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Your ref:
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Mr Greg Watkinson
Chief Executive Officer
Economic Regulation Authority
Level 4, Albert Facey House
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Dear Greg,

**EFFECT OF REVISED PINJAR LOSS FACTOR ON THE ENERGY PRICE LIMITS**

In accordance with clause 6.20.10 of the Wholesale Electricity Market Rules, the IMO submitted its final report for the 2013 Energy Price Limits Review to the Economic Regulation Authority on 16 May 2013. The final report comprised the covering report prepared by the IMO and the final report of its consultant, Sinclair Knight Merz (SKM MMA).

The IMO noted in its report that SKM MMA had used the current (2012/13 Financial Year) Loss Factor for Pinjar in its calculation of the proposed Energy Price Limits, as the Loss Factor for the 2013/14 Financial Year was not yet available. The IMO considered that the Energy Price Limits proposed by SKM MMA in its Final Report should be adjusted to reflect any change from the current Pinjar Loss Factor (1.0295) to the revised Loss Factor for the 2013/14 Financial Year.

The Loss Factors for the 2013/14 Financial Year were published on the Market Web Site on 5 June 2013. The revised Loss Factor for Pinjar is 1.0312.

Accordingly, the proposed final revised values for the Energy Price Limits are:

- Maximum STEM Price: $305/MWh ($305.37 * 1.0295 / 1.0312 , rounded to the nearest dollar); and
- Alternative Maximum STEM Price:
    - Non-Fuel Coefficient: 67.33 (67.44 * 1.0295 / 1.0312, rounded to two decimal places); and
    - Fuel Coefficient: 19.719 (19.752 * 1.0295 / 1.0312, rounded to three decimal places).

Assuming a distillate price of $21.65/GJ, the proposed Alternative Maximuim STEM Price would be $494/MWh.

If you have any queries in relation to the review or the revised Loss Factor, please do not hesitate to contact me.

Yours sincerely

ALLAN DAWSON
**CHIEF EXECUTIVE OFFICER**

7 June 2013

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Mr Greg Watkinson
Chief Executive Officer
Economic Regulation Authority
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PERTH WA 6000

Dear Greg,

**SUBMISSION UNDER CLAUSE 6.20.10**

In accordance with clause 6.20.10 of the Wholesale Electricity Market Rules (Market Rules), the IMO submits its final report for the 2013 Energy Price Limits Review. The final report comprises the covering report prepared by the IMO and the final report of its consultant, Sinclair Knight Merz (SKM MMA). Please note that the IMO received one submission from Community Electricity during the public consultation period, which supported the Draft Report and raised no issues.

Under the Market Rules, Western Power is required to provide the IMO with revised Loss Factors for the 2013/14 Financial Year by 1 June 2013. As these Loss Factors are not yet available, SKM MMA has used the current (2012/13 Financial Year) Loss Factor for Pinjar in its calculation of the proposed Energy Price Limits.

The IMO considers that the Energy Price Limits proposed by SKM MMA in its Final Report should be adjusted to reflect any change from the current Pinjar Loss Factor (1.0295) to the Loss Factor determined by Western Power for the 2013/14 Financial Year, once the latter value becomes available.

The IMO notes that a similar adjustment was made to the prices proposed by SKM MMA in its Final Report for the 2012 Review. Based upon historical experience and preliminary advice from Western Power, it is expected that the impact on the Energy Price Limits will be minimal.

Accordingly, the IMO proposes the following final revised values for the Energy Price Limits (note "PLF_Rev" is the revised Pinjar Loss Factor for the 2013/14 Financial Year):

- Maximum STEM Price: ($305.37 * 1.0295 / PLF_Rev) / MWh (rounded to the nearest dollar); and
- Alternative Maximum STEM Price:

- Non-Fuel Coefficient: 67.44 * 1.0295 / PLF_Rev (rounded to two decimal places); and
- Fuel Coefficient: 19.752 * 1.0295 / PLF_Rev (rounded to three decimal places).

Assuming no change to the Pinjar Loss Factor the proposed values would be:

- $305/MWh for the Maximum STEM Price (a decrease from the current price of $323/MWh); and
- $495/MWh for the Alternative Maximum STEM Price, assuming a distillate price of $21.65/GJ (a decrease from the currently approved price of $509/MWh for this distillate price).

The corresponding price components for the Alternative Maximum STEM Price would be:

- $67.44/MWh + 19.752 multiplied by the delivered distillate fuel cost in $/GJ.

The IMO proposes that the revised Energy Price Limits take effect from 8:00 AM on 1 July 2013. If approved by the ERA the new values will be posted on the IMO web site in advance of that date to allow Market Participants to update their standing bids on the basis of the revised Energy Price Limits (clause 6.20.11(b) of the Market Rules). The IMO plans to publish the values on its web site on 24 June 2013.

In order to meet this timetable, the IMO requests the outcome of the ERA's decision by 21 June 2013 (pursuant to clause 2.26.1(b) of the Market Rules).

If you have any queries in relation to the review, please do not hesitate to contact me.

