2017 Energy Price Limits Decision

September 2017

Economic Regulation Authority
WESTERN AUSTRALIA

Economic Regulation Authority

4th Floor Albert Facey House
469 Wellington Street, Perth

Mail to:
Perth BC, PO Box 8469
PERTH WA 6849

T: 08 6557 7900

F: 08 6557 7999

E: records@erawa.com.au

W: www.erawa.com.au

National Relay Service TTY: 13 36 77

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1. Decision

In accordance with clause 2.26 of the *Wholesale Electricity Market Rules (1 September 2017)* (**market rules**), the Economic Regulation Authority approves:

1. the proposed revised value for the maximum Short Term Energy Market (**STEM**) price of $351/MWh; and

2. the proposed price components for the alternative maximum STEM price:

   $227.88/MWh + 19.256 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ[1]

In accordance with clause 6.20.11 of the market rules, the approved revised values for the maximum STEM price and the alternative maximum STEM price will apply with effect from the time specified in a notice to be published on the Australian Energy Market Operator's website.

2. Background

The Wholesale Electricity Market (**WEM**) comprises a capacity market to meet peak demand in the system and an energy and ancillary services market to meet real-time demand based on the capacity available. The capacity market provides sufficient recovery of fixed costs to meet the reliability objective of the WEM. Supply offers in the energy markets (STEM and balancing) are based on the short-run marginal cost (**SRMC**) of supply and the market clearing price is determined by the SRMC of the marginal energy resource. Together, these markets emulate the outcomes of a competitive market.

As part of the market power mitigation mechanisms in the WEM, price caps are set based on the SRMC of the highest cost generating works in the South West Interconnected System. Participants in the WEM must bid for or offer energy in the STEM and balancing market within the energy price limits, as provided for under the market rules.[2]

In accordance with clause 6.20.1 of the market rules, the energy price limits are a set of price limits comprising:

- the maximum STEM price;

- the alternative maximum STEM price; and

- the minimum STEM price.[3]

The maximum price depends on whether gas or liquid fuelled generation is required to meet the electricity demand. The maximum STEM price is applied when gas-fuelled generation is required, and the alternative maximum STEM price is applied when liquid-fuelled generation is required. Under the market rules, the minimum STEM price is fixed at negative $1,000/MWh.

[1] Currently based on the Perth Terminal Gate Price (less excise and GST).

[2] Other market power mitigation mechanisms in the WEM include mandatory provision of capacity in the STEM and balancing markets (based on expected SRMC) and ex post market monitoring/screening.

[3] Clause 7A.2.4

There are trade-offs in setting the maximum STEM price. The price limit is required to be:

- low enough to mitigate the exercise of market power;
- high enough so that the highest cost generating works in the South West Interconnected System (**SWIS**) is able to recover its SRMC; and
- high enough so that short-term volatilities in the gas market (resulting from excessive gas prices, beyond the basis for the estimation of the maximum STEM price) do not contribute to a regular switching of dual fuel capability units to liquid fuel.[4]

The market rules require the Australian Energy Market Operator (**AEMO**) to annually review the appropriateness of the value of the maximum STEM price and alternative maximum STEM price.[5] AEMO may propose revised values for the maximum STEM price and the alternative maximum STEM price[6] after conducting a review based on the method set out in clause 6.20.7(b) of the market rules.

The maximum STEM price or alternative maximum STEM price must be calculated using the following formula:

$$(1 + risk\ margin) \times \frac{variable\ O\&M + (heat\ rate \times fuel\ cost)}{loss\ factor}$$

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 (**O&M**) cost of a 40 MW open cycle gas turbine generating station, expressed in $/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/MWh;
- fuel cost is the mean unit fixed and variable fuel cost of a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and
- loss factor is the marginal loss factor of a 40 MW open cycle gas turbine generating station relative to the reference node.[7]

AEMO must determine appropriate values for the factors described above, as applicable to the maximum STEM price and alternative maximum STEM price.

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[4] For instance, if the maximum STEM price is set too low and during a trading interval gas price peaks at excessively high prices, a gas generator may not be able to recover its SRMC. Under such conditions, the generator (with dual fuel capability) may run the machine with the liquid fuel to be able to recover its costs, noting that the alternative maximum STEM price is generally greater than the maximum STEM price.

[5] Clause 6.20.6 of the market rules.

[6] Clause 6.20.7 of the market rules.

[7] Under the market rules, the reference node is defined as the Muja 330 bus-bar (relative to which loss factors are defined).

