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2019-20 Energy Price Limits Review – Draft Report (Public)

A Report for the Australian Energy Market Operator

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A Marsden Jacob Report

I

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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
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
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
PDF	probability density function
SRMC	short run marginal cost
STEM	Short Term Energy Market
TGP	Terminal Gate Price
VOM	variable operating and maintenance
WEM	Wholesale Electricity Market

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 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.
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.
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 $ per 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 per MWh[3].
Heat Rate	A measure of the efficiency of a generation plant that converts fuel into electricity. Usually measured in GJ per 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, MUNGARRA_GT2 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).
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 $ per MWh of generation (generated or sent out).
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 $ per MW per annum.
Parkeston Units	Collectively means the 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG.

[1] Chapter 11 of the WEM Rules
[2] Clauses 6.20.6 and 6.20.10 of the WEM Rules
[3] Chapter 11 of the WEM Rules
[4] Chapter 11 of the WEM Rules

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 $ per MWh.
Short Term Energy Market	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.
WEM Rules	The Western Australian Wholesale Electricity Market (WEM) Rules.

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

Executive Summary

The Australian Energy Market Operator (AEMO) is required under section 6.20 of the Wholesale Electricity Market Rules (WEM Rules) to review the Energy Price Limits that apply to the Wholesale Electricity Market (WEM) for the 2019-20 financial year. The Energy Price Limits represent the upper and lower price limits for offers submitted into the Short Term Energy Market (STEM) and the Balancing Market. Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the upper price limits for 2019-20.[6]

The Energy Price Limits are set with reference to the costs of running a 40 MW Open Cycle Gas Turbine (OCGT)[7]. The Maximum STEM Price applies to generation facilities that are running on non-liquid fuels (e.g. coal, gas), while the Alternative Maximum STEM Price applies to generation facilities running on liquid fuels (i.e. distillate). The candidate generation units to be used in the review of the Energy Price Limits included the Pinjar 40 MW gas turbines (6 units) and the Parkeston aero-derivative gas turbines (3 units). The candidate generation units are selected based on unit size (40 MW) and the likely running cost of the plant; the latter is a function of historical dispatch patterns and plant heat rates amongst other factors (listed below). The Mungarra gas turbines were considered candidate generation units in previous Energy Price Limit reviews but have been excluded from setting upper price limits in this review given that they are not actively participating in the energy market and are providing a Network Control Service in the North Country Region.

To derive the costs of running (referred to as *dispatch cost*) of the candidate OCGT units, Marsden Jacob has consulted with relevant Market Participants, and collated and analysed data that will impact the dispatch cost of the units. That includes the following:

- Fuel prices (i.e. gas and distillate);
- Unit heat rates (GJ per MWh);
- Variable operating and maintenance costs (or Variable O&M);
- Loss Factor.

Both fuel (i.e. fuel price multiplied by unit heat rate) and non-fuel (Variable O&M) costs are a function of the frequency of unit start-ups, average duration of each dispatch event (in hours) and loading of the generator (in MW). Using five-year historical data, forecast values for each of these variables for the Pinjar and Parkeston Units for 2019-20 have been derived.

Based on analysis by Marsden Jacob, the most expensive 40 MW OCGT units are the Pinjar units. The value of variables that influence the unit dispatch cost and ultimately the assessed Maximum STEM Price are summarised in ES Table 1. The analysis indicates that the Maximum STEM Price should be $205.99 per MWh for the 2019-20 year.

ES Table 1: Calculation of Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M	$/MWh	70.75
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost	$/MWh	112.28
Loss Factor		1.03
Before Risk Margin	$/MWh	178.01
Risk Margin Added	$/MWh	27.98
Risk Margin Value	%	15.70
Assessed Maximum STEM Price	$/MWh	205.99

Source: Marsden Jacob analysis 2019

[6] The Minimum STEM Price is fixed at -$1,000 per MWh (Chapter 11 of the WEM Rules) and is not being reviewed in this study.
[7] Clause 6.20.7of the WEM Rules

The components of the Alternative Maximum STEM Price that are derived from an assessment of the dispatch costs of the Pinjar 40 MW Units are provided in ES Table 2.

ES Table 2: Calculation of Alternative Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M	$/MWh	70.75
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost	$/MWh	434.22
Loss Factor		1.03
Before Risk Margin	$/MWh	491.98
Risk Margin Added	$/MWh	46.56
Risk Margin Value	%	9.50
Assessed Alternative Maximum STEM Price	$/MWh	538.55

Source: Marsden Jacob analysis 2019

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate, based on historical Perth Diesel Terminal Gate Prices. 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 per cent cumulative probability price are:

$81.655 per MWh + 21.44 multiplied by the Delivered Distillate Price ($ per GJ)

A comparison of the assessed Maximum STEM Price for 2019-20 with the previous year's price limit is provided in ES Table 3.

ES Table 3: Comparison of Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M	$/MWh	70.75	129.59	-58.84
Mean Heat Rate	GJ/MWh	20.62	19.22	1.4
Mean Fuel Cost	$/GJ	112.28	121.31	-9.03
Loss Factor		1.03	1.03	0.00
Before Risk Margin	$/MWh	178.01	243.07	-65.06
Risk Margin Added	$/MWh	27.98	58.93	-30.95
Risk Margin Value	%	15.7	24.2	-8.5
Assessed Maximum STEM Price	$/MWh	205.99	302	-96.01

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

The major reasons for changes in the Maximum STEM Price since last year are explained in detail in Section 4.4 and are summarised below.

1. Lower *Mean Variable O&M Cost* ($70.75 per MWh compared to $129.59 per MWh last year). The Mean Variable O&M Cost per MWh is equal to the Mean Variable O&M cost per start divided by Dispatch Event MWh (for dispatch events of 6 hours or less duration).

    a) *Mean Variable O&M Cost per MWh* – as outlined in Section 3.2, Marsden Jacob have determined that the Mean Variable O&M cost per start for the Pinjar Units is $2,724 per start for 2019-20, whereas the equivalent cost used in developing the 2018-19 Maximum STEM Price was $3,320 per start and was $4,279 per start in 2017-18. The significant reduction in the Mean Variable O&M cost per start from 2017-18 to 2018-19 was due to a change in the methodology used to calculate this variable (e.g. excluding overhaul costs incurred in the last 3 years of the plant's life). The Mean Variable O&M cost per start for 2018-19 was a modelled outcome and did not refer to the actual maintenance cycle or costs incurred in maintaining the Pinjar Units. Synergy did not provide any relevant information in the 2018-19 review. Synergy has provided confidential information pertaining to unit asset lives and O&M costs for the determination of Energy Price Limits in 2019-20. This information suggests that Mean Variable O&M costs per start for the Pinjar Units are significantly below previous (modelled) estimates. This has been factored into the determination of maintenance costs.

    b) Marsden Jacob calculated *Dispatch Event MWh* for events of 6 hours or less duration. This included data for all Pinjar Units over the period 2013-14 to 2018-19 (ending February 2019). It was found that across all Pinjar Units, the average generation output was 38.5 MWh per event. The equivalent amount calculated for the 2018-19 review was 26 MWh. Previous reviews have typically found that Dispatch Event MWh (6 hours or less) was around 26 MWh.

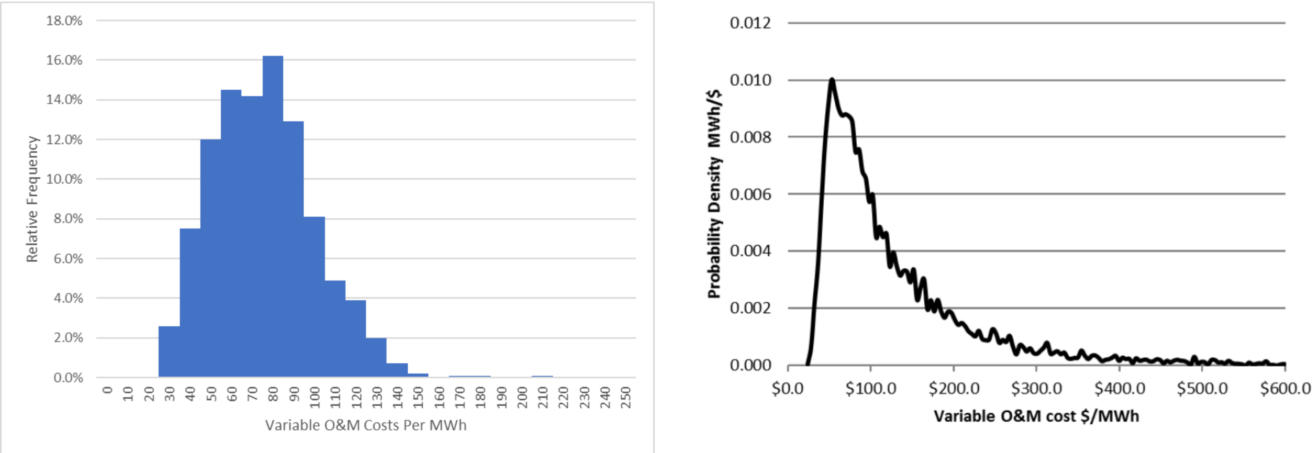
    c) Therefore, the *Mean Variable O&M Cost* for 2019-20 is calculated to be $70.75 per MWh (i.e. $2,724 per start / 38.5 MWh per start). The Variable O&M Cost for 2018-19 was calculated to be $129.59 per MWh (i.e. $3,320 / 26 MWh per start).

    Lower *Mean Fuel Cost* ($9.03 per GJ lower in 2019-20) resulting from lower gas commodity prices. The delivered cost of (spot) gas is forecast to be $5.445 per GJ for 2019-20. The mean delivered spot gas cost was forecast to be $6.31 per GJ in 2018-19. The lower delivered spot price for gas has resulted due to the continued over supply of gas in the domestic market, which resulted in average spot gas price forecasts reducing to $3.41 per GJ in 2019-20, compared to average spot prices of $4.00 per GJ for 2018-19. The underlying spot gas price forecast used in the 2018-19 review was $4.02 per GJ.

2. Reduced *Risk Margin Value* due to a smaller variance in the distribution of Maximum STEM Prices, which is mainly a function of the reduced variance in Variable O&M Costs and delivered (spot) gas prices.

    As outlined in Point (1) above, modelled mean Variable O&M costs ($ per MWh) have fallen. In addition, the modelling of Variable O&M Costs in 2019-20 has a significantly narrower probability distribution function when compared to the modelling undertaken to support Energy Price Limits in 2018-19. The probability density function (PDF) for Variable O&M for this year is compared with the PDF for last year in ES Figure 1.

ES Figure 1: Comparison of PDF for Variable O&M Costs ($/MWh) for Pinjar Units – Left (2019-20) and Right (2018-19)



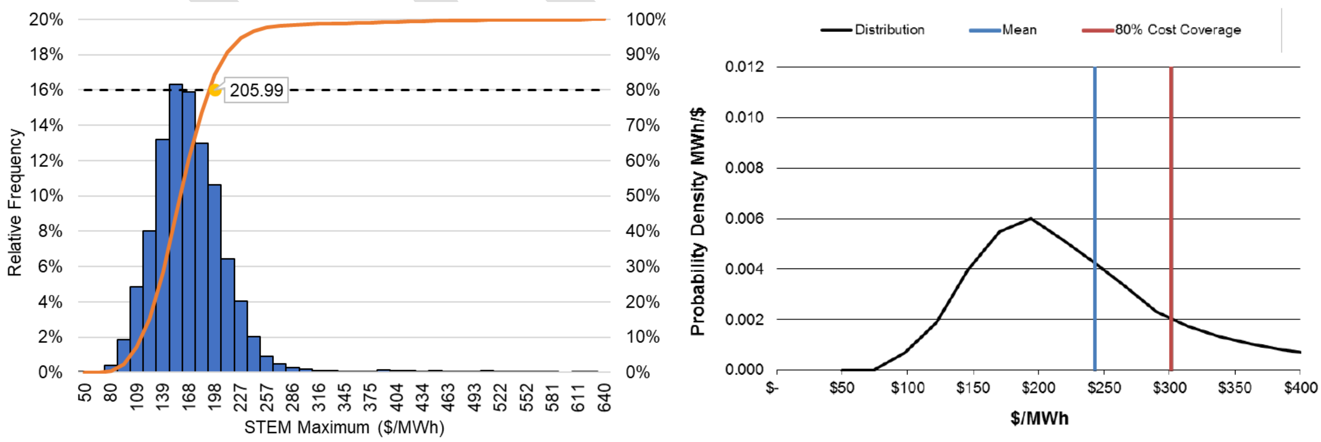
Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

This highlights the considerable range of Variable O&M Costs that could occur under the modelling undertaken in the 2018-19 review. Variable O&M costs could be as high as $600 per MWh in last year's modelling, whereas modelling for setting the 2019-20 Energy Price Limits indicates that the maximum Variable O&M costs are only likely to be around $208 per MWh for the Pinjar Units. As a result of the significantly higher range of values modelled in previous reviews, mean Variable O&M costs ($129.59 per MWh) are substantially above the median cost ($96 per MWh), and the standard deviation of costs is $99.15 per MWh. The estimated standard deviation of Variable O&M costs calculated for the 2019-20 review is $24 per MWh, with a mean of $71 per MWh. The 80th percentile of Variable O&M costs is around $90 per MWh.

The distribution of delivered gas prices for 2019-20 also has a significant influence on the distribution of Maximum STEM Prices. This is discussed further in Section 4.4.

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 PDFs for 2018-19 and 2019-20 Maximum STEM Prices are provided in ES Figure 2.

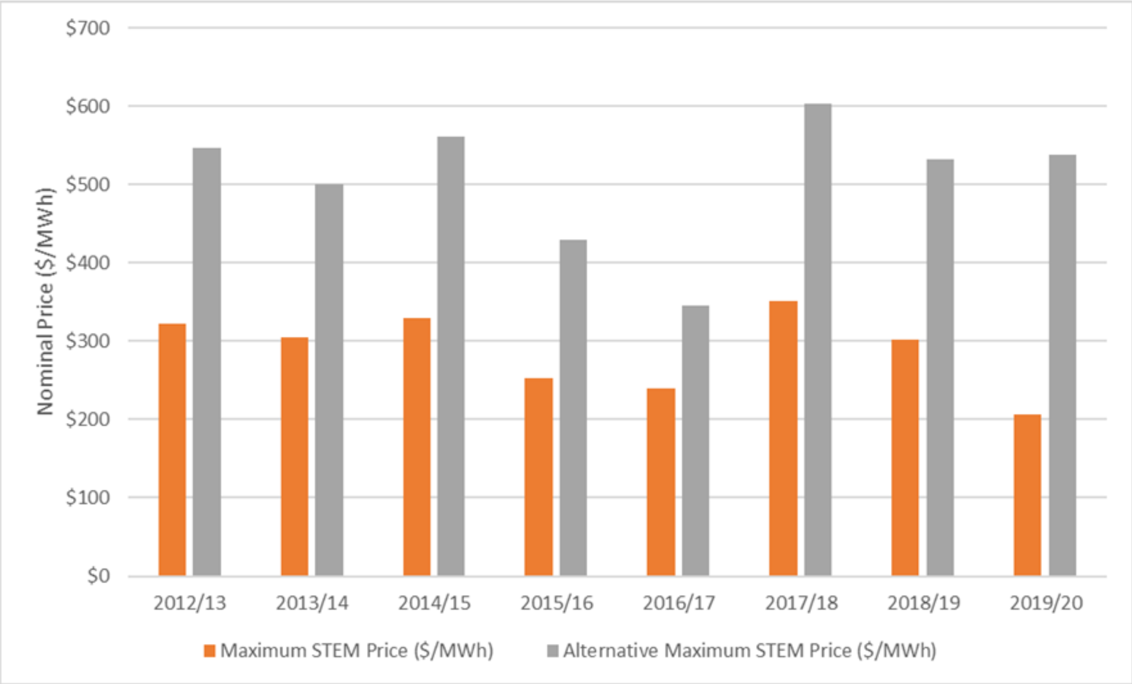
ES Figure 2: Comparison of PDF for Maximum STEM Prices ($/MWh) for Pinjar Units – Left (2019-20) and Right (2018-19)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Provided in ES Figure 3 is a comparison of the assessed upper Energy Price Limits with previous upper Energy Price Limits. What this shows is that the assessed Maximum STEM Price is the lowest price (in nominal dollars) since 2012-13. This is broadly consistent with lower commodity gas prices that are projected for 2019-20. However, the reduction in Variable O&M and Risk Margin in 2019-20 are also significant factors (see Section 4.4). On the other hand, the Alternative Maximum STEM Price has increased from last year as a result of higher distillate prices that have increased in response to projected increases in crude oil prices in 2019 and 2020.