Yours sincerely

ALLAN DAWSON
**CHIEF EXECUTIVE OFFICER**

16 May 2013

INDEPENDENT
MARKET
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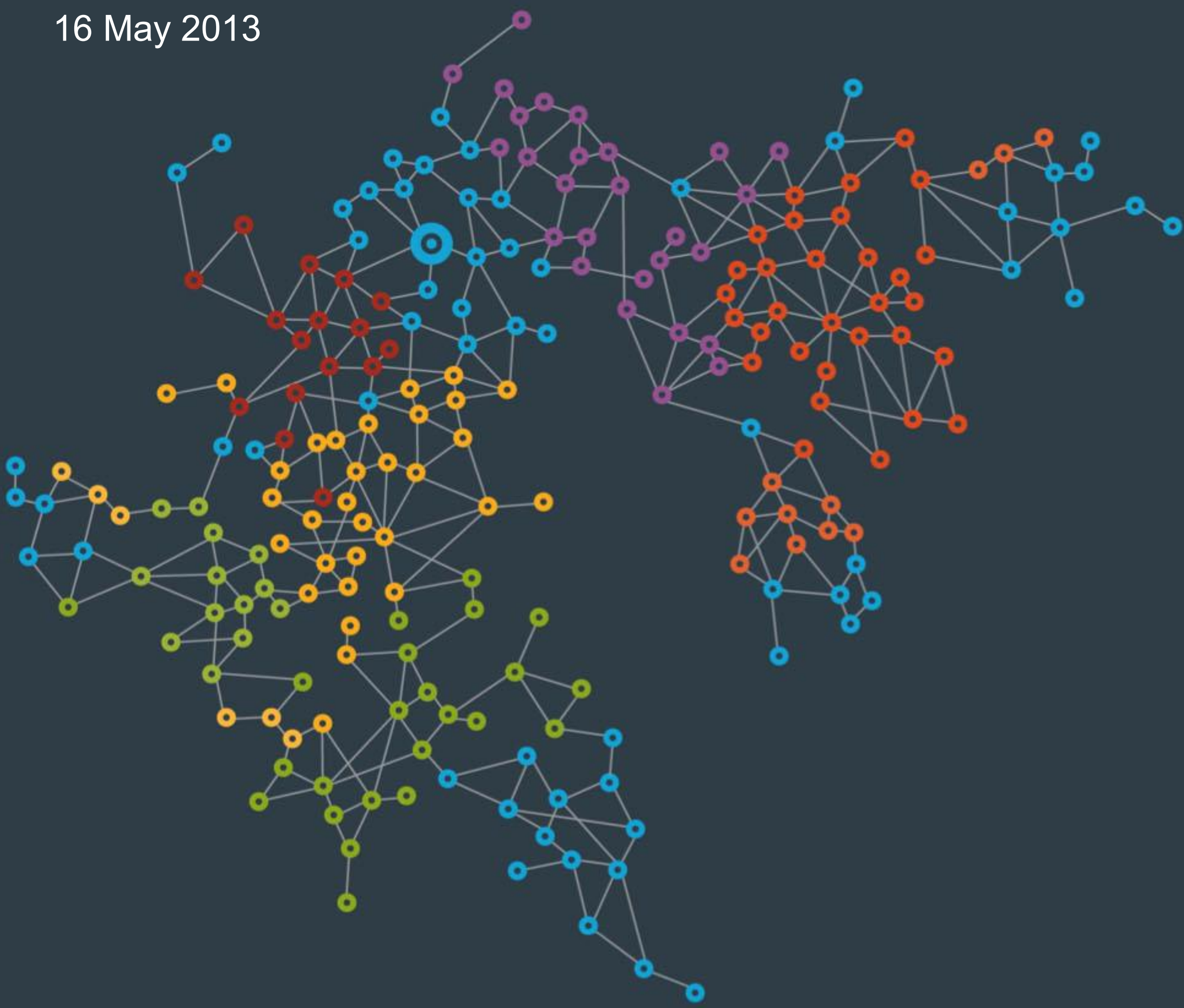
# Independent Market Operator

## Final Report

## 2013 Review of the Energy Price Limits for the Wholesale Electricity Market

16 May 2013



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# 1. Background

Clause 6.20.6 of the Wholesale Electricity Market (WEM) Rules (Market Rules) requires the Independent Market Operator (IMO) to annually review the appropriateness of the values of the Energy Price Limits. In conducting the review, the IMO may propose revised values for the Maximum Short Term Energy Market (STEM) Price and the Alternative Maximum STEM Price. The IMO must calculate the revised values using the methodology set out in clause 6.20.7 of the Market Rules.

The IMO engaged Sinclair Knight Merz (SKM MMA), an independent consultant, to assist the IMO in undertaking its annual review of the Energy Price Limits for 2013. SKM MMA was also engaged in 2012 to undertake this task.

The 2013 review included:

- determining whether the cost assumptions and probability levels adopted in the modelling are still appropriate;
- revising the maximum prices by conducting an analysis of the relevant costs; and
- the preparation of a Draft Report and Final Report.

The review of the Energy Price Limits is now complete. The Final Report required under clause 6.20.10 of the Market Rules comprises this report and SKM MMA's Final Report. A copy of SKM MMA's Final Report is available on the IMO website: IMO - 2013 Energy Price Limits Review.

# 2. Summary of the IMO's Draft Report

Two price caps were reviewed, the Maximum STEM Price, which applies when gas is used by the highest cost peaking plant, and the Alternative Maximum STEM Price, which applies when liquid fuel is required to be used.

The 2013 review has:

- continued with the methodology for setting the Energy Price Limits applied in 2012;
- updated the impact of the carbon price on dispatch cycle cost so that the Energy Price Limits reflect the legislated carbon price of $24.15/tCO_2e$ from 1 July 2013;
- updated the operating and maintenance (O&M) costs for operating 40 MW gas turbines for both the industrial and aero derivative types by escalating the previously advised costs, as no further information was obtainable;
- corrected the start-up fuel consumption calculation for liquid fuel;
- continued the methodology for the modelling of the gas supply having regard to the recommendations made by ACIL Tasman in its final report for the 2013 Review of Gas Prices in the Wholesale Electricity Market (WEM)[1], and in particular:
    - developed the gas pricing based on parameters that were deemed applicable to the spot purchase and transport of gas for peaking purposes;

[1] IMO - 2013 Review of Gas Prices in the WEM

- defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
- used a combination of three lognormal distributions of gas commodity cost between $2/GJ and $24/GJ[2] with an 80% confidence range of $4.98/GJ to $11.54/GJ, a mean value of $7.94/GJ and a most probable value of $6.60/GJ to match the composite distribution provided by ACIL Tasman; and
- used a lognormal distribution of spot gas transport cost to the Perth area between $1.00/GJ and $3.00/GJ with an 80% confidence range between $1.46/GJ and $2.15/GJ, a mean value of $1.795/GJ and a most likely value of $1.735/GJ;

- using the latest market observations since January 2009, examined in detail the possible range of uncertainty in the analysis of the costs, including the effect of the observed distribution of run times and dispatch and the impact on average heat rate;
- concluded that the frequency of starts of Pinjar has halved from September 2012 due to the commissioning of the new Kwinana high efficiency gas turbines, and used the frequency of starts between January 2009 and August 2012 divided by two to represent Pinjar's starting frequency from 1 July 2013;
- continued the previous treatment of start up costs and the cost uncertainty. The recommended price is set to cover 80% of possible outcomes with run times of between 0.5 and 6 hours; and
- recommended a set of new values in accordance with the Market Rules.

The proposed revised values presented in the Draft Report were $305/MWh for the Maximum STEM Price and, assuming a distillate price of $21.65, $495/MWh for the Alternative Maximum STEM Price. The corresponding price components for the Alternative Maximum STEM Price were:

$67.44/MWh + 19.752 multiplied by the delivered distillate fuel cost in $/GJ.

# 3. Public Consultation Process

As required by the Market Rules, on 19 March 2013 the IMO published a Draft Report on the IMO website proposing the revised values for the Energy Price Limits. The IMO published a notice in the West Australian newspaper on this day, requesting submissions on the Draft Report from all sectors of the Western Australian energy industry, including end-users. The consultation period was six weeks in length and closed on 3 May 2013.

The IMO received one submission from Community Electricity during the public consultation period, which supported the Draft Report and raised no issues.

## 3.1 Public Workshop

The IMO invited interested parties to participate in a public workshop on the Energy Price Limits Draft Report, to be held on 11 April 2013. Only one person responded to the IMO's invitation, and when contacted this person had no specific issues or questions to discuss and did not consider that the workshop should be held on his account. On this basis the workshop was cancelled.

[2] Note that the maximum gas price was simulated up to a break-even price with the use of distillate in the generation plant assuming dual fuel capability.

# 4. Changes from the Draft Report

## 4.1 Summary of Changes in SKM MMA's Final Report

The proposed values for the Energy Price Limits in SKM MMA's Final Report are unchanged from the values proposed in the Draft Report. A small number of minor clarifications were made to improve the integrity of the report.