AEMO is required to prepare a draft report describing how it arrived at proposed revised values of energy price limits, including the details of factors used in the calculations. AEMO must publish the report on the market website, advertise the report in newspapers widely published in Western Australia, and request submissions from all sectors of the Western Australian energy industry, including end-users, within six weeks of the date of publication.[8]

After considering the submissions on the draft report, AEMO must propose final revised values for any change to energy price limits and submit the values in its final report, along with submissions received on the draft report, to the Economic Regulation Authority (**ERA**) for approval.[9]

The market rules require the ERA to review the final report provided by AEMO and all submissions received by AEMO in the preparation of the report, and decide whether to approve any revised value of the energy price limits.[10] In making its decision, the ERA must consider only:[11]

- whether the revised value for the energy price limit proposed by AEMO reasonably reflects the application of the method and guiding principles for calculating the energy price limits described in clause 6.20 of the market rules; and
- whether AEMO has carried out an adequate public consultation process.

3. AEMO's process

Consistent with the approach in previous years, AEMO engaged Jacobs Group (Australia) (**Jacobs**) to assist it in undertaking the 2017 energy price limits review. Jacobs prepared a draft report, which AEMO released for public consultation on 28 March 2017.[12]

The consultation period on Jacobs' draft report closed on 9 May 2017. AEMO did not receive any submissions from stakeholders.

On 15 June 2017, AEMO provided the ERA with its proposed values for the energy price limits, together with Jacobs' report on the review of the energy price limits. AEMO suggested that the proposed energy price limits would take effect on 1 July 2017.

The ERA conducted a detailed review of Jacobs' report and determined that the method adopted for the estimation of variable O&M costs had conceptual shortcomings. The ERA directed AEMO to revise the applied method.

Subsequently, AEMO investigated the queries raised by the ERA and revised the method used for the calculation of the variable O&M costs. AEMO also revised some of the underlying assumptions for the estimation of the O&M costs. AEMO's revision of the report led to significant changes in the proposed maximum STEM price and the alternative maximum STEM price.

[8] Clause 6.20.9 of the market rules.

[9] Clause 6.20.10 of the market rules.

[10] Clause 2.26.1 of the market rules.

[11] Clause 2.26.1(c) of the market rules.

[12] See AEMO website, 2017 Energy Price Limits Review, https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/WA_WEM_Consultation_Documents/2017/Price-limits-review/Jacobs-Draft-Report.pdf

On 15 August 2017, AEMO published a draft of the revised report for the review of the energy price limits and conducted a two-week consultation process with market participants, focused on the changes made in the revised report. AEMO received a submission from Perth Energy.

On 6 September 2017, AEMO provided the ERA with its revised proposed energy price limits, Jacobs' revised report and Perth Energy's submission. AEMO proposed that the revised price limits would take effect on 1 October 2017.

Table 1 provides a summary of the main differences in the proposed energy price limits and the calculation input parameters between Jacobs' previous report and its revised report.

Table 1. Summary of changes in the calculation inputs and proposed energy price limits

Parameter	Value in previous report	Value in revised report (variation from previous report)	Change reason
Maximum STEM price ($/MWh)	245	351 (+106)	Changes in the method used for calculating variable O&M costs to account for the time value of money and risk appropriately.
Non-fuel coefficient of alternative maximum STEM price ($/MWh)	100.65	227.88 (+127.23)	
Alternative maximum STEM price ($/MWh)*	424	544 (+120)	
Total O&M cycle costs (2017 million $)	12.3	10.0 (-2.3)	Revisions to conservative assumptions on the replacement of machine parts.
Escalation factor to represent the O&M cost impact of peaking duty to cover unscheduled maintenance	20 per cent escalation factor applied to discounted maintenance cycle costs	20 per cent escalation factor applied to the average number of starts per year	Revised to be used as a multiplier on the number of starts, as opposed to applying it as a cost uplift.

* Based on a projected distillate price of $16.43/GJ for the month of July 2017.

For comparison, Table 2 lists the existing and proposed maximum STEM price following the changes outlined above.

Table 2. Existing and proposed maximum STEM price

Effective date	Maximum STEM price ($/MWh)
1 July 2016 (approved by the ERA)	240
1 October 2017 (proposed by AEMO)	351

Jacobs' report notes major changes among the components of the maximum STEM price when compared to those from last year's review. A significant upward change (of $124.4/MWh) due to rising variable O&M costs is partly offset by a downward movement (of $17.0/MWh) caused by a declining forecast gas price. In comparison with the forecast from last year, the lower historical spot gas prices over the past 12 months have contributed to a lower forecast gas price.

