	244..36	16.98
Parkeston Units	109.39	128.03	19.45

Source: Marsden Jacob Analysis 2020

9.2   Alternative Maximum STEM Price

The modelling results for the Alternative Maximum STEM Price for the Pinjar and Parkeston units are presented in turn as follows:
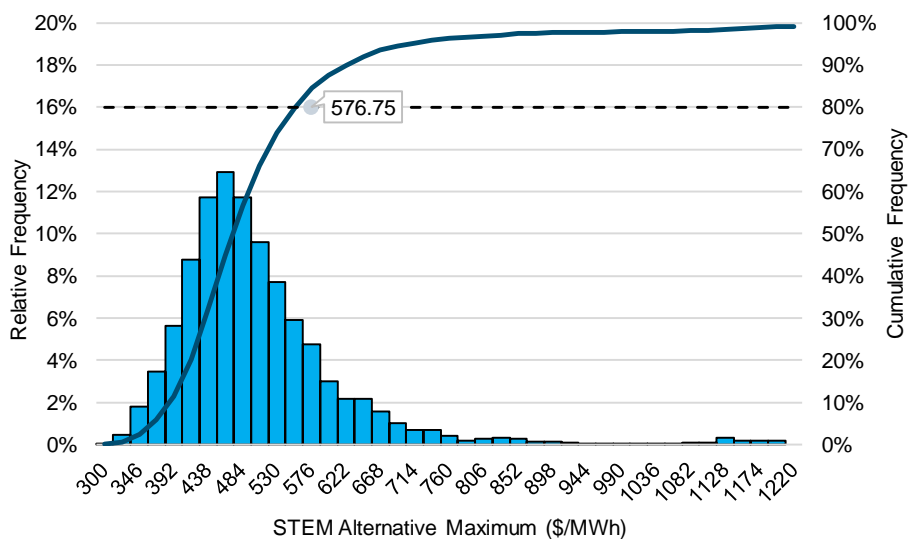
Pinjar Units

- Table 14 presents the calculation of the Alternative Maximum STEM Price;
- Figure 20 presents the Alternative Maximum STEM Price probability density function (this shows the 80th percentile of Alternative Maximum STEM Price outcomes).

Parkeston Units

- Table 15 presents the calculation of the Alternative Maximum STEM Price;
- Figure 21 presents the Alternative Maximum STEM Price probability density function (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

Table 14: Calculation of the Alternative Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.07
Mean Fuel Cost (heat rate adjusted)	$/MWh	432.43
Loss Factor		1.0369
Before Risk Margin	$/MWh	523.59
Risk Margin Added	$/MWh	53.16
Risk Margin Value	%	10.15
Assessed Alternative Maximum STEM Price	$/MWh	576.75

Source: Marsden Jacob analysis 2020

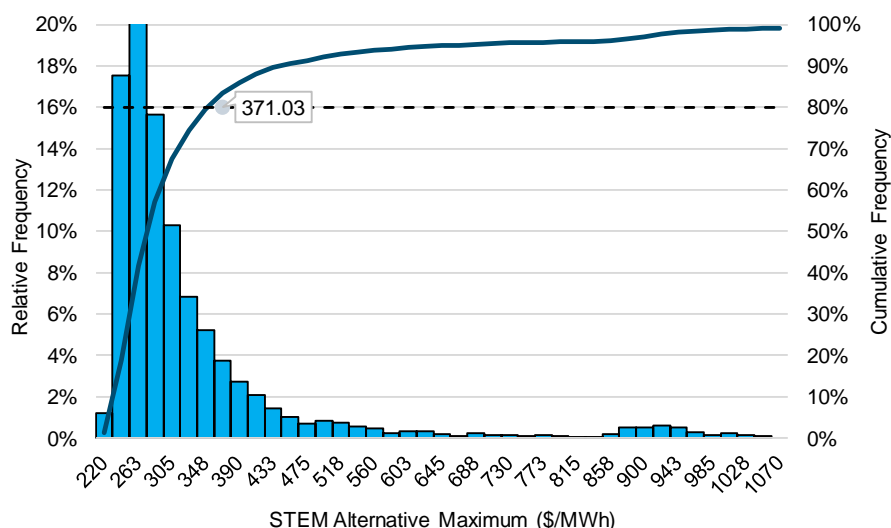## Figure 20: Alternative Maximum STEM Price probability density function – Pinjar Units