## 4.2 Adjustments to Reflect 2013/14 Loss Factors

Under the Market Rules, Western Power is required to provide the IMO with revised Loss Factors for the 2013/14 Financial Year by 1 June 2013. As these Loss Factors are not yet available, SKM MMA has used the current (2012/13 Financial Year) Loss Factor for Pinjar in its calculation of the proposed Energy Price Limits.

The IMO considers that the Energy Price Limits proposed by SKM MMA in its Final Report should be adjusted to reflect any change from the current Pinjar Loss Factor (1.0295) to the Loss Factor determined by Western Power for the 2013/14 Financial Year, once the latter value becomes available.

The IMO notes that a similar adjustment was made to the prices proposed by SKM MMA in its Final Report for the 2012 Review. Based upon historical experience and preliminary advice from Western Power, it is expected that the impact on the Energy Price Limits will be minimal.

Consistent with this adjustment, the IMO proposes the following amendments to the parameters provided in SKM MMA's Final Report to meet the requirements of clause 6.20.7(b) of the Market Rules:

- Loss Factor (clause 6.20.7(b)(v)) should be updated to reflect the revised Pinjar Loss Factor; and
- Risk Margin (clause 6.20.7(b)(i)) should be calculated in accordance with the formula prescribed in clause 6.20.7(b), using the revised Loss Factor and the Variable O&M, Heat Rate and Fuel Cost values proposed by SKM MMA.

# 5. CONCLUSIONS

The IMO proposes the following final revised values for the Energy Price Limits (note "PLF_Rev" is the revised Pinjar Loss Factor for the 2013/14 Financial Year):

- Maximum STEM Price: ($305.37 * 1.0295 / PLF_Rev) / MWh (rounded to the nearest dollar);
- Alternative Maximum STEM Price:
  - Non-Fuel Coefficient: 67.44 * 1.0295 / PLF_Rev (rounded to two decimal places); and
  - Fuel Coefficient: 19.752 * 1.0295 / PLF_Rev (rounded to three decimal places).

Assuming no change to the Pinjar Loss Factor the proposed values would be:

- $305/MWh for the Maximum STEM Price (a decrease from the current price of $323/MWh); and

- $495/MWh for the Alternative Maximum STEM Price, assuming a distillate price of $21.65/GJ (a decrease from the currently approved price of $509/MWh for this distillate price).

The IMO proposes that the revised Energy Price Limits take effect on 1 July 2013. The new values will be posted on the IMO website in advance of that date to allow Market Participants to update their standing bids on the basis of the revised Energy Price Limits.

In order to meet this timetable, the Economic Regulation Authority's approval is sought by 21 June 2013. Once the approval is granted, the new values for Energy Price Limits will take effect from the date specified in the notice posted by the IMO on its website.

A summary of the input parameters and key outcomes of the Energy Price Limit reviews for each year since 2007 is available in Appendix 1 of this report.

### 5.1 Potential Areas for Review of the Market Rules

The IMO is currently considering a number of potential amendments to the Market Rules relating to the determination of the Energy Price Limits. These include:

- amendments to more transparently describe the current probabilistic methodology used for the Energy Price Limit reviews;
- the suggestions for streamlining the annual review process for the Maximum STEM Price and the Alternative Maximum STEM Price raised by Synergy in its submission for the 2011 Review of the Energy Price Limits;
- an extension of the IMO's powers to request actual operational data from Market Participants, to allow the request of operational data (on a confidential basis) to provide more accurate input to the Energy Price Limits modelling process;
- replacement of the Singapore Gas Oil (0.5% sulphur) price used to calculate the Alternative Maximum STEM Price with the Singapore Gas Oil 10 ppm price, on the basis that the latter price is more relevant to distillate used for power generation in Western Australia;
- amendments to the timing of annual CPI adjustments to the Alternative Maximum STEM Price;
- amendments to allow the IMO to propose amendments to the Energy Price Limits outside of the annual cycle in response to significant changes, e.g. if the Clean Energy Future scheme was repealed; and
- possible removal of the lower price limit from the Market Rules (identified as an issue during the development of the Market Rules Evolution Plan in 2009).

The IMO notes that the Market Rules require the ERA to review the methodology for setting the Energy Price Limits no later than the fifth anniversary of the first Reserve Capacity Cycle (October 2013). This review must include an examination of the parameters and methodology in clause 6.20 for recalculating the Energy Price Limits (clause 2.26.3(g)) and the performance of the Reserve Capacity Auctions, STEM Auctions and Balancing in meeting the Wholesale Market Objectives. The IMO looks forward to working with the ERA to ensure the optimal alignment of any amendments to the Market Rules with the ERA's review process.

## Appendix 1: Input parameters and key outcomes of the 2007 - 2013 reviews

A comparison between the input parameters and key outcomes in the 2007- 2013 reviews is presented in Table 1 and 2. A summary of the monthly changes to the Alternative Maximum STEM Price is presented in Table 3.

**Table 1: Input parameters and key outcomes of the 2007 - 2013 reviews**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| Heat rate | Based on estimate of varying heat rate over a dispatch cycle | Fixed at the heat rate at minimum operating capacity | Fixed at the heat rate at minimum operating capacity | Fixed at the heat rate at minimum operating capacity | Fixed at the heat rate at minimum operating capacity | Fixed at the heat rate at minimum operating capacity | Fixed at the heat rate at minimum operating capacity |
| Industrial type | | | | | | | |
| Gas* | 18.1 to 13.1 GJ/MWh | 18.1 GJ/MWh | 18.1 GJ/MWh | 20.1 GJ/MWh | 20.1 GJ/MWh | 18.6 GJ/MWh | 18.6 GJ/MWh |
| Distillate* | 19.0 to13.8 GJ/MWh | 18.2 GJ/MWh | 18.2 GJ/MWh | 20.1 GJ/MWh | 20.1 GJ/MWh | 18.6 GJ/MWh | 18.7 GJ/MWh |
| Aero derivative | | | | | | | |
| Gas* | 15.7 to 10.7 GJ/MWh | 15.7 GJ/MWh | 15.7 GJ/MWh | 17.8 GJ/MWh | 17.8 GJ/MWh | 13.4 GJ/MWh | 13.4 GJ/MWh |
| Distillate* | 16.5 to 15.7 GJ/MWh | 15.7 GJ/MWh | 15.7 GJ/MWh | 17.8 GJ/MWh | 17.8 GJ/MWh | 13.4 GJ/MWh | 13.4 GJ/MWh |
| Fuel Cost | | | | | | | |