Figure 9 of Jacobs' final report provides a summary of the movement in costs. The increase in variable O&M cost is driven primarily by the revised method of calculating the variable maintenance costs, and a significant increase in the expected number of starts per annum for the highest cost generating works in the SWIS. Coinciding with more frequent starts, the number of short dispatch cycles is also expected to increase.[13] This magnifies the contribution of variable maintenance costs to the SRMC of the peaking asset.

The peaking machine runs through maintenance stages after a specific number of starts.[14] Each start of the machine entails a cost that is accrued in a future period when the maintenance actually happens. If the machine is started more frequently to generate a certain amount of energy, more frequent maintenance is required during the remaining life of the asset. It also brings forward the schedule of required maintenance. The present value of future maintenance expenditures increases leading to a further increase in the SRMC of supply.

The alternative maximum STEM price is recalculated monthly based on changes in the monthly distillate price. The following regression equation is used to derive the alternative maximum STEM price each month:

> alternative maximum STEM price = non-fuel coefficient + (fuel coefficient multiplied by the Net Ex Terminal distillate fuel cost in $/GJ)

The fuel coefficient for the alternative maximum STEM price is multiplied by the distillate fuel price to estimate the contribution of fuel price to the alternative maximum STEM price. The non-fuel coefficient for the alternative maximum STEM price captures the rest of the cost components, including variable O&M and fuel transport costs. For comparison, Table 3 lists the existing and proposed components of the alternative maximum STEM price.

Table 3. Existing and proposed components of the alternative maximum STEM price

Effective date	Non-fuel coefficient of the alternative maximum STEM price ($/MWh)	Fuel coefficient of the alternative maximum STEM price
1 July 2016 (approved)	84.07	19.311
1 October 2017 (proposed)	227.88	19.256

Each month the alternative maximum STEM price will be determined by substituting the current Net Ex Terminal distillate price into the regression equation. Using the proposed components in Table 3, Jacobs reported the alternative maximum STEM price of $544/MWh based on a projected distillate price of $16.43/GJ for the month of July 2017.[15]

Jacobs' report notes that the increase in the alternative maximum STEM price from last year is primarily driven by the change in the calculation method for variable maintenance

[13] 'Dispatch cycle' refers to the generation of electricity from the start-up to shutdown of a generator.

[14] The maintenance cycle occurs following a specific number of starts or running hours, whichever comes first. However, due to the tendency toward short dispatch cycles occurring more frequently, the number of starts is reached before the number of running hours.

[15] Although AEMO suggested the proposed energy price limits to take effect on 1 October 2017, they did not provide the alternative maximum STEM price based on a projected distillate price for the month of October 2017.

costs and the increase in the number of starts of the highest cost generating works in the SWIS (together leading to $140.5/MWh upward change in the alternative maximum STEM price). The increase in oil price also contributes to the increase in the alternative maximum STEM price, leading to a $55.7/MWh upward change in this price.[16] A summary of the movement in costs is shown in Figure 10 of Jacobs' final report.

4. Implications of the revised method and expected increase in energy price limits

The previous method adopted for the calculation of variable maintenance costs has been applied consistently since the first review of the energy price limits in 2007. Generally, the application of the previous method resulted in the underestimation of variable maintenance costs, and hence, the energy price limits. The implications for the WEM of setting price caps that is too low are:

- insufficient recovery of supply costs in instances when energy market prices reached the energy price limits;
- limiting the volatility of prices in the energy markets. A smaller price volatility reduces the risk premium charged in long-term contracts for the wholesale supply of electricity;
- discouraging investments in generation, particularly peaking generation and electricity storage assets; and
- inaccurate estimation of other variables, costs, or prices determined by the variable maintenance costs.

The aggregate loss due to insufficient recovery of supply costs may have been significant. For instance, from July 2012 to July 2017, 81 trading intervals in the balancing market reached the maximum STEM price.[17] Assuming the market had cleared at a $100/MWh to $200/MWh[18] higher price cap than the set price cap for the 81 intervals, the aggregate cost of supply would have increased by approximately $12 million to $24 million, respectively.[19]

The effect of limited volatility, discouraged generation investments and inaccurate estimation of other variables, costs or prices on market outcomes cannot be measured directly. The relatively low maximum energy price limits provided a hedge to electricity retailers against price volatility in the energy market. A higher price cap in the market can expose retailers to electricity price volatility. Consequently, in the future, demand for hedging products, such as forward and future contracts may increase. The increased price caps will also magnify the uncertainty about future electricity prices, and so the risk premium charged in hedging instruments may escalate.