ES Figure 3: Comparison of assessed and historical upper Energy Price Limits



Source: Marsden Jacob analysis 2019

1. Background and Scope of Work

1.1 Purpose of this Report

AEMO is required under section 6.20 of the Wholesale Electricity Market Rules (WEM Rules) to review the Energy Price Limits for the 2019-20 financial year. The Energy Price Limits 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[8] are:

- 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 $1,000 per MWh).

Only a review of the Maximum and Alternative Maximum STEM price is required for the 2019-20 review. Revised values must then be submitted to the Economic Regulation Authority (ERA) for approval[9].

Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the Energy Price Limits for 2019-20.

1.2 Scope of Work

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

a) assess the methodology used in the 2018-19 review and clearly articulate and justify any changes to the methodology (ensuring that the methodology is consistent with the requirements in clause 6.20.7 of the WEM Rules), including consideration of:

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

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

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

         – 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

         – 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;

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

      D. 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

      E. 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;

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

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:

   i. gas price distributions; and

   ii. 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 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: Determination of Key Parameters;
- Chapter 4: Modelling Results;
- Appendix One: Determination of Key Parameters for the Parkeston Aero Derivative Units

2. Methodology Review

This chapter discusses the methodology as it was applied in this review. Previous reports and stakeholder feedback on the Energy Price Limits have been incorporated into the methodology for 2019-20.

2.1 Determination of Maximum Prices in the WEM

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 these services so that they are encouraged to provide their capacity during high price periods in the WEM.

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

The Maximum and Alternative Maximum STEM Prices are set based on the average variable cost of the highest cost generating facility in the South West Interconnected System (SWIS) using the following formula[10]:

$$\text{Dispatch Cost} = (1 + risk\ margin) \times (variable\ O\&M + (heat\ rate \times fuel\ cost)) \,/\, loss\ factor \quad (1)$$

where:

- $risk\ margin$ 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;
- $variable\ O\&M$ is the mean variable operating and maintenance cost of a 40 MW open cycle gas turbine generating station, expressed in $ per MWh, and includes, but is not limited to, start-up costs;
- $heat\ rate$ is the mean heat rate at minimum capacity of a 40 MW open cycle gas turbine generating station, expressed in GJ per MWh;
- $fuel\ cost$ is the mean unit fixed and variable fuel cost of a 40 MW open cycle gas turbine generating station, expressed in $ per GJ; and
- $loss\ factor$ 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 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 then 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.

The Alternative Maximum STEM price is based on the following: the 80th percentile cost of formula (1) (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 component that is proportional to the net ex

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

terminal distillate price. Each month the Alternative Maximum STEM price is determined by substituting the current net ex distillate price into the regression equation (2).

$$\text{Alternative Maximum STEM Price} = \text{constant} + \alpha \times \text{Distillate Price} \quad (2)$$

2.2 Selection of the Candidate Peaking Generators

The above input variables will vary depending on which 40 MW generation plant is used to establish the dispatch cost used to set Energy Price Limits. In previous studies, Energy Price Limits have been based on the Pinjar 40 MW gas turbines (6 units). Other candidate generators include the Parkeston aero-derivative gas turbines (3 units) located in the Goldfields Region, and the Mungarra gas turbines (3 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 a total of 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, however these units are not being considered as candidate peaking generators). 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"*[11]. 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 in to 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. AEMO can only dispatch the facility under instruction from Western Power. A Market Participant providing an NCS is paid by Western Power in accordance with the contract.

In conclusion, since the Mungarra Units will not be dispatched in the WEM except under the terms of the NCS 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. The facilities will be compensated under the terms of the NCS by Western Power.

Table 1 shows the capacity and the technology of the candidate units for setting Energy Price Limits in 2019-20. The WEM Rules stipulate that the candidate units must be 40 MW OCGT units. 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) which implies that they will have higher heat rates when compared to other gas turbines connected to the SWIS.

Table 1: Candidate OCGT units for setting 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 1	37	Aero-derivative

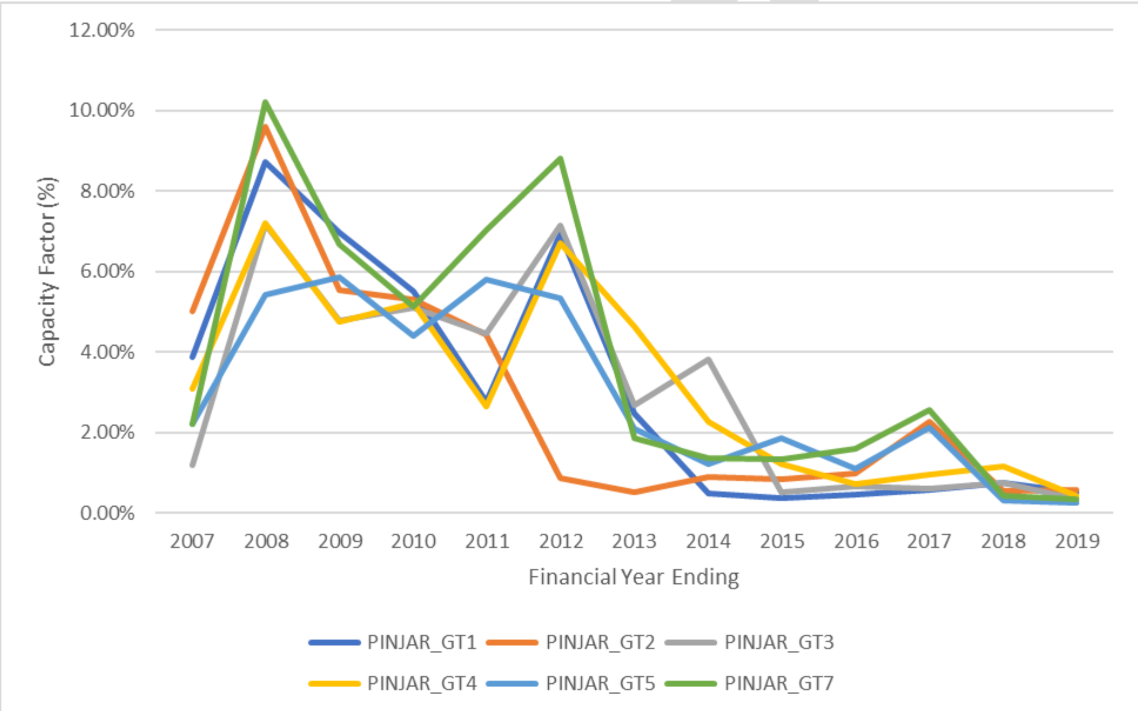
[11] Clause 5.1.1 of the WEM Rules

PRK_AG unit 2	37	Aero-derivative
PRK_AG unit 3	37	Aero-derivative

Source: AEMO Facilities Data, Marsden Jacob analysis 2019

The Pinjar Units (GT 1 to 5 and 7) are owned and operated by Synergy and are used to provide peaking power in the SWIS. The units were fully operational by October 1990 and have typically had capacity factors of around 3 per cent on average, although the capacity factor can vary significantly between units and across years. The capacity factor of the Pinjar Units has declined overtime 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 around 1.2 per cent in the last three years. This increases 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.

Figure 1: Capacity factor of Pinjar Units

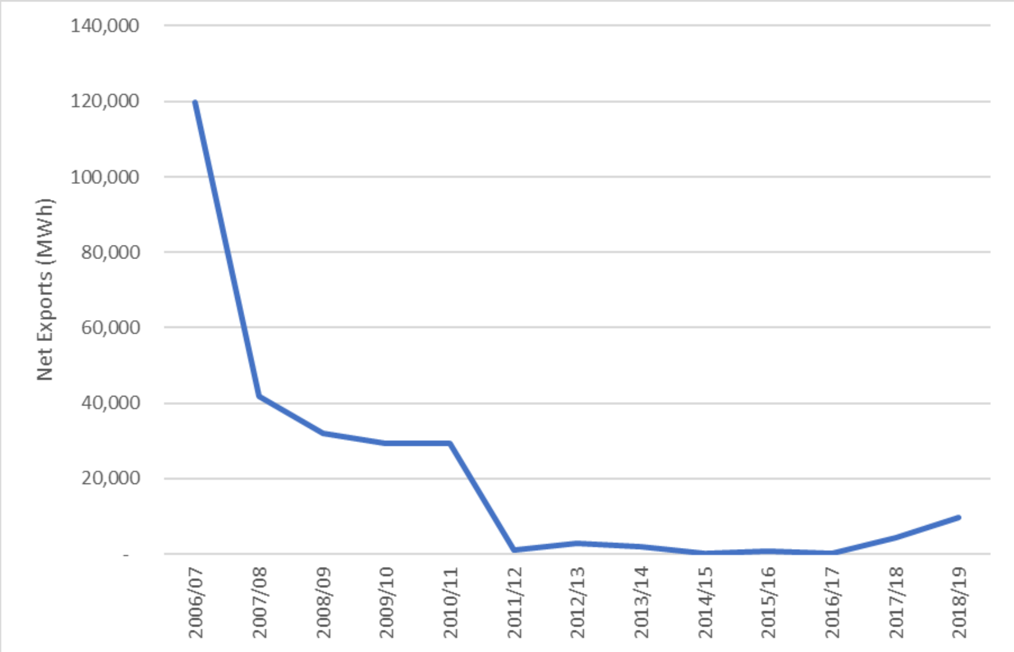


Notes: 2007 financial year ending data only includes data commencing September 2006, while 2019 financial year ending data only includes data up to and including February 2019.

Source: AEMO Facility Scada Data, Marsden Jacob analysis 2019

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 load is usually met by a single generation unit (GT1 in 2018) and imports from the SWIS. GT2 and GT2 provide backup for GT1 and participate in the Balancing Market (i.e. net exports). 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 in Table 2.

Table 2: Operating data for candidate OCGT units in the SWIS 2018

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
No. of Starts	185	38	43	27	35	21	41
Hours Operating	645.5	137	203	107.5	120.5	100.5	109.5
Average Generation Per Trading Interval (MWh)	9.91	5.51	4.33	6.31	5.73	5.59	5.55
Average Output (MW)	19.82	11.02	8.65	12.63	11.47	11.18	11.11
Annual Generation (MWh)	12,795	1,510	1,756	1,358	1,382	1,124	1,216
Capacity Factor (%)	2.1	0.4	0.5	0.4	0.4	0.3	0.4
Hours Per Start	3.49	3.61	4.72	3.98	3.44	4.79	2.67

Source: Marsden Jacob analysis 2019

What this shows is that the Pinjar Units had between 21 and 43 starts in 2018 and did not operate frequently (100 to 200 hours in a year). This suggests that estimating start-up costs correctly will be critical in determining Energy Price Limits, since the units do not operate for long periods (2.67 to 4.72 hours per start on average).

It should be noted that the operation of the Pinjar Units is appreciably down compared to 2017. Milder summer temperatures (i.e. cooling degree days) has reduced air conditioning use and lowered average demand in the SWIS compared to previous years. On average, generation from the Pinjar Units in 2018 is 53 per cent lower compared to the previous 12-month period.

On the other hand, exports from the Parkeston Units has increased appreciably in 2018 (12,795 MWh) compared to 2017 (482 MWh).

Table 3: Captured Balancing and STEM Prices ($/MWh, nominal) 2018

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
Average STEM Price When Running ($/MWh)	77.4	66.1	62.3	68.2	70.8	68.3	68.9
Average BP Price When Running ($/MWh)	80.1	85.8	66.4	66.0	67.1	68.8	88.2
Max STEM Price Captured ($/MWh)	167.8	139.7	142.3	142.3	176.7	176.7	137.3
Max BP Price Captured ($/MWh)	302.0	269.4	269.4	151.3	201.0	269.3	269.4

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

Source: Marsden Jacob analysis 2019

Table 3 highlights that only the Parkeston Units were able to capture the Maximum STEM Price in 2018. It should be noted that the Maximum STEM Price only occurred three times in the Balancing Market in 2018 and not at all in the STEM ($302 per MWh). The Maximum STEM Price has not previously cleared in the STEM, while the Maximum STEM Price cleared in the Balancing Market on 26 trading intervals in 2016-17 but did not clear in 2017-18 or 2015-16. Table 4 illustrates the volatility of the occurrence of Maximum Prices in the Balancing Market.

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
Occurrence of Maximum STEM Price	23	5	22	0	26	0

Source: AEMO Balancing Summary Data, Marsden Jacob analysis 2019

It is likely that the energy market will be subject to increasingly 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 photovoltaic and wind facilities), prices could go below zero for longer periods, while prices may be higher when scheduled generation is required to ramp up rapidly to meet the load when solar generation levels fall in the evening period (in both winter and summer).

2.3 Determining the Risk Margin

The Risk Margin is intended to allow for the uncertainty in assessing the short run marginal cost of a candidate generation plant[12], 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.

Risk Margin = Derived Energy Price Limit / Dispatch Cost - 1 (3)

Where the Dispatch Cost ($ per MWh) is a function of the four input variables, i.e.

Dispatch Cost = (Variable O&M + (Heat Rate x Fuel Cost)) / Loss Factor) (4)

The methodology for determining the values for input variables are discussed below.

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

2.3.1 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.

It is problematic how start-up costs (i.e. accelerated maintenance) will be factored 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 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 often 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. This includes the Electric Power Research Institute (EPRI) study into power generation costs in Australia[13], as well as 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.

Marsden Jacob estimates of Variable O&M for both the Pinjar and Parkeston Units, and the triggers for this expenditure, is provided in Section 3.2.

2.3.2 Heat Rate

Heat rate curves for the benchmark OCGT units have been sourced from Synergy (Pinjar) and Goldfields Power Pty Ltd (Parkeston) as owners of the respective units. The heat rate curves show how unit heat rates vary with generation output (no temperature adjustments since there is less than a one per cent impact on the heat rate between high and low temperatures).

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.

A more detailed discussion on the Heat Rates is provided in Section 3.4.