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| Gas contract price | $6/GJ (4.50-7.50) | $8/GJ (6.00-10.00) | $8/GJ (6.00-10.00) | $8/GJ (5.00-12.00) | $6.50/GJ (4.60-12.20)[3] | $6.48/GJ (5.33-12.17) | $6.60/GJ (4.98-11.54) |
| Gas Emission Cost | | | | | | | |
| South West | | | | | | $1.27/GJ | $1.34/GJ |
| Goldfields | | | | | | $1.26/GJ | $1.33/GJ |
| Gas Transport | | | | | | | |
| South West | $1.40/GJ | $1.45/GJ | $1.47/GJ | $1.78/GJ | $1.77/GJ | $1.82/GJ | $1.74/GJ |
| Goldfields | $3.17/GJ | $3.26/GJ | $3.35/GJ | $4.15/GJ | $5.00/GJ | $5.67/GJ | $5.91/GJ |
| Load factor range | 70% (50% to 90 %) | unchanged | 75% (70-85%) | 94.4% (80-100%) | 95.0% (80-98%) | 95.0% (80-98%) | 95.0% (80-98%) |
| Distillate price** | $24/GJ | $32/GJ | $18/GJ | $19/GJ | $23/GJ | $24/GJ | $22/GJ |
| Distillate Emission Cost | | | | | | $1.72/GJ | $1.68/GJ |
| O&M costs | | | | | | | |
| Industrial type | $8.07/MWh | $9.27/MWh | $14.04/MWh | $14.31/MWh | $17.57/MWh | $14.49/MWh | $10.02/MWh |
| Aero derivative | $180/hr (maintenance only) | $210/hr (maintenance only) | $196/hr (time based discounted cost) | $201/hr (time based discounted cost) | $195/hr (time based discounted cost) | $194/hr (time based discounted cost) | $199/hr (time based discounted cost) |

3 Based on the most probable value for spot gas and the 80% confidence range. Note that gas contract prices prior to 2010 have been presented as mean values.

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| Starts per year (average) | | | | | | | |
| Industrial type | 160 | 145 | 160 | 157 | 157.7 | 160.8 | 76.4 |
| Aero derivative | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour) | Taken into account in a different way (1 start equivalent to only 1 running hour |

Note: * Rounded to 1 decimal places.

** Rounded to 0 decimal place

**Table 2: Key Outcomes from the 2007 - 2013 reviews**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013[4] |
|---|---|---|---|---|---|---|---|
| Non-Liquid | | | | | | | |
| Maximum STEM Price | $206/MWh | $286/MWh | $276/MWh | $336/MWh | $314/MWh | $323/MWh | 305/MW |
| Annual % Change[5] | 34.44% | 38.83% | -3.50% | 21.74% | -6.55% | 2.87% | -5.57% |
| Probability level | 80% | 80% | 80% | 80% | 76% | 80% | 80% |
| Margin over Expected Value | 15.1% | 13.9% | 14.0% | 20.0% | 16.3% | 18.9% | 22.1%[6] |
| Liquid | | | | | | | |
| Alternative Maximum STEM Price | $498/MWh (see monthly changes in the table below) | $763/MWh | $469/MWh | $446/MWh | $533/MWh | $547/MWh | $495/MWh |
| Annual % Change | 3.75% | 53.21% | -38.53% | -4.90% | 19.51% | 2.63% | -9.51% |
| Alternative Maximum STEM Price for $21.65/GJ distillate price | $458/MWh | $496/MWh | $533/MWh | $506/MWh | $514/MWh | $509/MWh | $495/MWh |
| Probability level | 90% | 90% | 90% | 80% | 80% | 80% | 80% |
| Margin over Expected Value | 14.5% | 10.7% | 19.3% | 6.2% | 6.2% | 7.8% | 8.4%[7] |

[4] Note values assume no change to the Pinjar Loss Factor for the 2013/14 Financial Year.
[5] Based on the initially published prices (21 September 2006) of $153.73 (Maximum STEM Price) and $480.00 (Alternative Maximum STEM Price).
[6] Note that the Risk Margin as specified in clause 6.20.7(b)(i) is 22.1%.
[7] Note that the Risk Margin as specified in clause 6.20.7(b)(i) is 8.4%.

**Table 3: Monthly Changes to the Alternative Maximum STEM Price ($/MWh)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| January | | 532 | 592 | 454 | 416 | 546 | 535 |
| February | | 550 | 512 | 458 | 418 | 552 | 525 |
| March | | 569 | 463 | 464 | 435 | 559 | 515 |
| April | | 573 | 423 | 466 | 476 | 558 | 525 |
| May | | 593 | 411 | 473 | 520 | 564 | 523 |
| June | | 632 | 405 | 486 | 546 | 571 | |
| July | | 692 | 416 | 496 | 549 | 547 | |
| August | | 743 | 439 | 501 | 536 | 528 | |
| September | | 779 | 450 | 498 | 522 | 510 | |
| October | | 763 | 469 | 446 | 524 | 510 | |
| November | 498 | 722 | 459 | 438 | 533 | 528 | |
| December | 498 | 653 | 458 | 426 | 534 | 540 | |

INDEPENDENT
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# ENERGY PRICE LIMITS FOR THE WHOLESALE ELECTRICITY MARKET IN WESTERN AUSTRALIA FROM JULY 2013

- Final 1.0
- 8 May 2013

# ENERGY PRICE LIMITS FOR THE WHOLESALE ELECTRICITY MARKET IN WESTERN AUSTRALIA FROM JULY 2013

- Final 1.0
- 8 May 2013


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# EXECUTIVE SUMMARY

Once a year, the Independent Market Operator (IMO) is required to review the Energy Price Limits in the Wholesale Electricity Market. Sinclair Knight Merz (SKM MMA) was engaged by the IMO to conduct the 2013 review for the year commencing 1 July 2013. This assignment was conducted in a similar fashion to that conducted by SKM MMA in 2012.

For the 2013 review, SKM MMA has:

- Continued with the basis for setting the Energy Price Limits as applied in 2012.
- Updated the impact of the carbon price on dispatch cycle cost so that the Energy Price Limits reflect the legislated carbon price of \$24.15/t$CO_2$e from 1 July 2013.
- Updated the O&M costs for operating 40 MW gas turbines for both the industrial and aero derivative types by escalating the previously advised costs as no further information was obtainable.
- Amended the start-up fuel consumption calculation for liquid fuel. Previously a 5% increase had been applied to start-up fuel consumption as measured by Higher Heating Value. It was identified that the 5% should have been applied to the Lower Heating Value which is equivalent to a 0.27% increase in fuel consumption, consistent with that used for the average heat rates at maximum and minimum capacity. The amendment has no impact on the assessed Maximum STEM Price and very little impact on the assessed Alternative Maximum STEM Price. Average heat rates at maximum and minimum capacity were not reviewed.
- Continued the methodology for the modelling of the gas supply having regard to the recommendations made by ACIL Tasman in its 2013 Final Report[1], and in particular:
  - Developed the gas pricing based on parameters that were deemed applicable to the spot purchase and transport of gas for peaking purposes.
  - Defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
  - Used a combination of three lognormal distributions of gas commodity cost between \$2/GJ and \$24/GJ/[2] with an 80% confidence range of \$4.98/GJ to

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[1] Gas Prices in Western Australia, 2013/14 Review of inputs to the Wholesale Electricity Market, Final Report prepared for the Independent Market Operator by ACIL Tasman, February 2013

[2] Note that the maximum gas price was simulated up to a break-even price with the use of distillate in the generation plant assuming dual fuel capability.