With increased penetration of intermittent generation in the SWIS, the frequency of market clearing prices hitting the energy price limits may increase. If the maximum energy price

[16] Oil price has grown by 70 per cent since its low point in January 2016.

[17] During the same period, prices in the STEM market never reached the maximum STEM price.

[18] The change in the method for the calculation of variable maintenance costs resulted to an approximate $200/MWh increase in the maximum STEM price estimated this year. The influence of the revision in method was dampened by a reduction in the estimate of maintenance expenditures (from $12.3m to $10m).

[19] The average amount of demand during the 81 trading intervals when balancing prices hit the maximum STEM price was approximately 2,950 MW.

limits are set low, peaking facilities cannot recover their SRMC of supply. Less incentives will be available to generators, including battery storage units that are capable of quickly responding to high electricity demand trading intervals. Investment in such assets may be deferred and existing assets may be deterred from participating in the market.

There is a possibility that market participants have used a similar method for the calculation of variable maintenance costs to estimate their SRMC of supply, which affects supply offer prices in the market. There is also a possibility that the incorrect calculation of such costs has influenced the calculation of other variables determined under the market rules.[20]

5. The ERA's assessment

For the purposes of this decision, as required under clause 2.26.1 of the market rules, the ERA is required to consider whether AEMO's proposed values reflect the application of the method and guiding principles for calculating the energy price limits described in clause 6.20 of the market rules.[21]

5.1. Key parameters

The ERA has reviewed Jacobs' final report and AEMO's proposed energy price limits to take effect from 1 October 2017. The review by Jacobs generally follows the same method for setting the energy price limits as approved by the ERA last year.

As outlined above, the market rules define both the formula for calculating the maximum STEM price and alternative maximum STEM price and the key parameters that must be used. Table 4 sets out the proposed values for the key parameters used in the calculation of the maximum STEM price.

[20] For instance, start-up costs estimated as part of the energy price limits review are used in the calculation of margin values for the provision of spinning reserve.

[21] Consequently the issues related to the methodology, as also raised in the ERA's review of the methodology, are not considered in this decision. In January 2014, the ERA published the Review of the methodology for setting the Maximum Reserve Capacity Price and the energy price limits in the WEM final report, as required under clause 2.26.3 of the market rules. The ERA made a number of findings and recommendations it considered would improve the arrangements for determining the energy price limits. The ERA considers any modifications to the arrangements for determining the energy price limits should be considered as part of the Electricity Market Review.

Table 4. Key parameters used for the calculation of the maximum STEM price

Parameter	Unit	Proposed (to take effect on 1 October 2017)	Approved (took effect on 1 July 2016)
Mean variable O&M	$/MWh	158.93	57.18
Mean heat rate	GJ/MWh	19.238	19.047
Mean fuel cost	$/GJ	6.97	7.57
Loss factor		1.0322	1.0322
Price before risk margin 6.20.7(b)	$/MWh	283.88	195.54
Risk margin added	$/MWh	67.12	44.46
Implied risk margin value*	%	23.6	22.7
Assessed maximum price	$/MWh	351	240

* Based on the model developed, risk margin value added is an output of the calculation rather than an input in determining the energy price limit.

The parameters required to calculate the alternative maximum STEM price are the same as those used for the maximum STEM price, although the heat rate and fuel cost values differ, reflecting the use of distillate rather than gas. Table 5 sets out the proposed values for the key parameters used to calculate the alternative maximum STEM price.

Table 5. Key parameters used for the calculation of the alternative maximum STEM price

Parameter	Unit	Proposed (to take effect on 1 October 2017)	Approved (took effect on 1 July 2016)
Mean variable O&M	$/MWh	158.93	57.18
Mean heat rate	GJ/MWh	19.289	19.098
Mean fuel cost	$/GJ	16.76	13.89
Loss factor		1.0322	1.0322
Before risk margin 6.20.7(b)	$/MWh	467.17	313.12
Risk margin added	$/MWh	76.83	33.88
Implied risk margin value*	%	16.4	10.8
Assessed maximum price	$/MWh	544**	347[22]

* Based on the model developed, risk margin value added is an output of the calculation rather than an input in determining the energy price limit.

** Based on a projected distillate price of $16.43/GJ for the month of July 2017.

[22] Based on distillate price of $13.56/GJ.