Source: Marsden Jacob analysis 2020

Table 15: Calculation of the Alternative Maximum STEM Price – Parkeston Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	50.55
Mean Heat Rate	GJ/MWh	15.31
Mean Fuel Cost (heat rate adjusted)	$/MWh	352.93
Loss Factor		1.1633
Before Risk Margin	$/MWh	346.85
Risk Margin Added	$/MWh	24.18
Risk Margin Value	%	6.97
Assessed Alternative Maximum STEM Price	$/MWh	371.03

Source: Marsden Jacob analysis 2020

Figure 21: Alternative Maximum STEM Price probability density function – Parkeston Units

Source: Marsden Jacob analysis 2020

9.2.1 Regression of Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate[25]. It is therefore necessary to separate out the cost components that depend on Fuel Cost and those which are independent of Fuel Cost.

The price components for the Alternative Maximum STEM Price that provide the 80% cumulative probability price are:
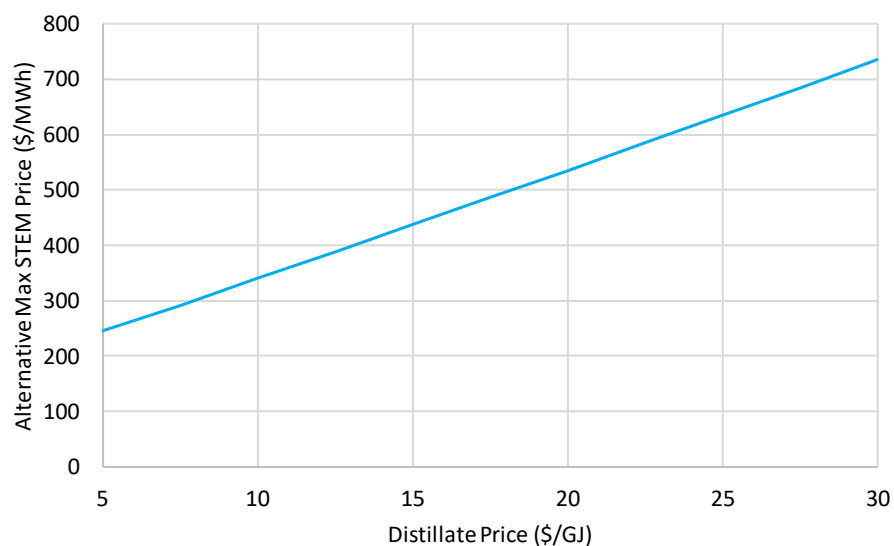
Equation 4

$$143.95_{\$/MWh} + (19.627_{GJ/MWh} \times Delivered\ Distillate\ Price_{\$/GJ})$$

The method for selection of the non-fuel and Fuel Cost factors in the above formula was based upon 10,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $5 and $30/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. The relationship using the function in Equation 4 is shown in Figure 22.

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[25] Clause 6.20.3(b) of the WEM Rules

Figure 22: Assessed Alternative Maximum STEM Price vs delivered distillate price – Pinjar Units

Source: Marsden Jacob analysis 2020

10. Changes in Energy Price Limits Compared to Previous Years

This chapter compares the results presented in the previous chapter to the results of the 2019-20 year. As the analysis shows that Pinjar was the more expensive unit in both the current and previous review this chapter focuses on the results of the Pinjar Units.