$11.54/GJ, a mean value of $7.94/GJ and a most probable value of $6.60/GJ to match the composite distribution provided by ACIL Tasman[3];

  - Used a lognormal distribution of spot gas transport cost to the Perth area between $1.00/GJ and $3.00/GJ with an 80% confidence range between $1.46/GJ and $2.15/GJ, a mean value of $1.795/GJ and a most likely value of $1.735/GJ.

- Using the latest market observations since January 2009, examined in detail the possible range of uncertainty in the analysis of the costs, including the effect of the observed distribution of run times and dispatch and the impact on average heat rate.
- Concluded that the frequency of starts of Pinjar has halved from September 2012 due to the commissioning of the new Kwinana high efficiency gas turbines, and used the frequency of starts between January 2009 and August 2012 divided by 2.0 to represent Pinjar's starting frequency from 1 July 2013.
- Continued the previous treatment of start-up costs and the cost uncertainty. The recommended price is set to cover 80% of possible outcomes with run times of between 0.5 and 6 hours.

Exec Table 1 shows the calculation of the Energy Price Limits in accordance with the structure defined in clause 6.20.7(b) of the Market Rules.

- **Exec Table 1 Summary Parameters defined in Clause 6.20.7 (b)**

| Component | Units | Maximum STEM Price | Alternative Maximum STEM Price |
|---|---|---|---|
| Mean Variable O&M | $/MWh | $32.04 | $32.04 |
| Mean Heat Rate | GJ/MWh | 18.735 | 18.774 |
| Mean Fuel Cost (Including emissions cost) | $/GJ | $12.02 | $23.33 |
| Loss Factor | | 1.0295 | 1.0295 |
| Before Risk Margin 6.20.7(b) [4] | $/MWh | $249.86 | $456.57 |
| Risk Margin added | $/MWh | $55.14 | $38.43 |
| Risk Margin Value | % | 22.1% | 8.4% |
| Assessed Maximum Price | $/MWh | $305.00 | $495.00 |

[3] Note that the mean of the distribution is greater than the most likely value (mode) due to the asymmetry of the lognormal distribution. The mode of the single fitted lognormal distribution stated by ACIL Tasman was $6.80/GJ. The SKM fitted gas price distribution was a closer fit to the composite distribution developed by ACIL Tasman than the fitted distribution proposed by ACIL Tasman and therefore has a slightly different mode.

[4] Mean values have been rounded to the values shown in the Table for the purpose of this calculation.

Exec Table 2 summarises the prices that have applied since October 2010 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar which is consistent with previous practice.

- **Exec Table 2 Summary of price cap analysis**

| No. | Method | Maximum STEM Price ($/MWh) | Alternative Maximum STEM Price ($/MWh) | Comment |
|---|---|---|---|---|
| 1 | Published Prices from 1 October 2010 | $336 | $446 | From IMO website. |
| 2 | Published Prices from 1 October 2011 | $314 | $524 | From IMO website. |
| 3 | Published Prices from 1 July 2012 | $323 | $547 | From IMO website. |
| 4 | Published Prices from 1 May 2013 | $323 | $523 | From IMO website[5] |
| 5 | Proposed prices to apply from 1 July 2013 | $305 | $495 | Based on $21.65/GJ for distillate. |
| 6 | Probability level as Risk Margin basis | 80% | 80% | |

Notes: (1) As required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2013 based on a projected delivered wholesale distillate price of $1.217/litre excluding GST to Pinjar.

(2) In row 6, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

The recommended values are $305/MWh for the Maximum STEM Price and $495/MWh for the Alternative Maximum STEM Price at $21.65/GJ distillate price.

The corresponding price components for the Alternative Maximum STEM Price are:

$67.44/MWh + 19.752 multiplied by the delivered distillate fuel cost in $/GJ.

It has been noted that clause 6.20.3(b)(i)(1) of the Market Rules specifies adjustment of the Alternative Maximum STEM Price according to the 0.5% sulphur Gas Oil price whereas the

[5] http://www.imowa.com.au/market-data-pricelimits accessed 8 May 2013

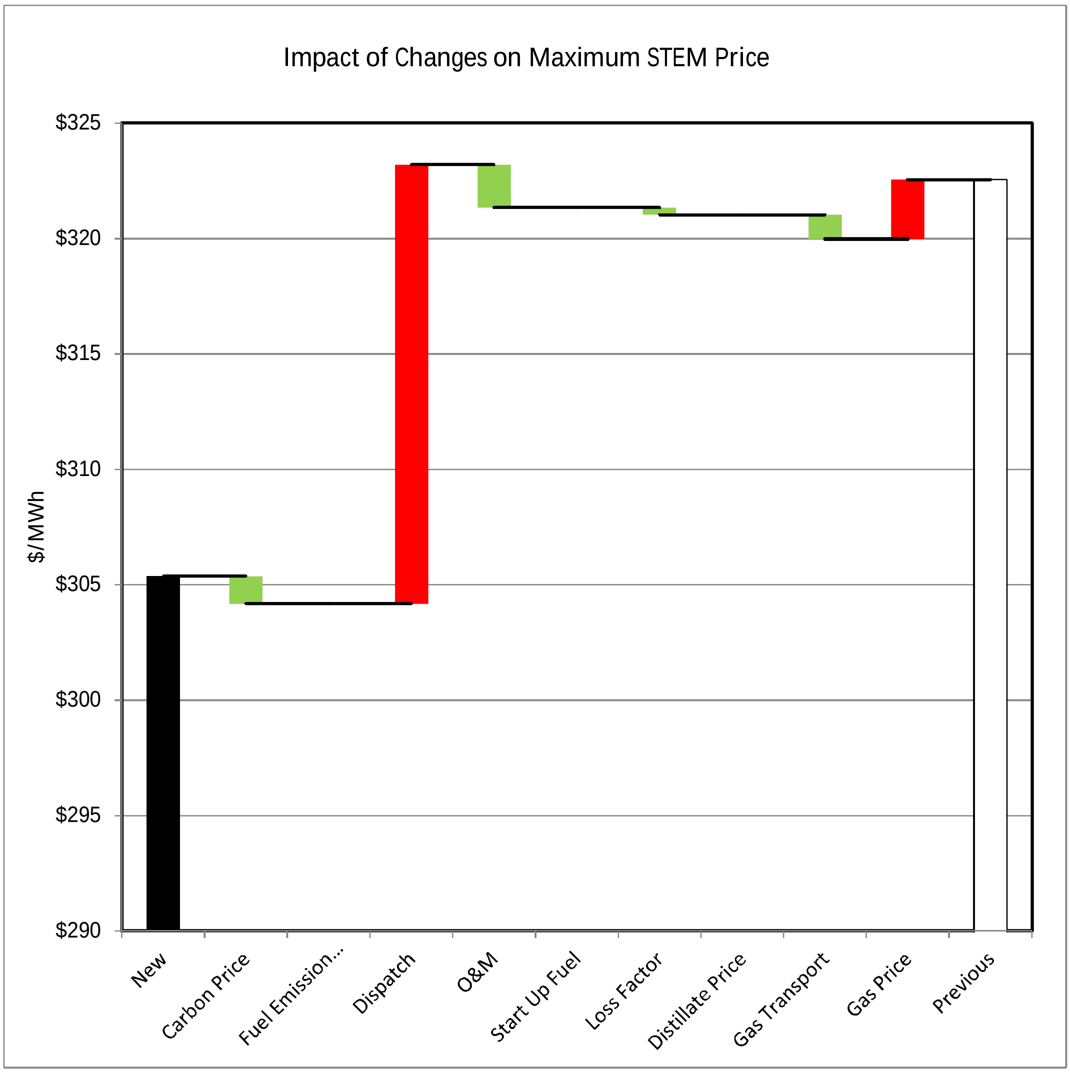
production of distillate for power generation in the WA Market is based on 10 ppm impurity distillate (10 ppm Gas Oil). Consideration should be given to amend the Market Rules to make the price adjustment according to the 10 ppm price. SKM MMA notes this has no influence on the calculation of the components of the Alternative Maximum STEM Price in this report.