5.2. Selection of the highest cost generating works

As required by clauses 6.20.7(a)(i) and 6.20.7(a)(ii) of the market rules, the maximum STEM price and the alternative maximum STEM price are estimated based on the SRMC of the highest cost generating works in the SWIS (fuelled by natural gas and distillate, respectively). Additionally, the market rules require the use of parameters for a '40 MW open cycle gas turbine generating station' in the calculation of the price limits.[23]

Pinjar 40 MW gas turbines[24] and Parkeston aero-derivative gas turbines have consistently had the highest cost for short dispatch periods since the introduction of the energy price limits in the WEM. The Kwinana twin sets were included in the 2011 review. However, Jacobs demonstrated that, due to lower operations and fuel costs, they are very unlikely to have higher dispatch costs than the Pinjar gas turbines for the foreseeable future.

For the review this year, Jacobs assessed the potential of three Mungarra gas turbines (GT1 to GT3) to be considered as the highest generating works in the SWIS. Despite having similar characteristics to Pinjar turbines, historically these machines have been excluded from the analysis of the energy price limits. In the past, Mungarra gas turbines frequently provided voltage support to the Geraldton region. Since the commissioning of the Mid-West Energy Project, Southern Section, in August 2016 they have been operating less frequently. Jacobs notes that under the new operational regime Mungarra gas turbines are suitable candidates for inclusion in the energy price limits analysis. However, the limited historical data under the new regime prohibits an effective assessment of dispatch cycle cost estimations. These machines were excluded from the analysis this year.[25]

In the review of the energy price limits this year, Jacobs considered Pinjar 40 MW units (hereafter referred to as Pinjar units) and the Parkeston aero-derivative gas turbines as the candidates for the highest cost generating units.

Similar to the analysis from last year, Jacobs updated its modelled costs for the candidate machines (i.e. Pinjar units and Parkeston) and confirmed that the Pinjar units continue to be the highest cost generating machines in the SWIS.

5.3. Mean variable O&M

The estimation of variable O&M cost is conducted in three steps.

1. The maintenance expenditures are identified and reviewed.
2. The present value of maintenance expenditures during the life of the asset is calculated. Subsequently, a discounted maintenance cost per start of the machine is calculated.
3. The discounted cost per start is converted to a discounted cost per MWh of electricity generated.

[23] Refer to clause 6.20.7 (b) in the market rules

[24] Pinjar units 1 to 5 and 7 have a capacity of 40 MW. Other Pinjar units (9, 10, and 11) are about 120 MW in size, and hence, are excluded from the analysis.

[25] Jacobs also notes that Mungarra units have similar characteristics to Pinjar units. Consequently, the risk of underestimating the energy price limits, due to the exclusion of Mungarra units, is minimal. It is recommended to include Mungarra units in the next review of energy price limits.

Review of underlying maintenance costs

Jacobs has determined the variable O&M costs for Pinjar units based on available engineering data. The variable components of the operating and maintenance cost included in the SRMC and considered in the determination of energy price limits are the:

i. per start basis cost, which is independent from operation duration and load levels;

ii. per hour of operation cost, which is independent from machine loads; and

iii. per energy generated basis.[26]

The estimated variable O&M cost is based on those O&M costs that are proportional to the number of starts or the duration of operation.[27] Jacobs identifies the maintenance costs for each maintenance stage of the machine throughout a maintenance cycle.

In this year's review, Jacobs reviewed the O&M costs by assessing them against industry practice. It concluded that some of the components of these costs were overestimated. In particular, the costs associated with the reuse, repair, and replacement of machine parts were unreasonably high. The review of O&M costs led to a 19 per cent reduction in the base costs when compared to the cost derived using assumptions made last year.

Jacobs reported that there was no material change in the maintenance regime of the relevant gas turbines and general trends in the industry remain unchanged. Jacobs has updated the O&M costs with an adjustment for foreign exchange movements and a standard CPI cost escalation, which is appropriate for the industry. A key difference to the review from last year is the application of the foreign exchange movements to component parts of O&M costs (comprising 70 per cent of the total O&M cost). The labour component of the O&M costs is not subject to foreign exchange adjustment.

Estimation of discounted cost per start

The ERA conducted a detailed review of the calculation of the variable O&M costs provided by AEMO in its previous report submitted on 15 June 2017. The ERA determined that the method adopted for the estimation of the present value of future maintenance expenditures did not adequately account for the time value of money and risk associated with future maintenance expenditures. Accordingly, AEMO developed a revised method in consultation with the ERA, and also revised some of the underlying assumptions in the analysis. A summary of the ERA's analyses of the revised method is presented below.[28]

Maintenance stages occur after a specific number of starts or running hours, whichever comes first.[29] Therefore, the cost for each start of the machine is accrued in a future period (i.e. when a maintenance stage actually occurs).

[26] Annual O&M costs are not a part of SRMCs for a generating works and, as hence, are excluded from the estimation of energy price limits.