A comparison of the assessed Maximum STEM Price for 2020-21 with the previous year's price is provided in Table 16. Figure 23 presents the factors that resulted in the change.
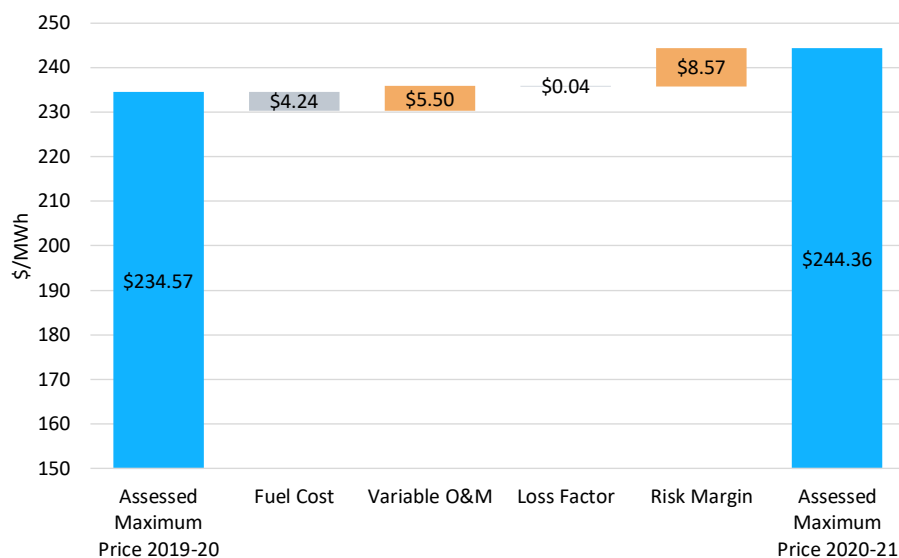
Table 16: Comparison of Maximum STEM Price to 2019-20

Component	Units	2020-21	2019-20	Change
Mean Variable O&M Cost (a)	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.19	20.62	-1.43
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	108.78	113.02	-4.24
Loss Factor		1.0369	1.0369	0.00
Before Risk Margin	$/MWh	211.45	210.24	1.21
Risk Margin Added	$/MWh	32.90	24.33	8.57
Risk Margin Value	%	15.56	11.57	3.99
Assessed Maximum STEM Price	$/MWh	244.36	234.57	9.79

Source: Marsden Jacob analysis 2019-2020

Notes: (a) Mean Fuel Cost and Mean Variable O&M Cost are not loss factor adjusted.

Figure 23: Factors causing change in the Maximum STEM Price from 2019-20 (a)

Source: Marsden Jacob analysis 2019-2020

Notes: (a) The changes in Mean Fuel Cost and Mean Variable O&M Cost have been loss factor adjusted. That is why the change is lower when compared to Table 16.

The major reasons for changes in the Maximum STEM Price since last year are explained below.

10.1.1 Variable O&M

Generation for both the Pinjar Units and Parkeston Units was higher in 2019 than 2018 and this data was not available as part of the 2019-20 review. The addition of an extra year of high generation results in a higher average generation per start increase for Pinjar from 38.5 to 49.1 MWh.

The use of a fixed annual cost for Pinjar Units in this year's review resulted in a significant change to the distribution of Variable O&M costs. The fixed costs resulted in a higher mean cost per start and a larger spread of cost per start compared to the 2019-20 review.

The combination of these two factors kept the Variable O&M costs for Pinjar similar to the 2019-20 review.

The distribution had more variance as years with units both higher and lower number of starts used the same fixed cost. Previously for Pinjar the number of starts directly impacted the Variable O&M distribution this factor results in a reduction to the variance of the distribution.

Had generation not been limited to 6 hours the Variable O&M costs would be much lower due to an average generation per dispatch of 71 MWh.