The decrease in the Maximum STEM Price since last year's assessment has been primarily due to the reduced number of starts per year for the Pinjar machines. The cost per start has reduced by 36% due to the reduced frequency of starts. This flows through to the variable O&M term in the dispatch cycle cost calculation. The reduced start frequency for Pinjar reduces the present value start cost which results in a lower assessed O&M cost per MWh of dispatch.

The other changes in operating costs and fuel costs have had a slight positive impact on the Maximum STEM Price, of $1.90/MWh[6]. The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Exec Figure 1.

[6] Rounded to the nearest 10c to avoid implying high precision. Actual unrounded value was $1.852. Values in Table 5-3 are rounded.

■ **Exec Figure 1 Impact of factors on the change in the Maximum STEM Price since 2012**

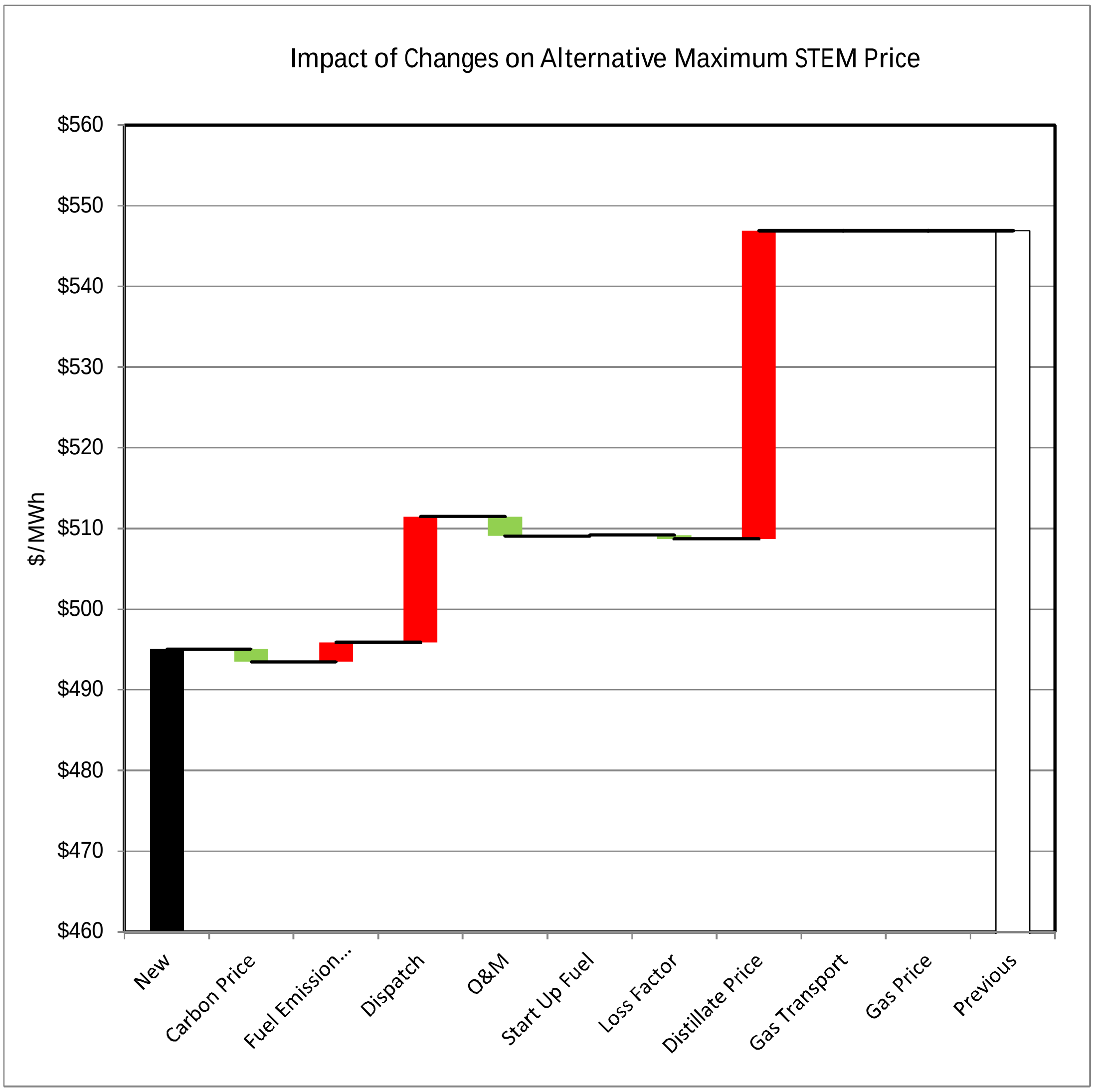



The decrease in the Alternative Maximum STEM Price is primarily due to the decrease in distillate price and the reduced operation of Pinjar as shown in Exec Figure 2. With a constant distillate price, there would still be a decrease in the Alternative Maximum STEM Price due to the reduced operating costs for Pinjar, of $13.60/MWh.

It is recommended that clause 6.20.7 be reformulated to describe more clearly the use of probability distributions and a choice of a percentile value to derive the Energy Price Limits rather than defining a Risk Margin and adding it to the expected value of the combined distribution of average dispatch cycle cost, or to a function of mean values.