2.3.3 Fuel Costs

Estimates of dispatch costs are highly dependent upon fuel price assumptions. As most OCGT plant operate at a thermal efficacy less than 32 per cent, a $1 per GJ change in fuel price results in a $11.25 per MWh change in dispatch costs in a trading interval.

The Maximum STEM Price is calculated based on the dispatch costs of a 40 MW unit using natural gas, while the Alternative Maximum STEM Price is calculated based on the dispatch costs of a unit using distillate[14]. In this section, the methodology for determining delivered gas and distillate prices is outlined.

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

[14] Chapter 11 of the WEM Rules

Commodity Gas 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 market participants want to vary their offtake volumes above contracted maximum levels or below ToP levels. While there is no centralised spot gas market in WA, 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.

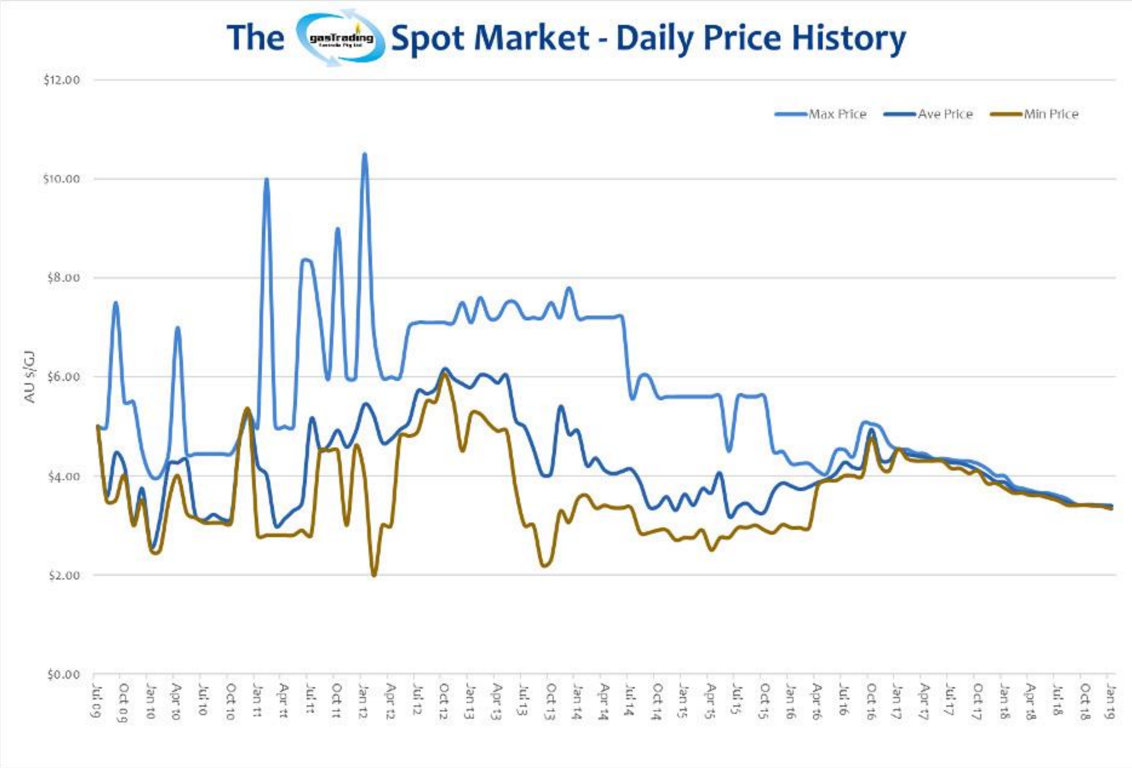
It should also be pointed out that most gas is traded informally between the major gas buyers and sellers in Western Australia. There is a high concentration of both major buyers and sellers which implies that each party can simply enter into bilateral spot transactions on a daily, weekly or monthly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

Data from gasTrading’s website is publicly available. For the past three years, typical volumes traded range from 5 to 25 TJ per day (0.5 to 2.0 per cent of WA domestic gas volumes) and prices paid range from $2.00 to $10.40 per GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.

Past consultants used the historical price data from gasTrading to develop a spot gas price that could be used to derive a Maximum STEM Price in previous studies. Daily spot gas prices are shown in Figure 3 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 3: Daily spot gas prices in Western Australia ($/GJ, nominal)



Source: gasTrading website[15]

The forecasts of gas commodity prices using the gasTrading data is provided in Section 3.3.1.

Gas Transport Cost

Gas transportation is usually incorporated into the fuel cost ($ per GJ) of supply offers from generators. However, gas haulage fees can usually be classified into two components: a reservation component charged on capacity reserved and a commodity component charged on volumes shipped. In the case of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the capacity reservation charge represents 80 per cent of the total haulage fee.

Given that most parties enter into long term haulage agreements with pipeline operators, it can be argued that the capacity component of the haulage charge is a fixed cost for most proponents and hence the commodity component of the charge is only relevant to determining the fuel cost of an OCGT plant. This implies that a gas transport charge of only $0.32 per GJ, compared to total gas transport charge of $1.605 per GJ (assuming 100 per cent load factor) on the DBNGP for 2018-19.

However, given that an OCGT operates at low capacity factors, it may choose to only utilise gas when transport and commodity gas is available and distillate at other times. If it purchases gas in this way, then the full transport charge (both the reservation charge and commodity charge) are relevant in the determination of Energy Price Limits in the WEM.

The DBNGP offers capacity on a spot basis[16] to shippers via a bidding process. No data is available on price outcomes but typically the clearing price is set at a premium (15 per cent) above the T1 tariff rate. The DBNGP trading site shows that there is spare capacity on the pipeline (approximately 60 TJ per day on average in 2017-18).[17]

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[15] http://www.gastrading.com.au/spot-market/historical-prices-and-volume, downloaded 24 February 2019.
[16] Details can be found in DBNGP P1 Standard Shipping Contract (March 2015), available at http://www.dbp.net.au/wp-content/uploads/2015/03/20150325-Standard-Shipper-Contract-P1.pdf.
[17] https://www.dbp.net.au/wp-content/uploads/2018/07/Spot-Capacity-Market-Rules.pdf

In this case, it can be argued that for a merchant OCGT plant (single unit), the relevant gas transport charge would include the full haulage charge ($1.395 per GJ) on the DBNGP plus 15 per cent. This implies a unit gas transmission tariff of $1.605 per GJ in 2018-19. Allowing for some inflation of costs on 1 January 2020, the estimated unit tariff for 2019-20 for the Pinjar Units is $1.624 per GJ (assuming they operate at 100 per cent capacity factor). This price establishes a benchmark rate for determining gas transport to Pinjar but is increased to reflect the fact that the plant will not be operating at a 100 per cent capacity factor. This adjustment is outline in Section 3.3.2.

It is understood that the Goldfields Gas Pipeline (GGP) does not systematically offer capacity on a spot basis. In previous studies, it has been assumed that when excess capacity is available, then the GGP would offer transport on a spot basis (premium to Covered Tariff published rates) to a generator which would imply that all charges (i.e. tolling and reservation) are relevant to the determination of Energy Price Limits. In addition, the published rates have been increased by 10 per cent to reflect the premium value of transport on the GGP and have also added in part haul costs on the DBNGP for shipping gas from gas production facilities to the inlet point on the GGP (estimated to be $0.1624 per GJ). The estimated gas transmission charge for the Parkeston Units is estimated to be $1.5051 per GJ. For this study, it is assumed that an OCGT plant could negotiate spot commodity and transport on the GGP, which implies that the $1.5051 per GJ gas transport charge will be applied in the determination of delivered gas prices for the Parkeston Units (assuming a 100 per cent capacity factor). Further adjustments to this benchmark price are made given that the plant does not run at a 100 per cent capacity actor and is outlined in Section 3.3.2.

Distillate Prices

The Alternative Maximum STEM Price is based on distillate prices (i.e. diesel)[18]. 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[19]. This reduces the level of uncertainty for establishing Alternative Maximum STEM Prices.

In theory, the Maximum STEM Price could go above the Alternative Maximum STEM Price if the delivered gas price went above the distillate price for an OCGT. This situation is highly unlikely in practice, which implies that the Alternative Maximum STEM Price acts as price ceiling for the Maximum STEM Price. This truncation of the distribution of prices for the Maximum STEM Price has been considered in the determination of Energy Price Limits.

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.

2.4 Statistical Modelling Methodology

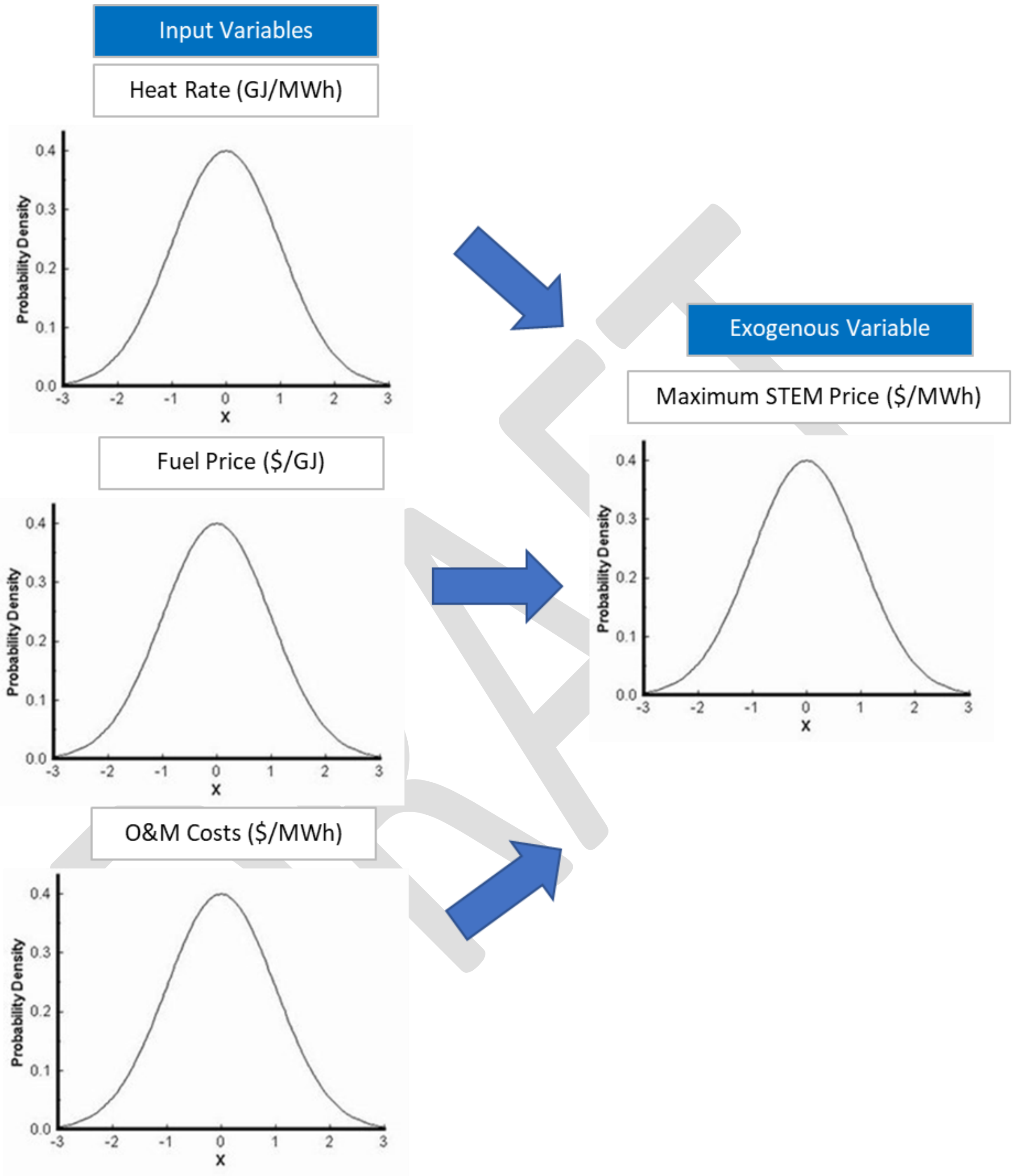
As outlined earlier, there is considerable uncertainty regarding many of the variables that make up the formula for the Energy Price Limits. This includes the heat rate of the benchmark unit, Variable O&M, and fuel cost (i.e. gas and distillate prices). Using statistical methods, Marsden Jacob have generated probability distributions for each of the key input variables that are uncertain (see Chapter 3). Figure 4 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

[18] Chapter 11 of the WEM Rules
[19] Clause 6.20.3(b) of the WEM Rules

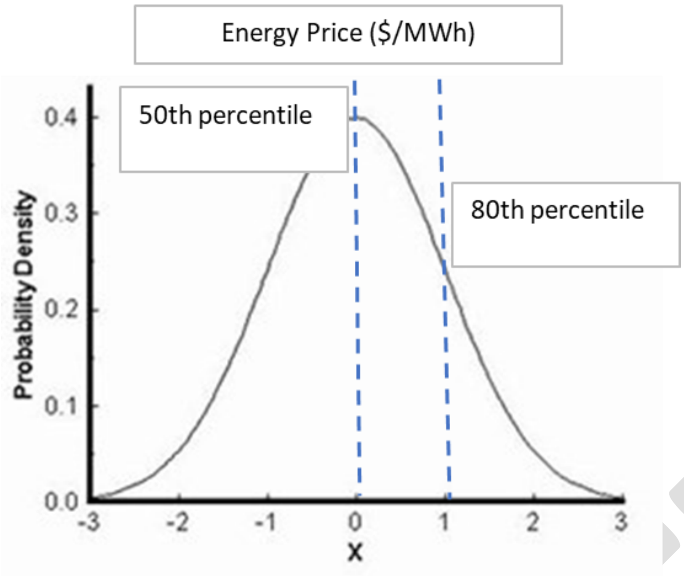
has undertaken 10,000 iterations of the model to generate the probability distribution of possible Maximum STEM Price outcomes.

Figure 4: Monte Carlo simulations used to generate Maximum STEM Price probability density function



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 per cent 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 5).

Figure 5: Decision rule for determining Maximum STEM Price (80th percentile) and Risk Margin



2.5 Addressing Feedback from Previous Reviews

The ERA and Perth Energy provided feedback to AEMO on the approach taken to estimate Variable O&M costs in the previous 2017-18 review and the ERA has raised some of these issues in the 2018-19 Decision on the Energy Price Limits. The issues raised are discussed below.

2.5.1 Maintenance Cycle Length

The 2018-19 review considered that the remaining life of the Pinjar Units was 44 years (was 29 years in the 2017-18 review). Consequently, a maintenance program would need to be put in place to ensure that the plant can operate for another 44 years.

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 around 2030, at which time they will be 40 years old and at the end of their useful lives. This implies that the maintenance program will only need to ensure that the smaller Pinjar Units remain operational until 2030. 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.

If the maintenance cycle requires a major overhaul three years prior to the retirement of the unit, this cost will not be included in the overall O&M costs as suggested by the ERA.

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

2.5.2 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. The 2018-19 review calculated the cost per start as $3,320 (2018-19) down from $4,279 in 2017-18. 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, below 60 per cent of 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. The cost for a start during which the machine is only run at low load would then be only $2,140. This is a significant difference in start-up costs and has a major impact on Energy Price Limits in the WEM.