[27] For Pinjar units Jacobs did not identify any significant per energy generated basis variable cost.

[28] A detailed explanation of the identified error and the revised method is provided in the final report provided by AEMO on 15 August 2017 (refer to section 3.4.2). https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/WA_WEM_Consultation_Documents/2017/Price-limits-review/Revised-Jacobs-Draft-Report-Clean.pdf

[29] For details of maintenance stage costs in a full maintenance cycle refer to Table 4 of Jacobs' final report.

Jacobs developed a method to estimate the variable maintenance cost for each start of the machine. The present value of future maintenance expenditures is estimated depending on a discount rate, maintenance cycle length, the current status of the asset in terms of the last maintenance stage performed (a random variable), and the average number of starts per year.[30] This estimation yields an average discounted cost of starts during the remaining life of the asset.

This method is explained briefly via a numerical example. Maintenance stages occur after the stated number of starts with costs listed in the table below,

Table 6. Overhaul costs for industrial gas turbines (December 2017 dollars)

Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul (2017 $)
A	600	1,183,618
B	1200	3,136,397
A	1800	1,183,618
C	2400	4,530,739
	Total cost	$10,034,372

Depending on the number of starts per year, the above maintenance expenditures incur in future periods. Assuming that the machine has just recently been under maintenance type C and a number of starts per annum equal to 82.2, the cash flow profile of future maintenance expenditures are shown in Figure 1.[31]

Figure 1. Maintenance expenditures for a factored start of 82.2 per annum

Year	0	…	7.3	…	14.6	…	21.9	…	29.2
Maintenance			A		B		A		C
Cost			1,183,618		3,136,397		1,183,618		4,530,739

An increase in the frequency of starts can increase the number of required maintenance during the remaining life of the machine and bring those expenditures closer in time. That is, an increase in the frequency of starts increases the present value of future maintenance expenditures. The present value of the cash flow profile shown in Figure 1 is estimated based on a real discount rate of 9 per cent per annum:

$$present\ value\ of\ future\ maintenance\ expenditures = \$2{,}067{,}648$$

The present value of future maintenance expenditures is then divided by the discounted number of starts over the remaining life of the asset to estimate a discounted cost per start. A cost is accrued with each start of the machine. Those costs are spread over future periods and have to be discounted to their present value:[32]

[30] Between 2016 and 2017, the average number of starts per year has increased from 52.9 to 68.5.

[31] The original equipment manufacturer applies a factored starts to estimate the timing of maintenance as opposed to actual starts of the machine. Jacobs uses a factored start of 120 percent of actual start to estimate the maintenance schedule.

[32] A more intuitive alternative to calculate cost per start is to annualise the average discounted cost (in an annuity) and then divide the annual amount by the average number of starts per year.

$$Discounted\ maintenance\ cost\ per\ start = \frac{2{,}067{,}648}{839.58} = \$2{,}462/start$$

The discounted maintenance costs were divided by the total number of starts in a full maintenance cycle, i.e. 2,400 starts.

Jacobs applied a Monte Carlo simulation to account for uncertainties in the number of starts per annum and the maintenance status of the machine, and to derive a distribution for discounted maintenance costs per start. Jacobs reported that the expected discounted cost per start cost using the Monte Carlo sampling method at 82.2 starts per year is now \$4,279/start. This revised value is higher than the values of \$1,512/start provided in the 2016 review and \$1,945/start provided in the previous draft of the 2017 review.

The ERA considers that the revised method for the calculation of the present value of maintenance expenditures is appropriate. The method applied can be enhanced based on the expectations of the remaining life of the highest cost generating works.

As part of the calculation, Jacobs assumed that the Pinjar units have a remaining life of approximately 29 years. Jacobs stated that these types of machines can run for at least two or three full maintenance cycles, depending on the duration of a full maintenance cycle.

However, despite the mechanical possibility of extending the life of the machine, the retirement of such assets can also happen due to economic considerations. The asset is retired when its maintenance cost exceeds the expected present value of future net cash flows.

The shortcoming of the assumption about the remaining life of the asset was also raised by Perth Energy in response to AEMO's second public consultation. Perth Energy noted the age of the Pinjar units and the expectation that Synergy will retire these assets earlier than the assumed remaining life. Perth Energy referred to Synergy's recent announcement about similar Mungarra and West Kalgoorlie machines that will be taken out of service within a few years. Perth Energy stated that the Pinjar machines are not expected to run through another full maintenance cycle and therefore, the maintenance expenditures are overestimated.