SINCLAIR KNIGHT MERZ SKM | M | M | A |

- **Exec Figure 2 Impact of factors on the change in the Alternative Maximum STEM Price since 2012**



# DEFINITIONS

To assist the reader this section explains some of the terminology used in the Report.

| Term | Explanation |
|---|---|
| Dispatch cycle cost | This term is used to describe the parameter calculated to determine the Energy Price Limits. It is the total cost of dispatch of a start-up and shut-down cycle of a peaking gas turbine divided by the amount of electrical energy in MWh generated during the dispatch cycle. |
| Break-even gas price | In simulating the gas price distribution, the delivered gas price was reduced if necessary to make the sampled value of the dispatch cycle cost equal to the dispatch cycle cost for running on distillate, allowing for the impact on relative operating costs and thermal efficiency on both fuels. It was not based on the equivalent heat content of distillate alone. |
| Carbon price | The federal government has legislated to introduce a carbon pricing mechanism from 1 July 2012 with an initial carbon price of \$23/t$CO_2$e and a price from 1 July 2013 of \$24.15/ t$CO_2$e. This carbon price has an impact on the cost of production through the purchase cost of emission permits. |
| Dispatch cycle | The process of starting a generating plant, synchronising it to the electricity system, loading it up to minimum load as quickly as possible, changing its loading between minimum and maximum levels to meet system loading requirements, running it down to minimum load and then to zero for shutdown. |
| Energy Price Limits | The Maximum STEM Price and the Alternative Maximum STEM Price as specified in the Market Rules. |
| Margin | The difference between the price caps as set by the IMO and the expected value of the highest short run costs of peaking power. |
| Market dispatch cycle cost method | A method for calculating the fuel consumption over a dispatch period of a peaking gas turbine that represents various levels of loading consistent with a specified capacity factor. This is an alternative method to specifying a particular heat rate basis irrespective of dispatch conditions. |
| Market Rules | The rules used to conduct the operation of the Western Australian Wholesale Electricity Market (WEM) as gazetted and amended. The current version of the rules was issued on 1 February 2013 and may be found at http://www.imowa.com.au/market_rules.htm. |
| Risk Margin | The difference between the price caps as set by the IMO and a function of the expected values of variable O&M costs, heat rate and fuel cost as specified in the Market Rules clause 6.20.7(b). The Risk Margin is intended to allow for the uncertainty faced by the IMO in setting the price caps, or (in the case of the Alternative Maximum STEM price) its fuel and non-fuel price components. |

| Term | Explanation |
|---|---|
| Short run marginal cost (SRMC) | The additional cost of producing one more unit of output from existing 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 dollars per megawatt hour ($/MWh). |
| Short run (average) cost | The cost of starting a generating unit, running it to produce electricity for a short period of time (usually less than 12 hours) and then shutting it down divided by the amount of electricity produced during that period of operation. This is measured in $/MWh. |
| Short Term Energy Market (STEM) | A day ahead contract market that is operated by the IMO, to allow buyers and sellers of electricity to adjust their contract positions on a day to day basis to allow for variations in demand and plant performance and to reduce exposure to the Balancing Market arising from mismatch between supply (for generators) or demand (for retailers) and their contract position. |
| SKM | Sinclair Knight Merz |
| SKM MMA | The former McLennan Magasanik Associates (MMA) team incorporated as part of the Strategic Consulting services of SKM. |
| Synchronisation | Refers to the point in time when a generating unit is connected to the electricity network so that it can be subsequently loaded up to supply power to the electricity system. |
| Type A gas turbine maintenance | Frequent annual preventative maintenance which may only take a few days and does not require major part replacement. Such maintenance is typically undertaken after 12,000 hours or some 600 unit starts. |
| Type B gas turbine maintenance | Hot section refurbishment / intermediate overhaul – typically carried out at around 24,000 running hours or 1200 starts. Major thermally stressed operating parts are often replaced. |
| Type C gas turbine maintenance | Major overhaul of thermally stressed and rotating parts of the gas turbine. Typically undertaken after 48,000 fired hours or 2400 unit starts. |
| WEM | Wholesale Electricity Market as operated by the IMO. |

# 1. INTRODUCTION

## 1.1. Review of Maximum Prices

As part of the market power mitigation strategy for the WEM, there are price caps which limit the prices that may be paid in the STEM and for balancing. The maximum price depends on whether gas or liquid fuelled generation is required to meet the electricity demand when the maximum price applies. The Alternative Maximum STEM Price is applied when gas fired generation is fully committed and liquid fuelled generation is required.

The prices that currently apply are shown below in Table 1-1. Further details are also available on the IMO website: http://www.imowa.com.au/market-data-pricelimits.

- **Table 1-1 Maximum Prices in the WEM**

| Variable | Value | From | To |
|---|---|---|---|
| Maximum STEM price | $323.00 / MWh | 1 July 2012 | 1 July 2013 |
| Alternative Maximum STEM Price | $523.00 / MWh | 1 May 2013 | 1 June 2013 |

Note that the Alternative Maximum STEM Price is adjusted monthly according to changes in the three monthly average price of 0.5% sulphur Gas Oil as quoted in Singapore.

## 1.2. Engagement of SKM MMA

Sinclair Knight Merz (SKM MMA) was engaged by the IMO to assist it in conducting an assessment of the required procedures under the Market Rules to:

- revise the price caps;
- conduct an analysis of costs; and
- prepare a draft and final report.

The Final 2013 Report derived from this Draft 2013 Report will be submitted by the IMO to the Economic Regulation Authority (ERA) for approval under clause 2.26 of the Market Rules.

## 1.3. Basis for Review

The basis for the review of Maximum STEM prices is set out in the Market Rules as shown in Appendix A. The key elements of the process are to:

- review the cost basis for the Maximum STEM Price and the Alternative Maximum STEM Price which applies when liquid fuelled generation is required;
- prepare a draft report for public consultation; and
- finalise the report based upon the public consultation.

The Market Rules specify a methodology in clause 6.20.7(b) related to the costs of a 40 MW gas turbine generator without specifying the type of gas turbine technology – for example aero derivative or industrial gas turbine. The key factor is that the costs should represent the "highest cost generating works in the SWIS". The aero derivative turbines are more flexible in operation, have lower starting costs and generally have higher thermal efficiency. The aero derivative turbines better serve a load following regime and very short peaking duty. The industrial gas turbines are not as well suited to extreme peaking operation and therefore would be expected to be the last units loaded for this purpose, if they were not already running for higher load duty.

The analysis in this report calculates the Energy Price Limits for selected actual industrial gas turbines and aero derivative turbines and selects the highest cost unit as the reference unit.

The formula for calculating the Energy Price Limits is stated as:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance costs for a 40 MW open cycle gas turbine generating station expressed in $/MWh; and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where the IMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

### 1.3.1. Analysis in this Report

The methodology outlined in clause 6.20.7(b) makes explicit allowance for the fact that the applicable costs that make up the estimated SRMC of the highest cost generating works are inherently uncertain. As such there is no single value for all operating conditions. The Maximum STEM Price, being fixed, must be set so that it provides sufficient incentive for peaking plants to provide energy to the STEM and the new Balancing Market in the presence of market uncertainty.

In the equation in clause 6.20.7(b) Variable O&M, Heat Rate, Fuel Cost and Loss Factor are all deterministic values for which an average value can be provided; the uncertainty in the calculation of an appropriate Maximum STEM Price or Alternative Maximum STEM Price is intended to be dealt with through the concept of the Risk Margin.