For this study, Marsden Jacob have investigated this and adjusted the estimated number of starts with low loads only contributing 0.5 for a normal start. The estimated starts for both the Pinjar and Parkeston Units are provided in Section 3.2.3 and in Appendix One respectively.

2.5.3 Discount Rate

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

1. Use a risk-adjusted discount rate based on the perceived riskiness of the future expenditures;
2. A Monte Carlo simulation can be run by drawing samples from distributions assigned to future maintenance expenditures. The characteristics of the assigned distribution is determined by the variability of future maintenance expenditures. In the next step, the present value of drawn cash flows is 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.

However, for this study Method 1 has been utilised since the actual estimates of maintenance expenditures are based on data provided by both Synergy (Pinjar) and Goldfields Power Pty Ltd (Parkeston) and there is a high degree of confidence in the determination of maintenance costs per start (see Section 3.2). Future maintenance expenditures have been discounted using a real pre-tax WACC of 6.3 per cent, which is based on estimates provided by IPART in regulatory price determinations (February 2019).[20]

2.5.4 Other Issues

Other issues that have been addressed in this review of the methodology for setting Energy Price Limits include the following:

- 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 (section 4.7 of the ERA's 2018 Energy Price Limits Decision); and
- 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 (section 4.8 of the ERA's 2018 Energy Price Limits Decision).

[20] Sourced from the Independent Pricing and Regulatory Tribunal, "Spreadsheet-WACC-model-February-2019.xls".

3. Determination of Key Parameters

3.1 Introduction

This chapter summarises the derivation of the key input values for setting the 2019-20 Energy Price Limits using their probability distributions and mean values.

3.2 O&M Costs

To calculate O&M costs, it has been assumed that the 40 MW Pinjar and Parkeston Units have 40 year lives. This implies that O&M costs were calculated on the basis that the 40 MW Pinjar Units are retired by 31 December 2030 and that the Parkeston Units are retired by 31 December 2036.

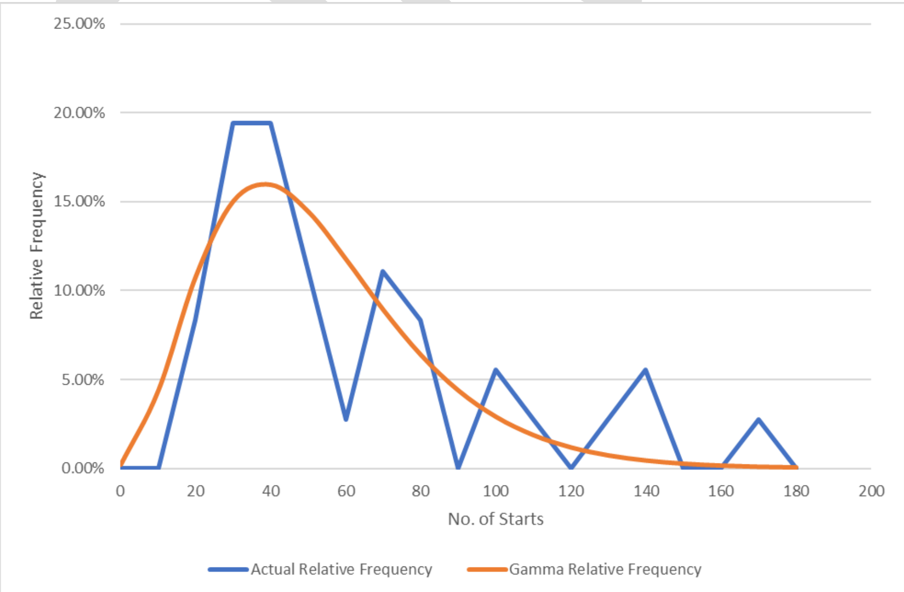
O&M costs for the units have been derived using the following six steps.

Firstly, determine a point estimate of maintenance costs per start based on confidential data provided by both Synergy and Goldfields Power Pty Ltd. The estimated costs per start are confidential and not provided in this public report however the costs range from $2,500 to $3,300 per start. This data is used to help verify the mean calculations of Variable O&M costs per start that have been developed by Marsden Jacob using the methodology outlined in this section.

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.

Secondly, create a distribution of start costs ($ per start) given that the number of starts can vary which will change the overhaul maintenance cycle and hence the Variable O&M costs per start. This is estimated for the Pinjar Units and shown in Figure 6 based on the dispatch profile of all six units over the period 2013-14 to 2018-19.[21] A probability density function was developed for the number of starts by fitting a gamma distribution to the historical distribution of starts per year.

Figure 6: Distribution of the number of starts – Pinjar Units



Source: Marsden Jacob analysis 2019

[21] 2018-19 only include dispatch information ending February 2019.

Thirdly, determine the relationship between the number of starts, which is the driver for maintenance overhaul of the Pinjar Units, and overhaul costs. The benchmark overhaul costs and unit start costs are shown in Table 5 for Pinjar only. 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). The results are shown for 58 starts per annum.

Table 5: Overhaul costs and levelised cost per start for Pinjar Units – 10 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	$1,268,704	1	$1,268,704	
B	1200	$3,353,841	1	$3,353,841	
A	1800	$1,268,704	1	$1,268,704	
C	2400	$4,843,906	1	$4,843,906	
Total Cost		$10,735,154		$10,735,154	$1,482,923
Cost Per Start (a)		$4,472.98	Levelised Cost Per Start (b)		$3,522.04
Unscheduled Maintenance Cost Contingency		20%	Unscheduled Maintenance Cost Contingency		10%
Starts / Year		58.0	NPV of Starts		421
Cost Per Start (including Contingency)		$5,368	Cost Per Start (including Contingency)		$3,874

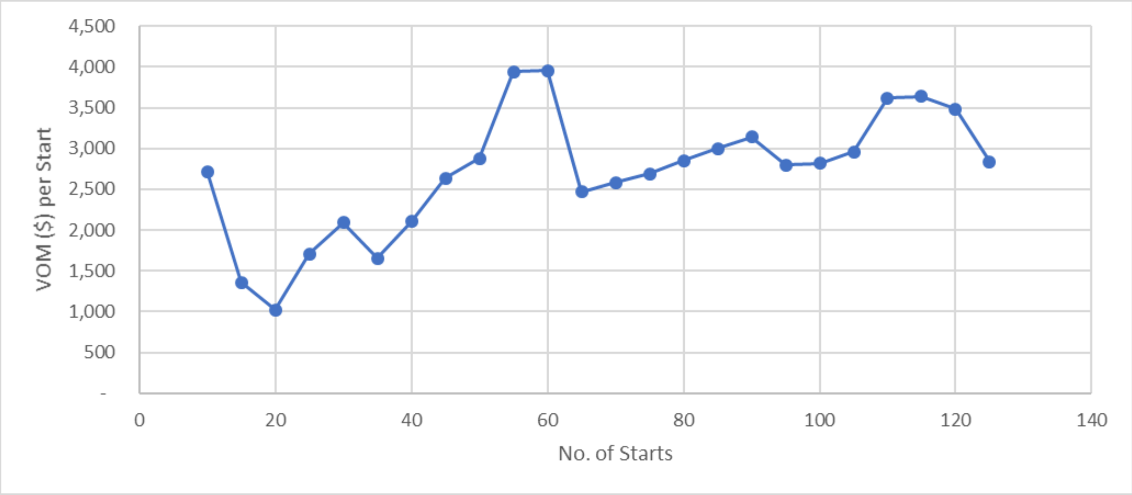
Notes: (a) Total Cost divided by 2400 starts (consistent with previous reviews)
(b) NPV of Overhaul Costs divided by NPV of Starts

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Using these costs, a relationship between start costs (Variable O&M in $ per start) and the number of starts has been created. The start costs are shown in Figure 7 and are calculated by dividing the net present value (NPV) of overhaul costs by the net present value of future starts (based on a 10-year plant life). The net present value is determined using a weighted average cost of capital (WACC) of 6.3 per cent (real pre-tax).[22] The levelised costs per start are then inflated to allow for unexpected maintenance (10 per cent). This is lower than the 20 per cent margin used in previous studies.

[22] Sourced from the Independent Pricing and Regulatory Tribunal, "Spreadsheet-WACC-model-February-2019.xls".

Figure 7: Relationship between Variable O&M costs per start and number of starts – Pinjar Units



Source: Marsden Jacob analysis 2019

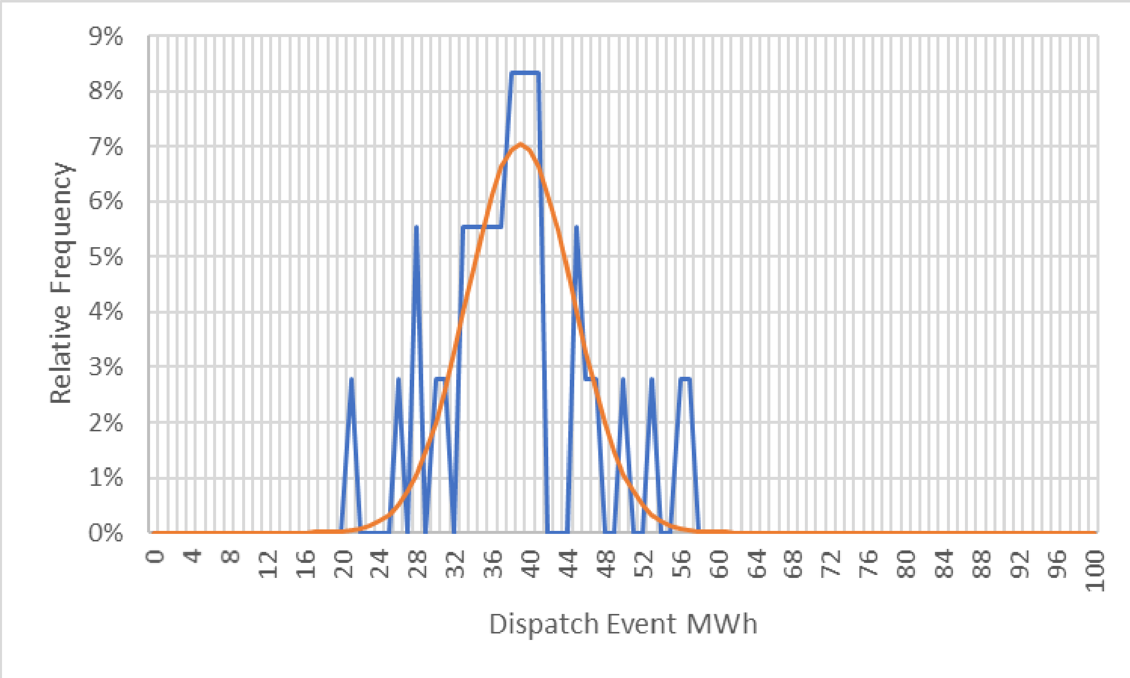
Fourthly, determine the distribution of dispatch event MWh (generation) equal to or less than 6 hours. In previous reviews of Energy Price Limits, it was argued that the Maximum STEM Price needs to cover short dispatch periods (less than 6 hours) with high prices, rather than considering longer dispatch intervals with lower prices.

The methodology employed in this review follows the previous methodology for determining Variable O&M costs on the basis that a change in the methodology will result in significant variations in future Maximum STEM Prices (up to $80 per MWh reduction in prices in one year if dispatch output is based on all dispatch events). However, it should be noted that truncating the duration of dispatch events means that the Maximum STEM Price will now cover more than 80 per cent of all potential STEM price outcomes. It is more likely that Maximum STEM Prices will cover between 85 to 90 per cent of all potential STEM price outcomes under this approach.

The estimates of dispatch event MWh for the Pinjar Units is based on the dispatch profile of all six units over the period 2013-14 to 2018-19.[23] Dispatch event MWh has a normal distribution as shown in Figure 8 and the modelled normal distribution is used in the development of Variable O&M costs per MWh.

[23] 2018-19 only include dispatch information ending February 2019.

Figure 8: Distribution of dispatch event MWh (6 hours or less) – Pinjar Units



Source: Marsden Jacob analysis 2019

Provided in Table 6 is a summary of the starts and operating hours for the Pinjar Units which is used in the modelling of the O&M overhaul cycle (all dispatch events), which showed that the average number of operating hours was around 4 to 5 hours per start across all dispatch events. This reduced to 2.75 hours if only dispatch events less than or equal to 6 hours were considered.

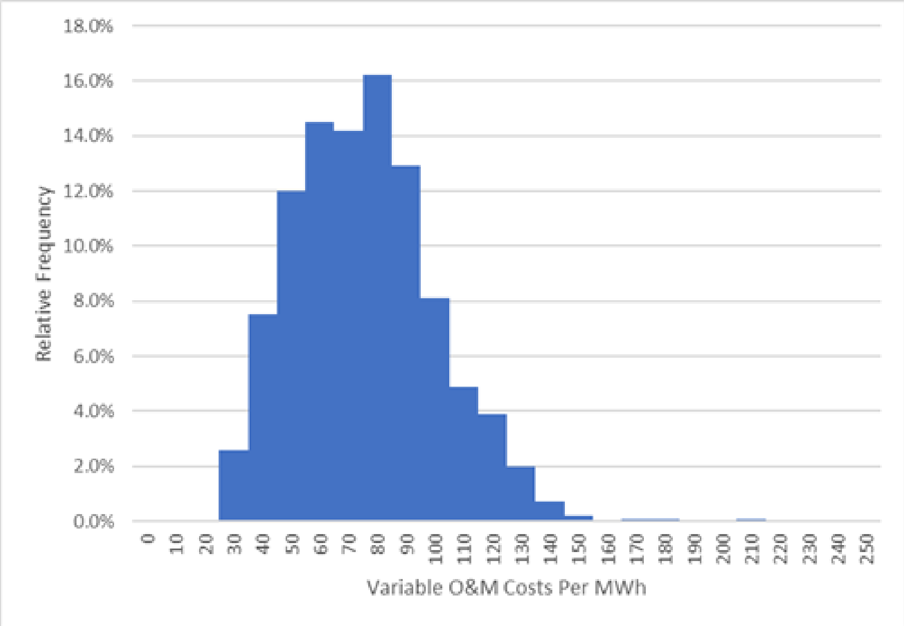
Table 6: Summary of Pinjar Units O&M cycle determination

Measure	Unit	All Dispatch Events	Only Dispatch Events Less Than or Equal to 6 hours duration
Mean	Starts/Year	58	31
Standard deviation	Starts/Year	36	20
Minimum	Starts/Year	12	5
Maximum	Starts/Year	153	86
Operating Hours	Hours/Start	4.5	2.75

Source: Marsden Jacob analysis 2019

Fifthly, using the distribution of start costs (Figure 6) and the distribution of dispatch event MWh (Figure 8), a Monte Carlo simulation was undertaken to develop a distribution of Variable O&M costs ($ per MWh) as shown in Figure 9. The distribution of start costs for the Parkeston Units was derived using the above process and are shown in Appendix One.

Figure 9: Distribution of Variable O&M costs ($/MWh) – Pinjar Units



Source: Marsden Jacob analysis 2019

The distribution of Variable O&M costs for the Pinjar Units is then used in the Monte Carlo simulation to determine the distribution of Maximum STEM Prices.