Perth Energy also raised an issue with the application of the factored start parameter, used to calculate the effective number of starts of the machine. Based on the recommendations of the manufacturer of the machine, the factored start value is one half of an actual start at low loads. Jacobs used a factored start value of 1.2 instead.

AEMO, in its final submission to the ERA, stated that both issues raised by Perth Energy have a minor impact on the proposed energy price limits and can be addressed in its next review.

The issues about the remaining life of the asset and the value of factored starts are important and the ERA agrees with AEMO's intention to assess these issues and their effect on proposed energy price limits at the next review.

Conversion of per start discounted costs

To determine the energy price limits, all cost types are required to be stated on a per MWh basis. To convert the calculated discounted cost per start of the machine, an estimate of energy generated per start of the machine is required. This item is dependent on the duration of operation and load when the machine is dispatched. The duration of operation and machine load can vary significantly for each dispatch of a machine. Similar to the analysis from previous years, the concept of a dispatch cycle is used to capture such variations in the form of a dispatch cycle distribution. Jacobs uses historical dispatch data to characterise the dispatch cycle distribution of Pinjar units through the following sampled variables:

- number of start per year;
- run times between 0.5 and 6 hours;
- dispatch cycle capacity factor as a function of run time; and
- maximum capacity.

The product of the latter three variables yields the MWh's of electricity generated per start of the machine.

The discounted cost per start (as calculated in the previous step) is then multiplied by run time per dispatch, capacity factor, and maximum capacity to estimate the expected variable O&M costs on a per MWh basis. For the review this year, the expected variable O&M cost is $158.93/MWh.

5.4. Mean heat rate

The market rules stipulate that the mean heat rate used is the mean rate at minimum capacity for a 40 MW open cycle gas turbine generating station.[33]

Consistent with the method approved in prior years Jacobs finds the minimum load position of Pinjar machines from their historical operational data. A normal distribution, with a mean of 19.238 GJ/MWh (19.289 GJ/MWh for the estimation of the alternative maximum STEM price) and standard deviation of 1.642 GJ/MWh, was derived for the heat rate at minimum capacity. When compared to results from last year, the mean and standard deviation of the heat rate at minimum capacity have increased for the Pinjar machines. The primary driver of the increased heat rate is the increase in the number of times when machines are run at their lower operating range.

5.5. Mean fuel cost

The market rules stipulate that the mean fuel cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station.

Gas price

Jacobs uses recent spot market data to forecast gas prices. It also considers expected developments in the gas market in Western Australia including sources of supply, expected demand, export prices, price of substitutes, and correlation with international oil prices.

[33] The use of mean heat rate at minimum capacity is a conservative assumption required by clause 6.20.7(b)(iii). Given that a risk margin is already accounting for uncertainties in the calculation of price limits, the use of a conservative amount for heat rate may result in setting price limits at too high levels.

Consistent with the methodology approved in previous years, the gas price includes both the price at the gas producer's plant gate and the cost of transmission from the plant gate to the delivery point at the power station.

Jacobs uses a standard ARIMA[34] model to develop a forecast for the distribution of monthly maximum spot gas prices in the 2017–18 financial year. The historical monthly maximum spot price of gas, obtained from the gasTrading website, is used to calibrate the ARIMA model. The range of future maximum spot prices is then derived from the ARIMA model. A normal distribution is fitted to the forecasted series to represent the expected probability density curve of spot prices.[35]

The distribution of gas prices is calculated for each month during the 2017–18 financial year. These distributions are combined to form a composite distribution of gas prices for the entire 2017–18 financial year. The mean and standard deviation of the price of gas, based on the composite distribution, are $4.66/GJ and $1.80/GJ, respectively.

In the 2016 review, the prices forecast by the ARIMA model were adjusted upward to account for expected growth in gas prices in the foreseeable future. Those expectations were not realised in the previous year. Based on a review of gas markets in Western Australia and internationally, Jacobs concluded that both the local and global markets for gas are oversupplied and no significant change is expected over the next eighteen months. As a result, the outcomes of the ARIMA model remain unmodified for the current review of the price limits.

Gas transmission costs have been calculated in a manner consistent with the methodology approved in previous years. The gas price has also been capped at the price that would give the same dispatch cycle cost as the prevailing price of distillate. The ERA considers this continued approach to be appropriate for this review.

Jacobs' approach to estimating spot gas prices for use in setting the maximum STEM price is reasonable and it is appropriate to consider the recent spot market data and how further developments may influence the market.