10.1.2 Fuel Costs

The continuing trend of lower gas prices resulted in a lower commodity price for gas combined with a slightly lower average Heat Rate due to the higher capacity factor resulting in a reduction in mean Fuel Costs.
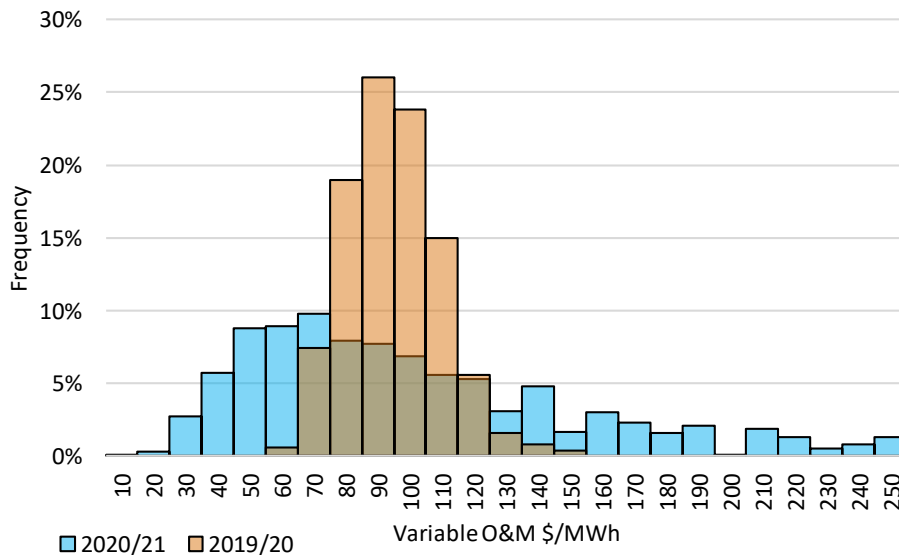
10.1.3 Risk Margin

Risk Margin value increased as a result of the inclusion of generation data for calendar year 2019.

The inclusion of 2019 with higher generation acted to lower the mean value of Variable O&M. However the low levels of generation seen in 2018 and earlier years are still included in the data sets used for distribution. As a
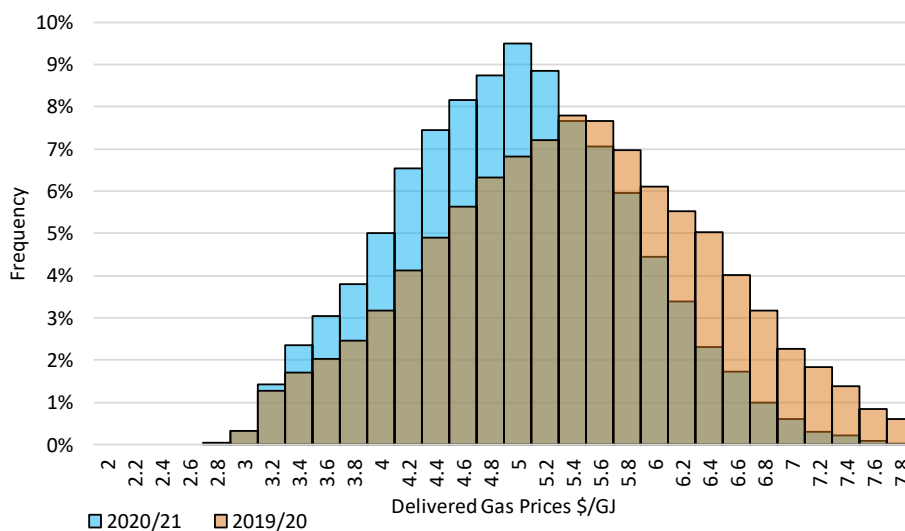
result, there are still many higher priced tail simulations. These tail simulations have more impact on the 80th percentile, and when compared to the lower mean value of Variable O&M, the Risk Margin increases.