Based on this distribution, the average O&M cost was calculated to be $70.75 per MWh. This is equivalent to a start cost of $2,724 per start and dispatch event MWh of 38.5 (i.e. $2,724 per start / 38.5 MWh per start) and is like the Variable O&M cost provided by Synergy.[24]

This is significantly lower than the Variable O&M derived in the 2018-19 review ($129.59 per MWh). This is due to the lower generation (in MWh) calculated in the 2018-19 review for the Pinjar Units (26 MWh) for dispatch events less than or equal to 6 hours and the higher maintenance cost per start of $3,320 (i.e. $3,320 / 26 MWh per dispatch event which results in a Variable O&M of $129.59 per MWh). Contributing to the higher maintenance cost was the assumption in previous reviews that the Pinjar Units had a remaining asset life of 44 years; which is not the case (see discussion in Section 2.5.1). Maintenance expenditures are only required to keep the unit's operating until 2030.

Sixthly, the above analysis was only estimating the maintenance component of Variable O&M. Previous studies have based Variable O&M on overhaul costs only – which is typically most of the cost. However, Variable O&M also includes other inputs such as water, labour and lubricants. To ensure that Variable O&M includes all cost components, the above costs have been increased by $1.50 per MWh. This is based on Marsden Jacob's assessment of these costs for an OCGT plant.

3.3 Fuel Prices

3.3.1 Commodity Gas Prices

Under the approach developed in previous reviews of Energy Price Limits, short-run projections of maximum gas prices were developed using an Auto Regressive Integrated Moving Average (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.

[24] Variable O&M costs per MWh had to be estimated given that the dispatch profile for the Pinjar Units is not known with certainty.

For this analysis Marsden Jacob has adopted a similar approach. Variations from the approach are noted below.

The analysis considered different forms of an ARIMA 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).

The statistical analysis found that a model with slight negative growth (constant with first differences) produced the 'best' outcomes. However, analysis of the gas market indicated that declines over recent years have reflected significant capacity coming online. This has resulted in two effects:

- first, levels have declined. Marsden Jacob considers that the declines observed over recent years have incorporated the impact of the increase in gas capacity. It is not considered that there is significant scope for further declines, particularly as prices approach the $2 per GJ floor;
- secondly, there has been a significant reduction in volatility of maximum prices over the past few years. The significant volatility before 2012 is unlikely to be replicated.

For these reasons, Marsden Jacob has used an ARIMA model with no constant term. Reflecting the significant reduction in price volatility in recent years, statistical measures have only been calculated based on data commencing July 2012.[25]

Table 7: Comparison of forecast gas distribution statistics

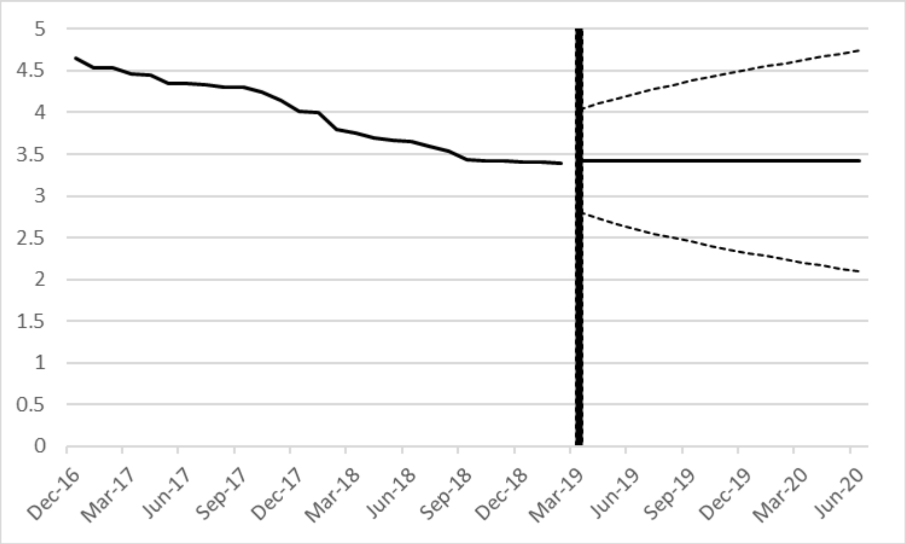
Parameter	2018-19 review	2019-20 review preferred	2019-20 review full period
Average	$4.02	$3.41	$3.44
Median	$4.02	$3.41	$3.44
80% lower bound (10th percentile)	$1.82	$2.55	$1.98
80% upper bound (90th percentile)	$6.23	$4.27	$4.91

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

While the mean gas price remains constant over the period 2019 to 2020, the range of gas outcomes has been increased to reflect the greater uncertainty concerning gas prices remaining at such historically low levels for another 15 months (1 April 2019 to 30 June 2020).

[25] Separate analysis was included using the history back to 2009.

Figure 10: Historical gasTrading monthly maximum prices and ARIMA forecast



Source: Marsden Jacob analysis 2019

3.3.2 Gas Transport Charges

As outlined in Section 2.3.3, the mean value for gas transport charges for gas delivered to both the Pinjar and Parkeston Units has been calculated (assuming a 100 per cent capacity factor):

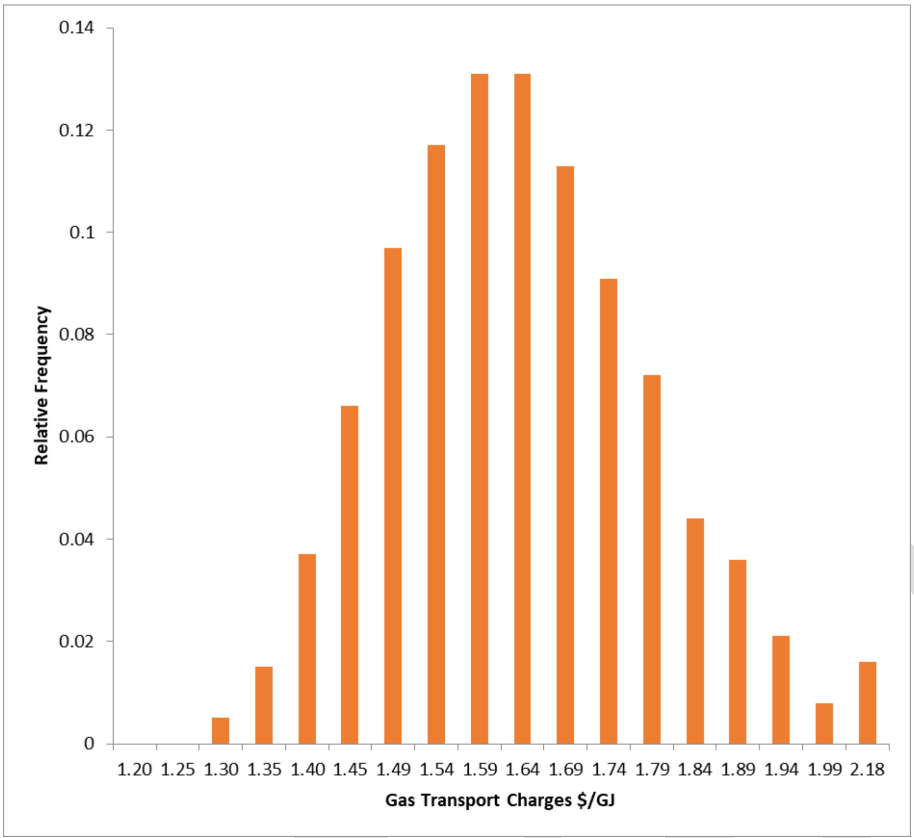
- Pinjar – $1.624 per GJ (based on a 15 per cent premium above the T1 Reference Tariff[26] applicable on the DBNGP). Assuming a standard deviation of $0.15 per GJ.
- Parkeston – $1.5051 per GJ (based on the purchase of spot transport for covered services on the GGP) with a standard deviation of $0.14 per GJ.

The probability density functions were derived for gas transport charges applicable to the Pinjar Units and the Parkeston Units.

The distribution of DBNGP gas transport is based on a log-normal distribution (which helps eliminate the occurrence of negative gas transport costs in statistical analysis). This has then been converted from the log-normal distribution back to a normal distribution for DBNGP transport charges which is shown in Figure 11. The probability density function for GGP transport charges (not shown here) has also been estimated.

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

Figure 11: Distribution of gas transport charges for Pinjar Units ($/GJ) – 100% capacity factor



Source: Marsden Jacob analysis 2019

The gas transport charges in Figure 11 assume the generator is operating at a 100 per cent 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 percent for gas turbines. At this level, gas transport charges would be $1.989 per GJ on the DBNGP instead of $1.624 per GJ, and $1.581 on the GGP instead of $1.5051 per GJ. These higher transport charges (and associated distribution of charges) has been incorporated into the Monte Carlo simulation analysis.

The distribution of gas transport charges is then combined with gas commodity charges to derive a delivered gas price for the Pinjar and Parkeston Units.

3.3.3 Distillate Prices

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 per cent sulphur) or another suitable published price as determined by AEMO[27]. AEMO uses the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore gas oil price (0.5 per cent 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.

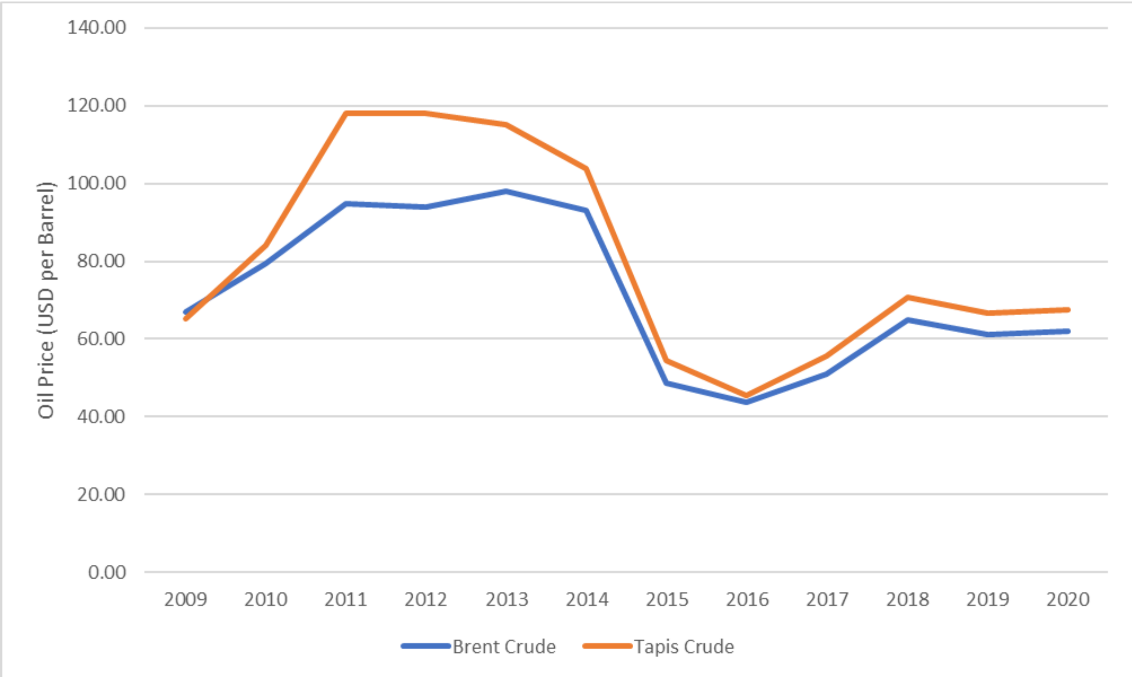
For this purpose, the uncertainty in the distillate price is not statistically important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price, the uncertainty and level of the distillate price is relevant to the extent that it is 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

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

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 12 shows annual average crude oil prices. After the low prices of 2016, prices climbed in 2017 and 2018. The US Energy Information Agency[28] 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 12: 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 per cent 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 $ per GJ.

The outputs are shown in Table 8. In effect, gas prices used to set the Maximum STEM Price should not exceed $21.1 per GJ (Pinjar delivered distillate cost). The standard deviation of distillate prices is estimated to be $1.31 per GJ.

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

Table 8: Reference distillate prices for Pinjar and Parkeston Units 2019-20

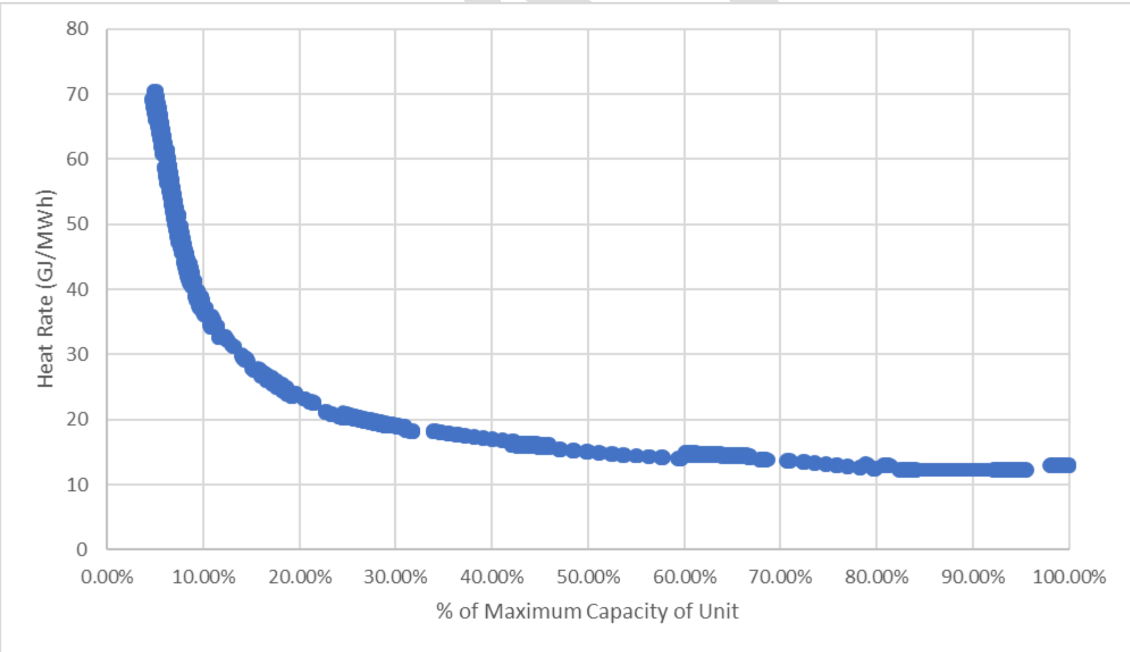
Prices and Taxes	AUD cents per litre (ACPL)	AUD/GJ
Diesel TGP	134.5	
Excise	42.2	
GST	12.2	
Diesel TGP	80.1	20.7
Delivery Cost to Pinjar	1.22	
Delivery Cost to Parkeston	1.05	
Delivered Cost to Pinjar	81.3	21.1
Delivered Cost to Parkeston	81.1	21.0

Source: Marsden Jacob analysis 2019

3.4 OCGT Heat Rates

Heat rates of the Pinjar and Parkeston Units were derived using information provided by Synergy and Goldfields Power Pty Ltd respectively. Figure 13 shows the typical heat rate of 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).