Jacobs has only used spot price data from the gasTrading platform. As set out in Jacobs' report, there are currently three short-term gas trading platforms in WA. These include the gasTrading platform, the Inlet Trading market operated by DBNGP and the gas trading platform operated by Energy Access Services. Of these three platforms, only the spot gas prices in the gasTrading platform are published, which is why Jacobs has only considered these prices.

Jacobs recognises that, ideally, prices from all three platforms should be considered, but states it was not achievable within the review timeframe as a survey of market participants will be required for the non-published prices. This issue has occurred in the past few reviews.

Distillate price

Consistent with previous reviews, Jacobs has used the Singapore gasoil price to estimate the distillate price in deriving the alternative maximum STEM price, as provided in clause

[34] Autoregressive integrated moving average

[35] The use of historical monthly maximum gas prices in developing forecasts for gas price is a conservative assumption, noting that high forecast prices increase the level of price limits.

6.20.3(b) of the market rules. Jacobs conducts a review of the global oil market to form a judgement about short-term changes in the price of distillate.

Jacobs uses a normal distribution with a mean of $16.78/GJ and a standard deviation of $2.88/GJ to represent the short-term uncertainty in distillate prices.

5.6. Loss factor

The market rules stipulate that the loss factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the reference node.

Jacobs used the latest value of loss factor for Pinjar units, as determined by Western Power. For the 2017–18 financial year the loss factor is 1.0322, which is identical to the value used for the Pinjar units last year.

5.7. Risk margin

The market rules stipulate that the 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. The application of the risk margin will adjust the expected maximum energy price upward. Under variations in the variable generation cost, the added margin minimises the likelihood that the highest cost generating works in the market incurs short-run marginal costs that exceed the fixed energy price limits.

Consistent with previous years, Jacobs identified the likely variability in key inputs to the calculation of the energy price limits and modelled the impact that the variability in the key inputs would have on the dispatch cycle cost. Jacobs chose the energy price limits as the 80th percentile of the output price distribution. The risk margin is chosen to be the difference between the mean and the 80th percentile of the output price distribution.

Jacobs acknowledges that through this approach, the risk margin is an output of the calculation rather than an input in determining the energy price limits. The current market rules provide that the risk margin is to be determined first as an input, which feeds into the equation in clause 6.20.7(b) in order to calculate the energy price limits. Jacobs considers the approach it has taken to be industry best practice.

On 2 December 2014, the Independent Market Operator proposed a rule change to amend the definition of the energy price limits and the application of the risk margin. The Independent Market Operator proposed energy price limits to be calculated such that the likelihood of recovering the SRMC of the highest cost generating works at each trading interval is 80 per cent, which reflects the current determination of the risk margin in the energy price limits calculation.[36]

The ERA considers Jacob's approach to calculating the risk margin as an output of the energy price limits calculation to be appropriate. The amendment of the market rules, currently under consideration by the Rule Change Panel,[37] will reflect this preferred approach.

[36] Refer to the standard rule change proposal RC_2014_05, Rule Change Notice and Proposal, pages 8 and 9, https://www.erawa.com.au/cproot/17016/2/Rule%20Change%20Notice%20and%20Proposal.pdf

[37] The draft rule change report is due to be published on 29 December 2017.

5.8. Coefficients for the alternative maximum STEM price

The alternative maximum STEM price is revised monthly according to changes in the Singapore Gasoil (0.5% sulphur) price.

The ERA has determined in previous reviews that it is more appropriate to approve the coefficients for the alternative maximum STEM price, rather than to approve a single revised value.

Jacobs has calculated the coefficients in line with the method approved in previous reviews.

6. Public consultation

AEMO published the first draft report prepared by Jacobs on the Market Website, accompanied by an invitation for submissions. It described how it arrived at the proposed revised values of the maximum STEM price and the alternative maximum STEM price. AEMO also published a notice in the West Australian newspaper on 28 March 2017, requesting submissions from all sectors of the Western Australian energy industry, including end-users. AEMO did not receive any submissions.

Following the queries raised by the ERA, AEMO announced on the Market Website that the method used for the calculation of variable O&M costs will be reviewed. In the meantime, AEMO advised market participants that the existing energy price limits continued to apply.

On 15 August 2017, AEMO published its second draft report prepared by Jacobs for a two-week public consultation. AEMO sought feedback from the stakeholders on the changes to the method and assumptions for the calculation of the variable O&M costs. AEMO received only one submission from Perth Energy.

7. Conclusion

The ERA is satisfied that the values for the energy price limits proposed by AEMO reasonably reflect the application of the method and guiding principles described in clause 6.20 of the market rules and that AEMO has carried out adequate public consultation processes.