Figure 24: Comparison of probability density function for Variable O&M Costs ($/MWh)
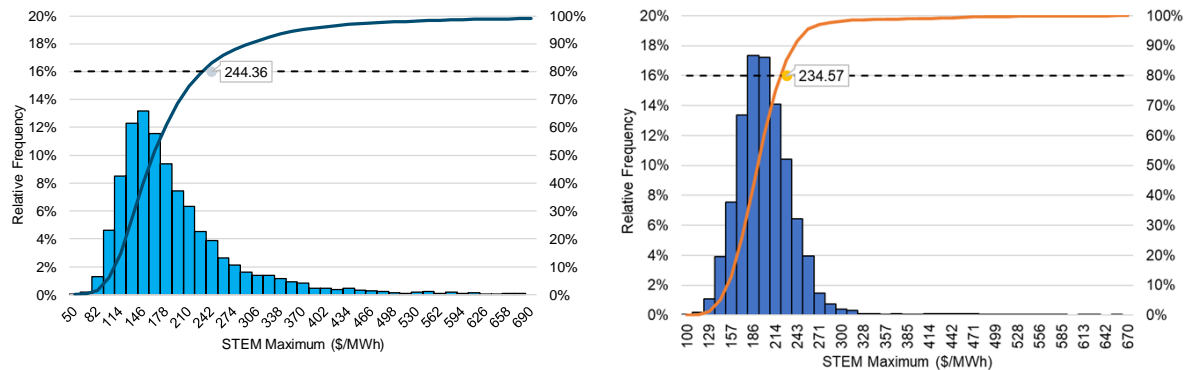

Source: Marsden Jacob analysis 2019 & 2020

Figure 25: Comparison of probability density function for Delivered Gas Costs ($/GJ)

Source: Marsden Jacob analysis 2019 & 2020

The distribution of Variable O&M Costs and gas costs has a direct influence on the probability density function for Maximum STEM Prices, and hence the 80th percentile price which determines the Risk Margin value. The probability density functions for 2019-20 and 2020-21 Maximum STEM Prices are provided in Figure 26.

Figure 26: Comparison of probability density functions for Maximum STEM Prices ($/MWh) – Pinjar Units 2020-21 (left) and 2019-20 (right)

Source: Marsden Jacob analysis 2019,2020

The Alternative Maximum STEM Price has increased slightly compared to last year. A lower Heat Rate has caused the mean Fuel Cost to decrease slightly despite only a small change in fuel costs. The Risk Margin has also increased due to the inclusion of calendar year 2019 data.

A comparison of assessed upper prices with historical outcomes in nominal dollars since 2014-15 is provided in Figure 28.

The Alternative Maximum STEM Price is slightly higher than last year, resulting mostly from a change in the Risk Margin.
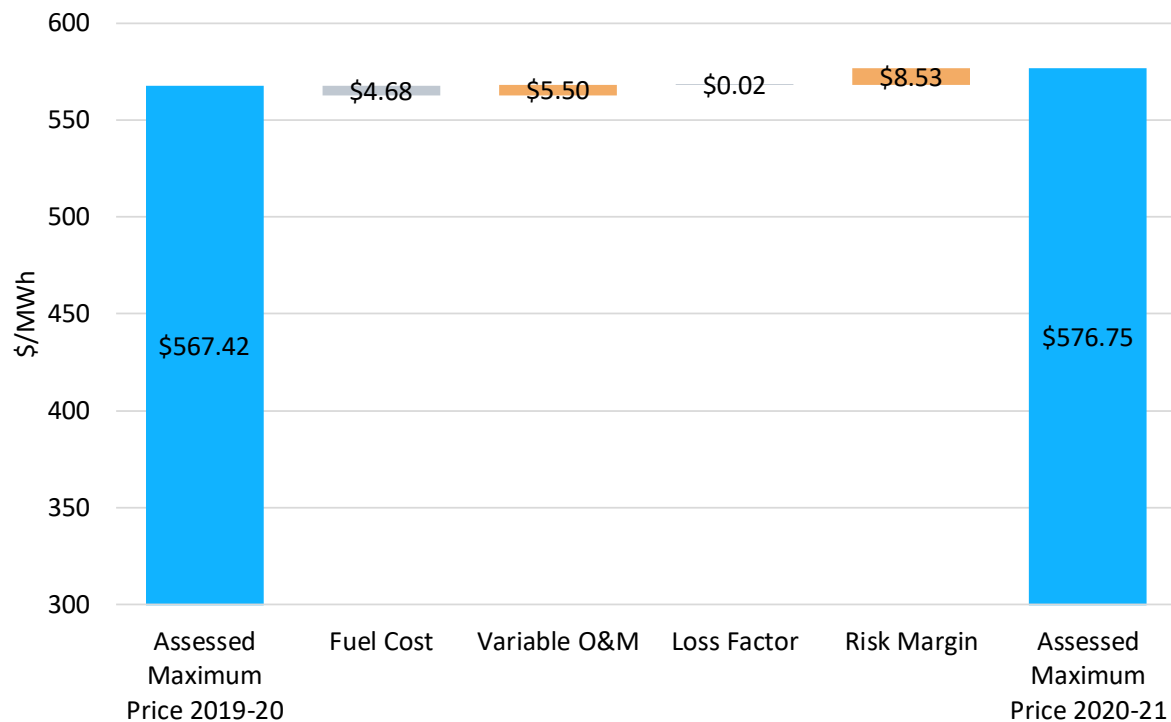
Table 17: Comparison of Alternative Maximum STEM Price to 2019-20