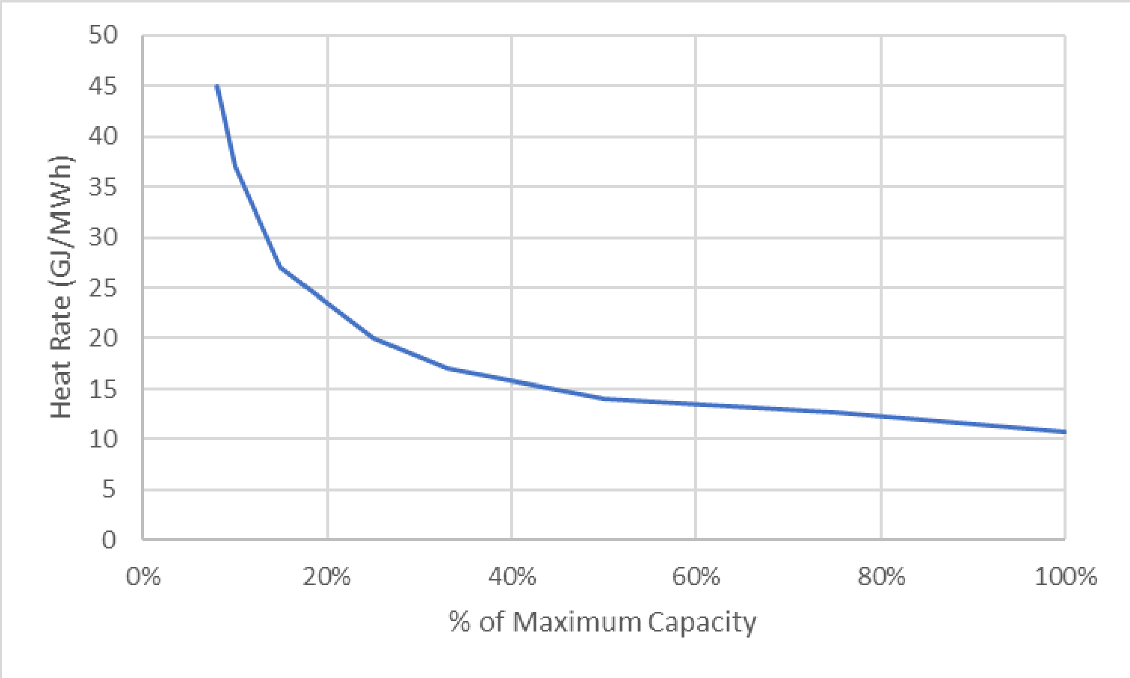
Figure 13: Typical heat rate of 40 MW OCGT units – 15 degrees Celsius / 30 per cent humidity



Source: Marsden Jacob analysis 2019

The heat rate for 40 MW aero derivative units are shown in Figure 14. In the range of 5 to 15 per cent utilisation, the 40 MW aero derivative units are much more efficient than the OCGT units. However, as more capacity is utilised, the heat rates for the generators are similar.

Figure 14: Typical heat rate 40 MW aero derivative units



Source: Marsden Jacob analysis 2019

3.4.1 Start-Up Energy Consumption

Start-up heat energy was assumed to average 3.5 GJ per start for each turbine. Start-up energy consumption is aggregated across all generation for that start. For a Pinjar Unit operating at 75 per cent capacity utilisation, the 3.5 GJ used to start the turbine is equivalent to an additional 15 minutes of operation for a single MW. For most simulated starts, this cost accounts for less than $0.50 per MWh of the Maximum STEM Price.

3.5 Loss Factors

Transmission loss factors that are used to determine how much sent out electricity is delivered to the regional reference node (Muja)[29]. 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.

Table 9 lists the Loss Factors for the 2018-19 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 in the SWIS. Pinjar's loss factor is close to the median SWIS loss factor value of 1.0397.

Table 9: Loss factors for Pinjar and Parkeston Units

Loss Factor Area Code	Description	Loss Factor	StartDate
WPJR	Pinjar	1.0322	1-Jul-18
WPKS	Parkeston	1.1686	1-Jul-18

Source: Western Power, 2018-19 Transmission Loss Factors

[29] Chapter 11 of the WEM Rules

4. Modelling Results

4.1 Maximum STEM Price

Modelling results presented in this chapter are 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.

- Five random variables are created for each simulation;
  - Fuel commodity cost ($ per GJ);
  - Fuel transport cost ($ per GJ);
  - Variable O&M ($ per MWh);
  - Average generation (MW) when dispatched;
  - Run hours (h);
- Mean heat rate is function of the average dispatch generation which is based on historic generation from 2014-2018 for Pinjar and 2018 for Parkeston;
- Fixed start-up costs are aggregated over all generation (MWh) for that start (Average Generation (MW) x Run Hours (h)).

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 (38.5 MWh per dispatch event) results in the plant operating at higher points on the heat rate curve when compared to the Parkeston Units (49 MWh per dispatch event).

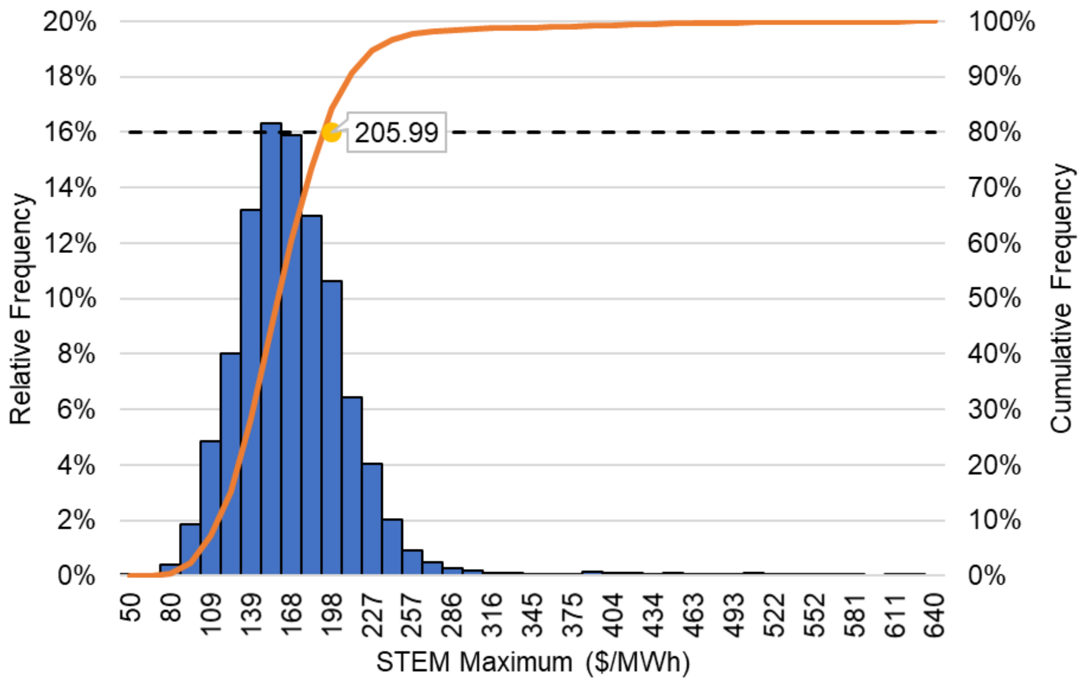
Table 10: Calculation of Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M	$/MWh	70.75
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost	$/MWh	112.28
Loss Factor		1.03
Before Risk Margin	$/MWh	178.01
Risk Margin Added	$/MWh	27.98
Risk Margin Value	%	15.70
Assessed Maximum STEM Price	$/MWh	205.99

Source: Marsden Jacob analysis 2019

The probability density function for the Maximum STEM Price based on the Pinjar Units is provided in Figure 15. It also shows the 80th percentile of Maximum STEM Price outcomes.

Figure 15: Maximum STEM Price probability density function (based on Pinjar Units)



Source: Marsden Jacob analysis 2019

The Maximum STEM Price based on the Parkeston Units is shown in Table 11.

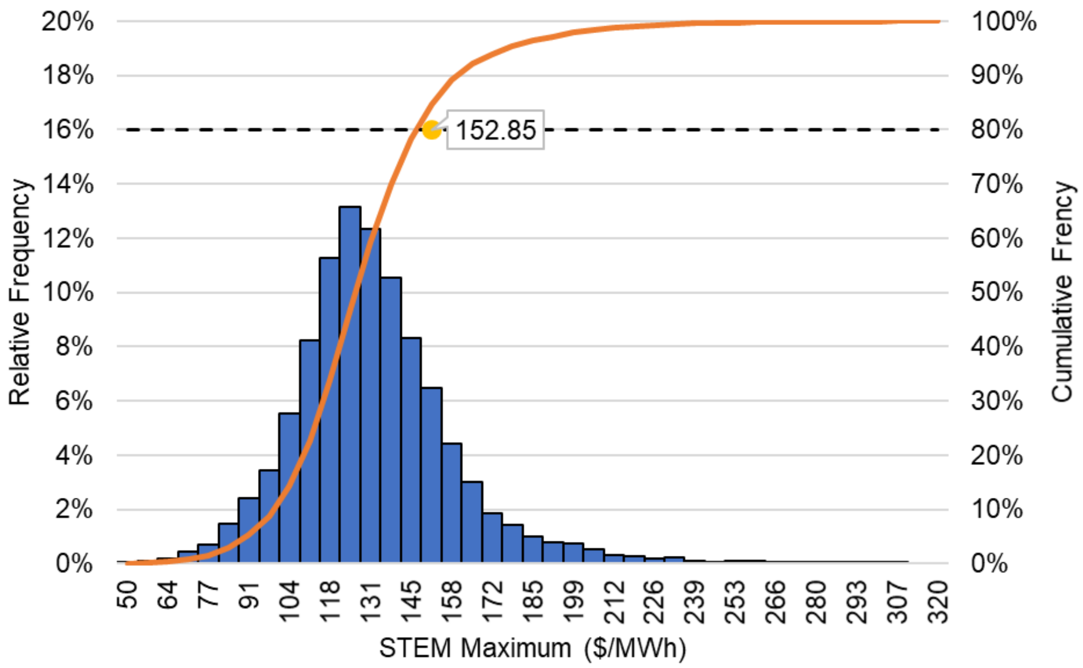
Table 11: Calculation of Maximum STEM Price with Parkeston Units

Component	Units	Values
Mean Variable O&M	$/MWh	84.23
Mean Heat Rate	GJ/MWh	13.85
Mean Fuel Cost	$/MWh	73.48
Loss Factor		1.17
Before Risk Margin	$/MWh	135.38
Risk Margin Added	$/MWh	17.47
Risk Margin Value	%	12.90
Assessed Maximum STEM Price	$/MWh	152.85

Source: Marsden Jacob analysis 2019

The probability density function for the Maximum STEM Price based on the Parkeston Units is provided in Figure 16. It also shows the 80th percentile of Maximum STEM Price outcomes.

Figure 16: Maximum STEM Price probability density function (based on Parkeston Units)



Source: Marsden Jacob Analysis 2019

The calculated Risk Margin, which is the difference between the mean and 80th percentile, is provided in Table 12.

Table 12: Risk Margin

	Mean	80% Cost Coverage	Risk Margin
Pinjar Units	178.01	205.99	15.7%
Parkeston Units	135.38	152.85	12.9%

Source: Marsden Jacob Analysis 2019

4.2 Alternative Maximum STEM Price

The assessed Alternative Maximum STEM Price (using distillate) for both the Pinjar and Parkeston Units are shown in Table 13 and Table 14 respectively.

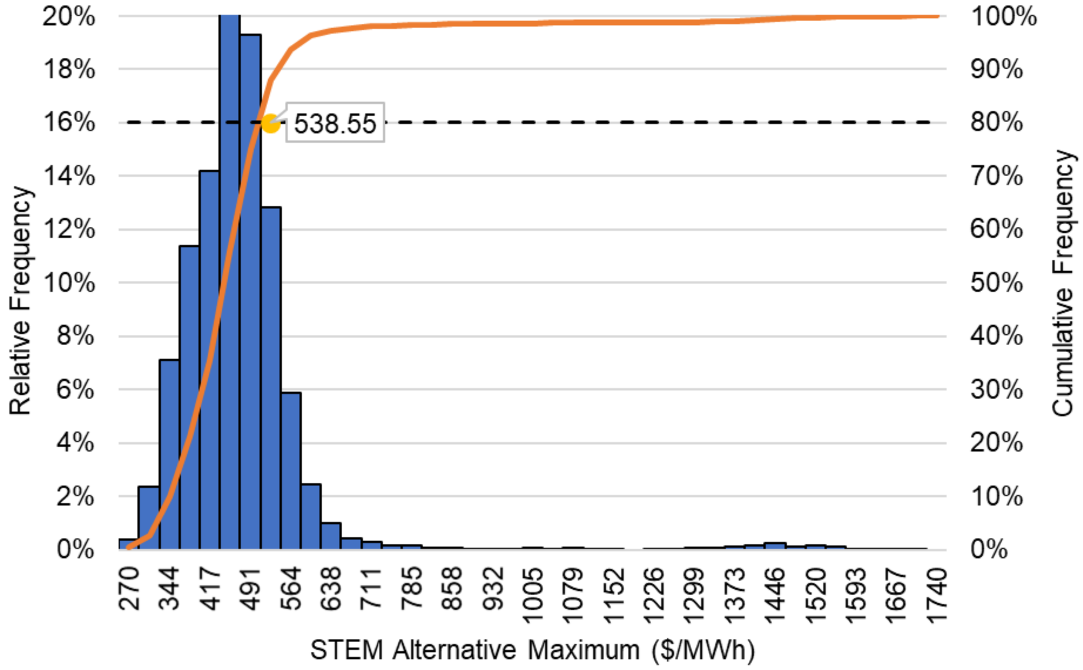
Table 13: Calculation of the Alternative Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M	$/MWh	70.75
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost	$/MWh	434.22
Loss Factor		1.03
Before Risk Margin	$/MWh	491.98
Risk Margin Added	$/MWh	46.56
Risk Margin Value	%	9.50
Assessed Alternative Maximum STEM Price	$/MWh	538.55

Source: Marsden Jacob analysis 2019

The probability density function for the Maximum STEM Price based on the Pinjar Units is shown in Figure 17. It also shows the 80th percentile of Maximum STEM Price outcomes.

Figure 17: Alternative Maximum STEM Price probability density function (based on Pinjar Units)



Source: Marsden Jacob analysis 2019

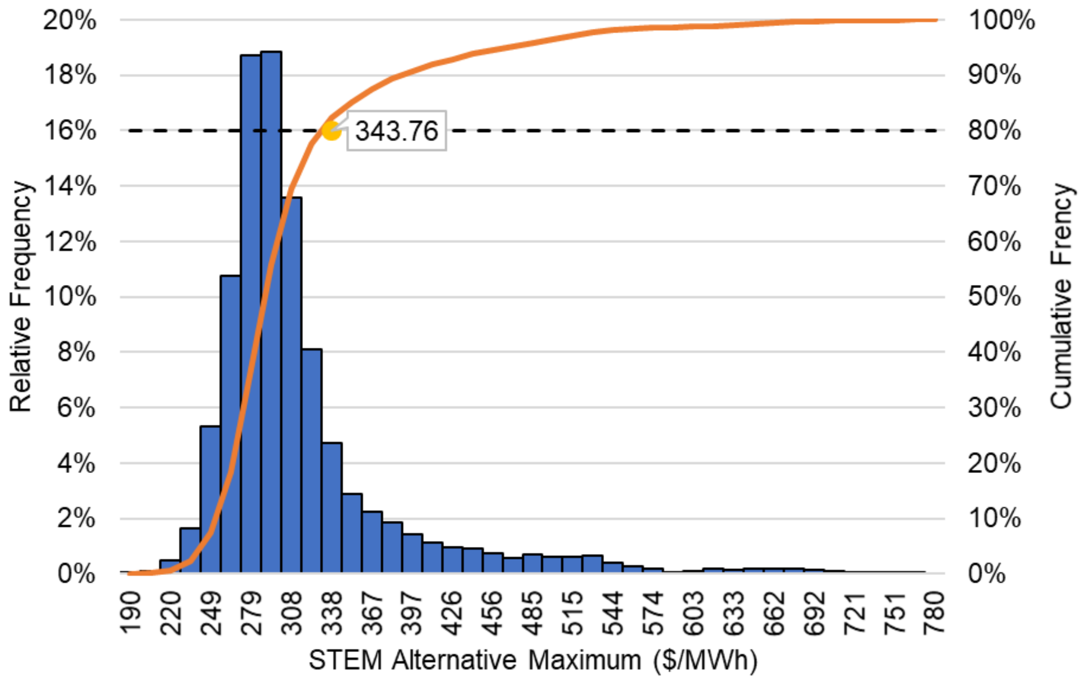
The Alternative Maximum STEM Price (using distillate) for the Parkeston Units and the probability density function of price outcomes is shown in Table 14 and Figure 18 respectively.

Table 14: Calculation of the Alternative Maximum STEM Price with Parkeston Units

Component	Units	Values
Mean Variable O&M	$/MWh	84.23
Mean Heat Rate	GJ/MWh	13.85
Mean Fuel Cost	$/MWh	291.49
Loss Factor		1.17
Before Risk Margin	$/MWh	323.16
Risk Margin Added	$/MWh	20.61
Risk Margin Value	%	6.40
Assessed Alternative Maximum STEM Price	$/MWh	343.76

Source: Marsden Jacob analysis 2019

Figure 18: Alternative Maximum STEM Price probability density function (based on Parkeston Units)



Source: Marsden Jacob analysis 2019

4.3 Regression of Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate[30]. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost.

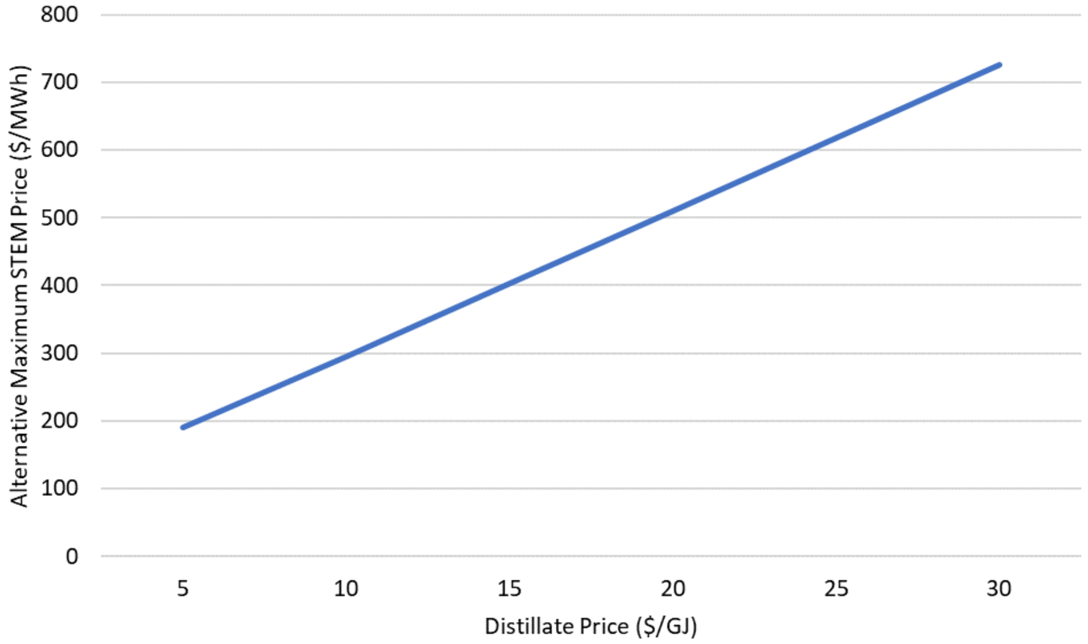
The price components for the Alternative Maximum STEM Price that provide the 80 per cent cumulative probability price are:

$81.655 per MWh + 21.44 multiplied by the Delivered Distillate Price ($ per GJ) (5)

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 per GJ, to assess the 80 per cent probability level of cost for each fuel price. Rather than taking the 80 per cent probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80 per cent price versus distillate price. The relationship using the function in equation (5) is shown in Figure 19.

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

Figure 19: Assessed Alternative Maximum STEM Price vs delivered distillate price for Pinjar Units



Source: Marsden Jacob Analysis 2019

4.4 Changes in Energy Price Limits Compared to Previous Years

A comparison of the assessed upper price limits for 2019-20 with the previous year's upper price limits is provided in Table 15.

Table 15: Comparison of Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M	$/MWh	70.75	129.59	-58.84
Mean Heat Rate	GJ/MWh	20.62	19.22	1.4
Mean Fuel Cost	$/GJ	112.28	121.31	-9.03
Loss Factor		1.03	1.03	0.00
Before Risk Margin	$/MWh	178.01	243.07	-65.06
Risk Margin Added	$/MWh	27.98	58.93	-30.95
Risk Margin Value	%	15.7	24.2	-8.5
Assessed Maximum STEM Price	$/MWh	205.99	302	-96.01

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

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

1. Lower *Mean Variable O&M Cost* ($70.75 per MWh compared to $129.59 per MWh last year). The Mean Variable O&M Cost per MWh is equal to the Mean Variable O&M cost per start divided by Dispatch Event MWh (for dispatch events of 6 hours or less duration).

    a. *Mean Variable O&M Cost per MWh* – as outlined in Section 3.2, Marsden Jacob have determined that the Mean Variable O&M cost per start for the Pinjar Units is $2,724 per start for 2019-20, whereas the equivalent cost used in developing the 2018-19 Maximum STEM Price was $3,320 per start and was $4,279 per start in 2017-18. The significant reduction in the Mean Variable O&M cost per start from 2017-18 to 2018-19 was due to a change in the methodology used to calculate this variable (e.g. excluding overhaul costs incurred in the last 3 years of the plant's life). The Mean Variable O&M cost per start for 2018-19 was a modelled outcome and did not refer to the actual maintenance cycle or costs incurred in maintaining the Pinjar Units. Synergy did not provide any relevant information in the 2018-19 review. Synergy has provided confidential information pertaining to unit asset lives and O&M costs for the determination of Energy Price Limits in 2019-20. This information suggests that Mean Variable O&M costs per start for the Pinjar Units are significantly below previous (modelled) estimates. This has been factored into the determination of maintenance costs.

    b. Marsden Jacob calculated *Dispatch Event MWh* for events of 6 hours or less duration. This included data for all Pinjar Units over the period 2013-14 to 2018-19 (ending February 2019). It was found that across all Pinjar Units, the average generation output was 38.5 MWh per event. The equivalent amount calculated for last year's Energy Price Limits calculation was 26 MWh. Previous reviews have typically found that Dispatch Event MWh (6 hours or less) was around 26 MWh.

    c. Therefore, the *Mean Variable O&M Cost* for 2019-20 is calculated to be $70.75 per MWh (i.e. $2724 per start / 38.5 MWh per start). The Variable O&M Cost for 2018-19 was calculated to be $129.59 per MWh (i.e. $3,320 / 26 MWh per start).

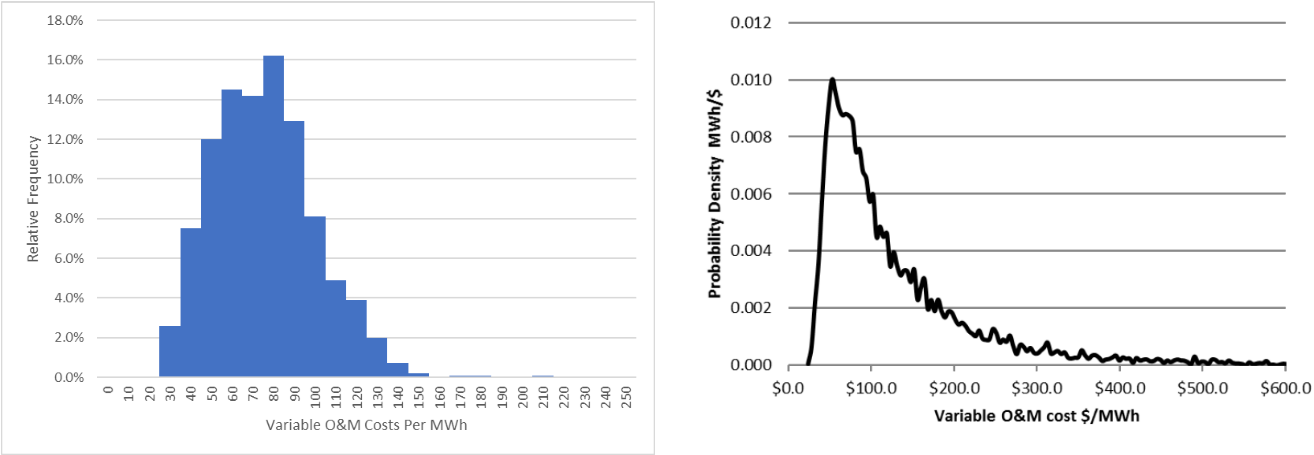
    It should be pointed out the calculation of the mean variable O&M Cost for the Pinjar Units has been highly volatile. The 2018-19 cost was $129.59 per MWh, was $158.93 per MWh in 2017-18, and was as low as $57.18 MWh in 2016-17 (all above Variable O&M costs listed are before application of the loss factor). To a large extent this has resulted from changes in underlying modelling methodologies and has not reflected actual costs of maintaining the Pinjar Units. The methodology and calculations for 2019-20 have determined that the Variable O&M costs are closer to the previous lower estimates for the Pinjar Units.

2. Lower *Mean Fuel Cost* ($9.03 per GJ lower in 2019-20) resulting from lower gas commodity prices. The delivered cost of (spot) gas is forecast to be $5.445 per GJ for 2019-20. The mean delivered spot gas cost was forecast to be $6.31 per GJ in 2018-19. The lower delivered spot price for gas has resulted due to the continued over supply of gas in the domestic market, which resulted in average spot gas price forecasts reducing to $3.41 per GJ in 2019-20, compared to average spot prices of $4.00 per GJ for 2018-19. The underlying spot gas price forecast used in the 2018-19 review was $4.02 per GJ.

3. Reduced *Risk Margin Value* due to a smaller variance in the distribution of Maximum STEM Prices, which is mainly a function of the reduced variance in Variable O&M Costs and delivered (spot) gas prices.

    As outlined in Point (1) above, modelled mean Variable O&M costs ($ per MWh) have fallen. In addition, the modelling of Variable O&M Costs in 2019-20 has a significantly narrower probability distribution function when compared to the modelling undertaken to support Energy Price Limits in 2018-19. The probability density functions for Variable O&M for this year is compared with the PDF for last year in Figure 20.

Figure 20: Comparison of PDF for Variable O&M Costs ($/MWh) for Pinjar Units – Left (2019-20) and Right (2018-19)

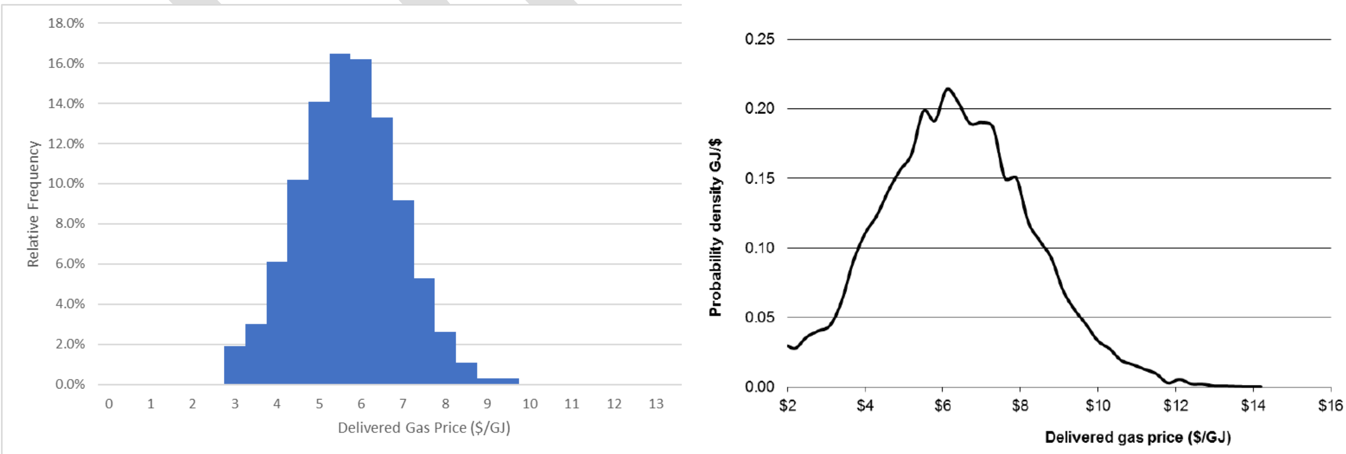


Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

This highlights the considerable range of Variable O&M Costs that could occur under the modelling undertaken in the 2018-19 review. Variable O&M costs can be as high as $600 per MWh in last years modelling, whereas modelling for setting the 2019-20 Energy Price Limits indicates that the maximum Variable O&M costs are only likely to be around $208 per MWh for the Pinjar Units. As a result of the significantly higher range of values modelled in previous reviews, mean Variable O&M costs ($129.59 per MWh) are substantially above the median cost ($96 per MWh), and the standard deviation of costs is $99.15 per MWh. The estimated standard deviation of Variable O&M costs calculated for the 2019-20 review is $24 per MWh, with a mean of $71 per MWh. The 80th percentile of Variable O&M costs is around $90 per MWh.

The distribution of delivered gas prices also has a significant influence on the distribution of Maximum STEM Prices. The significantly wider distribution of delivered gas prices in the 2018-19 review contributed to increasing the 80th percentile for the Maximum STEM Prices in 2018-19. The PDFs for delivered gas prices for 2019-20 and 2018-19 setting of Energy Price Limits are shown in Figure 21.