Component	Units	2020-21	2019-20	Change
Mean Variable O&M Cost (a)	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.07	20.62	-1.55
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	432.43	437.11	-4.68
Loss Factor		1.0369	1.0369	0.00
Before Risk Margin	$/MWh	523.59	522.79	0.80
Risk Margin Added	$/MWh	53.16	44.63	8.53
Risk Margin Value	%	10.15	8.54	1.61
Assessed Alternative Maximum STEM Price	$/MWh	576.75	567.42	9.33

Source: Marsden Jacob analysis 2019 -2020

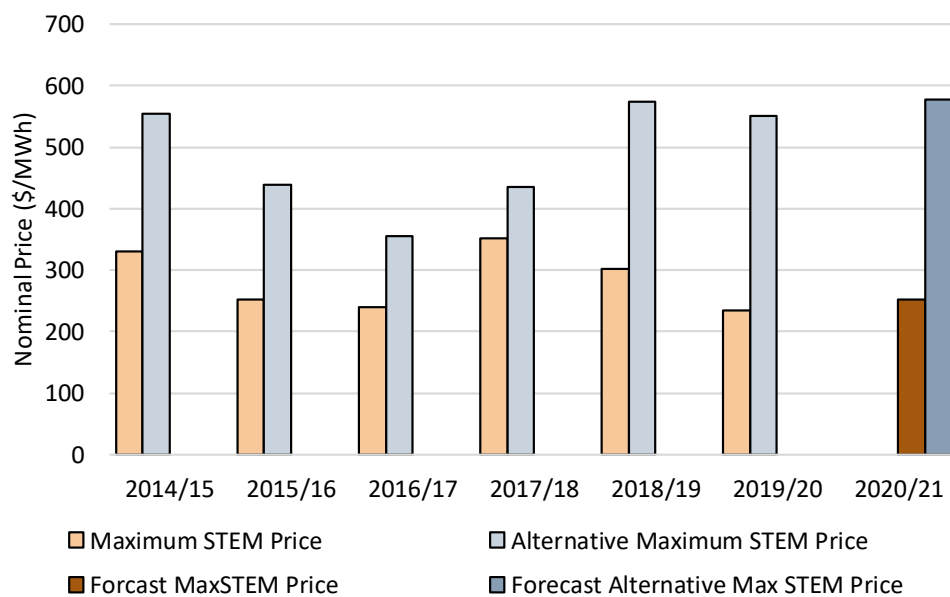*Notes: (a) Mean Fuel Cost and Mean Variable O&M Cost are not loss factor adjusted.*

Figure 27: Factors causing change in the Alternative Maximum STEM Price from 2019-20 (a)

Source: Marsden Jacob analysis 2019-2020,

Notes: (a) The changes in Mean Fuel Cost and Mean Variable O&M Cost has been loss factor adjusted. That is why the change is lower when compared to Table 17.

Figure 28: Comparison of assessed upper Energy Price Limits with historical prices

Source: Marsden Jacob analysis 2020, AEMO