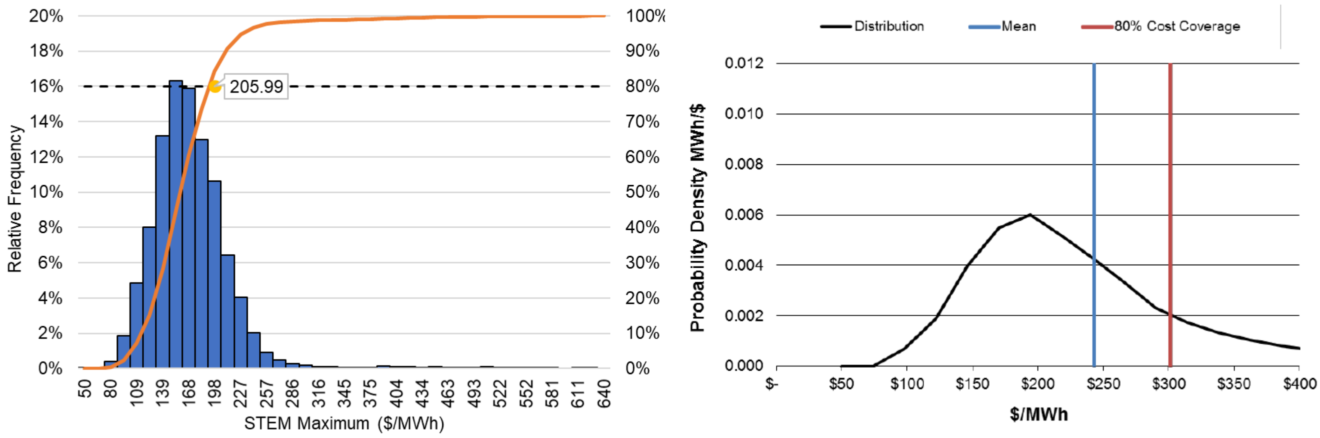
Figure 21: Comparison of PDF for Delivered Gas Costs ($/GJ) for Pinjar Units – Left (2019-20) and Right (2018-19)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

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 PDFs for 2018-19 and 2019-20 Maximum STEM Prices are provided in Figure 22.

Figure 22: Comparison of PDF for Maximum STEM Prices ($/MWh) for Pinjar Units – Left (2019-20) and Right (2018-19)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

While the Maximum STEM Price has reduced, the Alternative Maximum STEM Price has increased compared to last year. The lower Mean Variable O&M cost has been offset by a higher Mean Fuel Cost due to higher distillate prices. The Risk Margin is also lower due to the reduced variance in the distribution of Alternative Maximum STEM price outcomes.

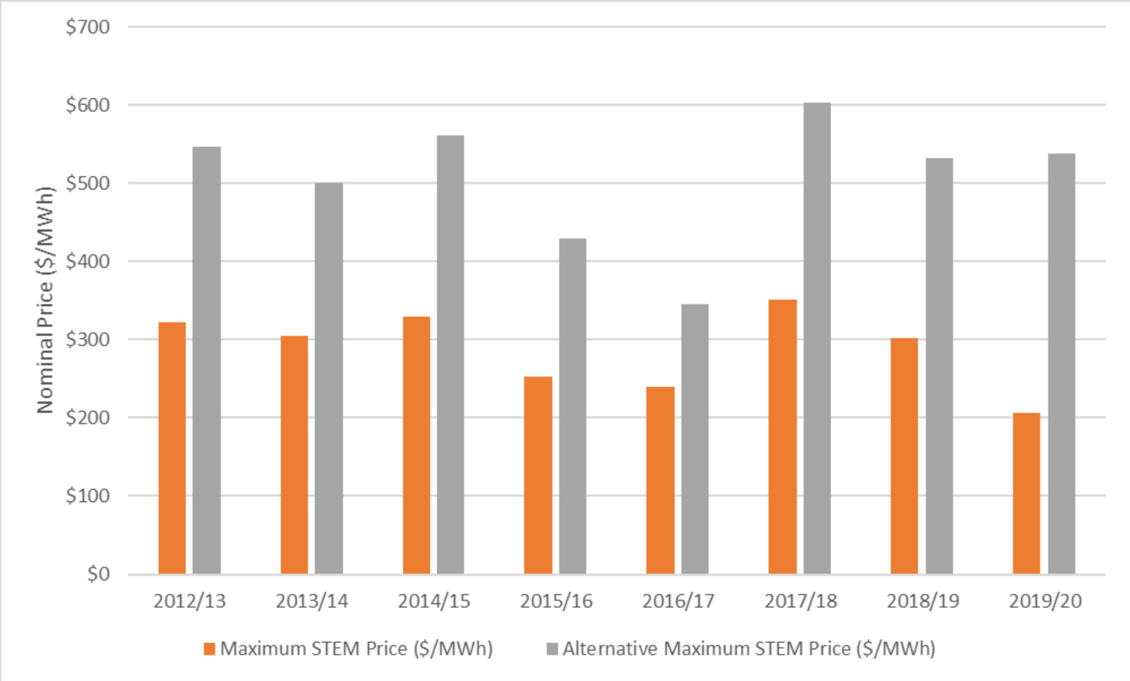
Table 16: Comparison of Alternative Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M	$/MWh	70.75	129.59	-58.84
Mean Heat Rate	GJ/MWh	20.62	19.28	1.34
Mean Fuel Cost	$/GJ	434.22	351.42	82.8
Loss Factor		1.03	1.03	0.00
Before Risk Margin	$/MWh	491.98	466	25.98
Risk Margin Added	$/MWh	46.56	67	-20.44
Risk Margin Value	%	9.5	14.4	-4.9
Assessed Alternative Maximum STEM Price	$/MWh	538.55	533	5.55

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

A comparison of assessed upper prices with historical outcomes is provided in Figure 23. What this shows is that the assessed Maximum STEM Price is the lowest price (in nominal dollars) since 2012-13. This is broadly consistent with lower commodity gas prices that are projected for 2019-20. However, the reduction in Variable O&M and Risk Margin in 2019-20 are also significant factors (the latter is also a function of the reduce variance in commodity gas prices). On the other hand, the Alternative Maximum STEM Price is slightly higher than last year, resulting from higher distillate prices that have increased in response to rising forecast crude oil prices.

Figure 23: Comparison of assessed upper Energy Price Limits with historical prices



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

5. Appendix One: Determination of Key Parameters for the Parkeston Aero Derivative Units

As outlined in Section 2.2, the Parkeston Units provide electricity to a major mining customer in the Goldfields Region, while also providing peaking energy in the STEM and Balancing Market. Usually, Unit 1 (GO1) provides energy to the baseload mine, while Units 2 and 3 are providing back-up to Unit 1 and participating in the Balancing Market. This makes it problematical when using the Parkeston Units as a benchmark for establishing energy price limits, since the maintenance overhaul cycle for Unit 1 will be driven by operating hours, while the overhaul cycle for Units 2 and 3 will be largely dictated by their participation in the Balancing Market.

For this study, we have based the calculation of overhaul costs on the dispatch profile of Units 2 and 3 participating in the Balancing Market. The calculation of levelised overhaul costs is $3,502 per start for the mean number of starts of 66.5 (based on the latest two years of starts) and is shown in Table 17 along with the overhaul cycle costs.

Table 17: Overhaul costs and levelised cost per start for Parkeston Units – 66.5 Starts Per Annum

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	$1,268,704	1	$1,268,704	
B	1200	$3,353,841	1	$3,353,841	
A	1800	$1,268,704	1	$1,268,704	
C	2400	$4,843,906	1	$4,843,906	
Total Cost		$10,735,154		$10,735,154	$2,430,254
Cost Per Start (a)		$4,472.98	Levelised Cost Per Start (b)		$3,183.22
Unscheduled Maintenance Cost Contingency		20%	Unscheduled Maintenance Cost Contingency		10%
Starts / Year		66.5	NPV of Starts		763
Cost Per Start (including Contingency)		$5,368	Cost Per Start (including Contingency)		$3,502

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

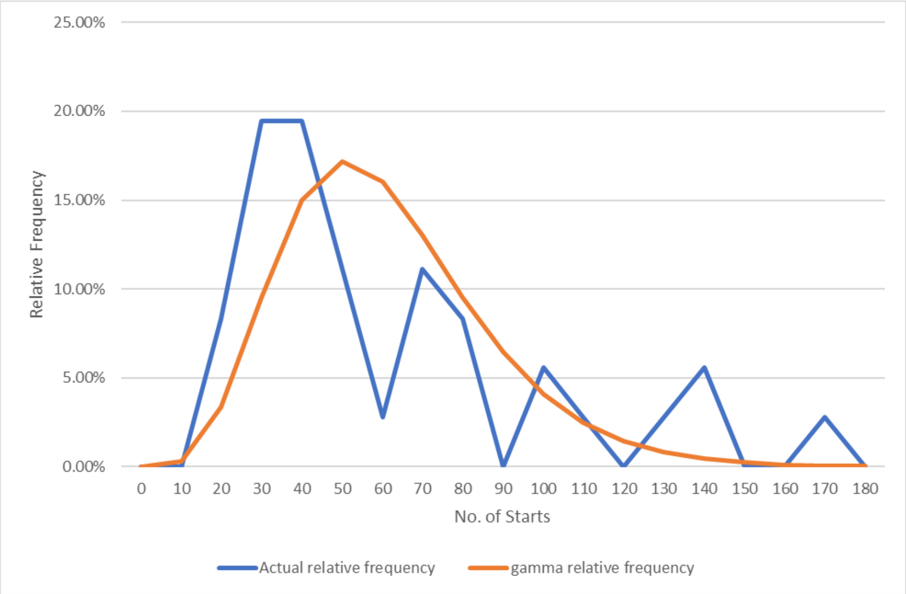
(b) NPV of Overhaul Costs divided by NPV of Starts

Source: Marsden Jacob analysis 2019

The calculation of Parkeston O&M Costs follows the six-step methodology outlined in Section 3.2 for the Pinjar Units. Shown in Figure 24 are the distribution of the number of starts, relationship between starts and Variable O&M, and the distribution of Variable O&M per MWh for the Parkeston Units. The distribution of Variable O&M per MWh is used in the Monte Carlo analysis to determine the Maximum and Alternative Maximum STEM Prices. The distribution of starts in Figure 24 is based on the distribution for the Pinjar Units.

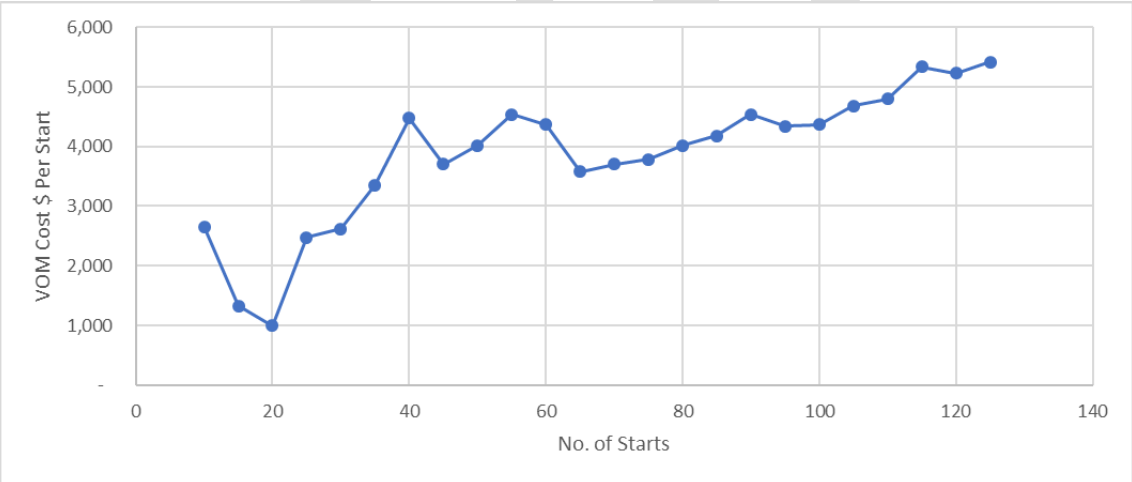
The sample size for the number of starts for the Parkeston Units was insufficient to derive a reasonable probability density function.

Figure 24: Distribution of the number of starts – Parkeston Units (2 and 3 only)



Source: Marsden Jacob analysis 2019

Figure 25: Relationship between Variable O&M costs per start and number of starts – Parkeston Units (2 and 3 only)



Source: Marsden Jacob analysis 2019

Figure 26: Distribution of dispatch event MWh (6 hours or less) – Parkeston Units (2 and 3 only)

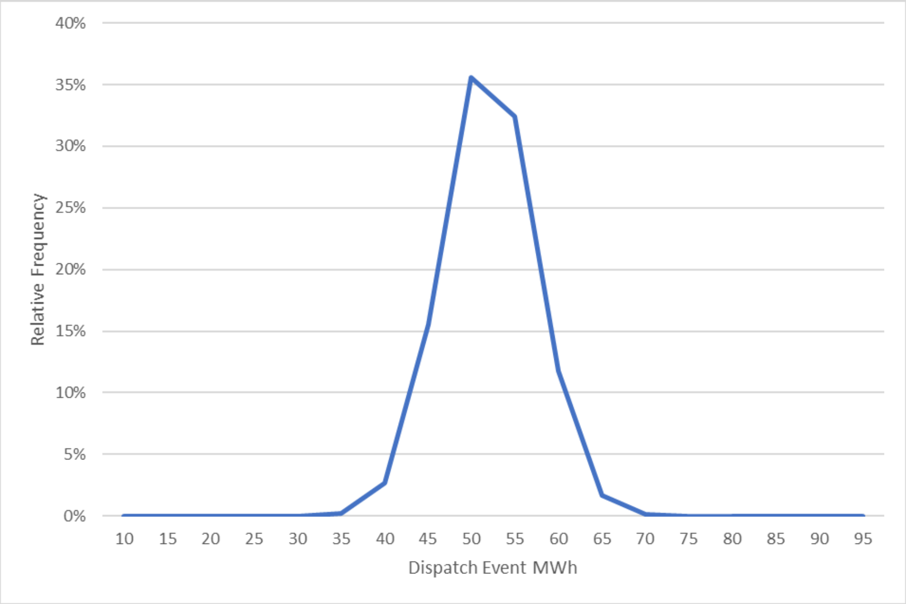
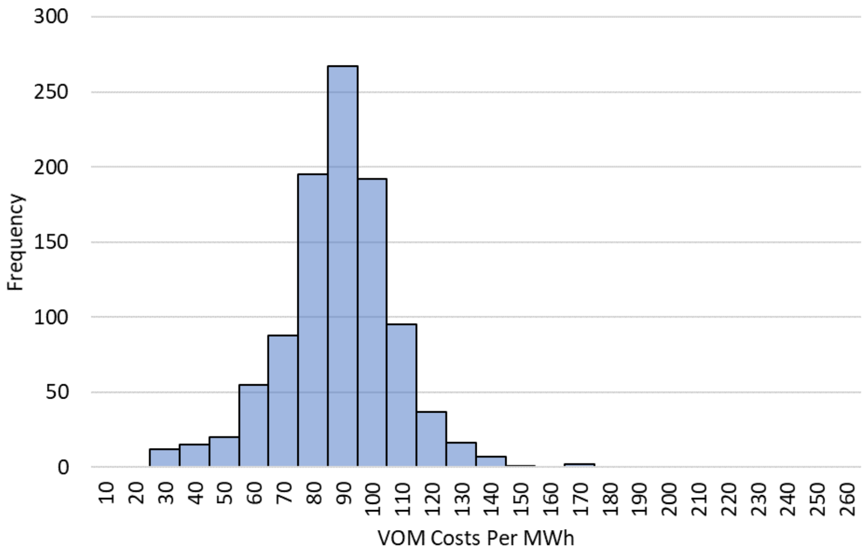


Figure 27: Distribution of Variable O&M costs ($/MWh) from overhaul costs for Parkeston Units (2 and 3 only)



Source: Marsden Jacob analysis 2019