The analysis in this report seeks to apply industry best practice to establish an appropriate Risk Margin.

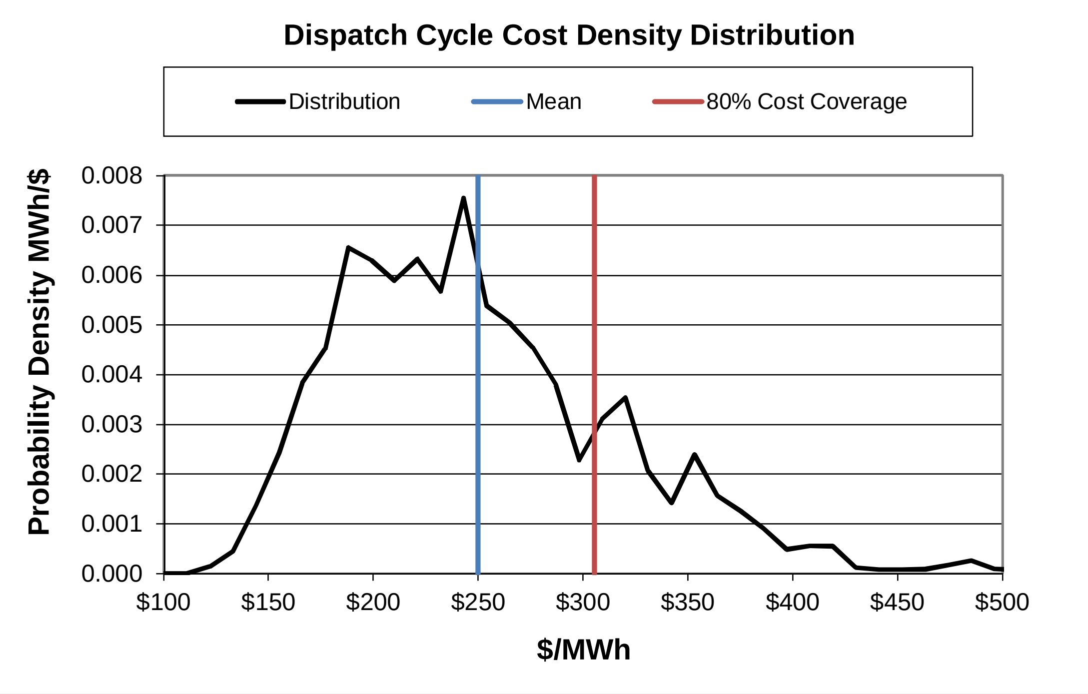
The approach taken to calculate the Risk Margin in this report (as with previous years) is to identify the likely variability in key inputs to the calculation of Energy Price Limits and model the impact that the variability in the key inputs would have on the dispatch cycle cost. This method results in a probability distribution of possible costs from which the recommended price limit is selected to cover 80% of the possible outcomes (representing a 20% probability that the price may be exceeded). The Risk Margin is then the percentage difference between the cost outcome that covers 80% of possible outcomes and the cost derived from the mean inputs according to the formula in clause 6.20.7(b).

This is provided diagrammatically in Figure 1-1 for the operating cost of the Pinjar gas turbines under these cost assumptions and based on the historical dispatch pattern of Pinjar since January 2009. The chart shows the density distribution as a black line, the product of the mean of the formulae inputs as the blue vertical line, and the value exceeded 20% of the time as the red line, which is the proposed Maximum STEM Price in this instance.

SKM MMA notes the probability curve used to calculate the Risk Margin is a subset of all of the possible dispatch cycle cost outcomes. That is, the Risk Margin is based on the 80 percentile outcome for the generation described by clause 6.20.7(b) and does not represent all of the generation that participates in the STEM. It only considers dispatch cycles of between 0.5 and 6 hours duration.

SKM MMA believes this approach most appropriately reflects the intent of setting Energy Price Limits for extreme peaking operation and the concept of the Risk Margin as detailed in clause 6.20.7(b).

- **Figure 1-1 Probability density for price cap calculation for highest cost generator**




Further, SKM MMA also notes that in using this methodology to calculate the Risk Margin, the relevant Energy Price Limits are calculated before the Risk Margin. This makes the concept of the Risk Margin an output of the calculation methodology rather than an input determining the Energy Price Limits.

## 1.4. Issues considered in the Review

In the course of this price cap review, the following issues concerning the methodology have been identified. Issues identified and addressed in previous years' reports have not been detailed in this report.

### 1.4.1. Trend in dispatch of gas turbines

An analysis of Pinjar dispatch showed that the frequency of unit starts has decreased by a factor of two since the new high efficiency gas turbines at Kwinana commenced operation in September 2012. The amount of energy dispatched per cycle has not changed materially. The change in start frequency has been reflected in the representation of Pinjar operation for the 2013/14 financial year, as detailed in section 3.3.1.

### 1.4.2. Start-up fuel consumption for liquid firing

In reviewing the previous cost models, it was noted that the start-up fuel consumption for liquid fuel was increased by 5% on a Higher Heating Value basis. It was realised that this increase should be on a Lower Heating Value basis which equates to a 0.27% increase on a

Higher Heating Value basis. This is consistent with that used for the average heat rates at maximum and minimum capacity. The amendment has no impact on the assessed Energy Price Limits.

### 1.4.3. Carbon emission on distillate transport

In the previous review an allowance was made of 5.3 kg/GJ for the carbon emisisons associated with the transport of distillate, on the assumption that this emission would either be priced in the carbon emissions for power generation or applied to the transport itself and therefore be passed on to the generator. Since carbon pricing has not yet been applied to heavy vehicle transport above 4.5 tonnes weight, this component has been removed from the emission cost associated with the combustion of distillate.

# 2. METHODOLOGY

## 2.1. Overview

This chapter discusses the price cap methodology as it was applied in this review. Previous IMO reports on the Energy Price Limits, particularly the 2009 review, have thoroughly discussed the evolution of these methods.

## 2.2. Concepts for Maximum STEM Prices

### 2.2.1. Basis for magnitude of price

The estimation of the Maximum STEM Price depends on the consideration of a number of factors. Since the purpose of the Maximum STEM Price is primarily to mitigate market power, there are conflicting objectives in setting the Maximum STEM Price, which should be:

- low enough to mitigate market power;
- high enough so as to ensure that new entrants are not discouraged in the peaking end of the market; and
- high enough that generators with duel fuel capability (gas and liquid) do not regularly switch to liquid fuel as a result of short term gas market prices exceeding the basis of the Maximum STEM price.

However, the IMO cannot predict the particular circumstances that would define the highest cost peak loading conditions in any particular period of time. Therefore the value that would be high enough to allow the market to operate cannot be accurately determined by the IMO. A number of factors influence this calculation including plant cost and market factors. The following section discusses how this uncertainty is managed in setting the price caps.

### 2.2.2. Managing Uncertainty

From the viewpoint of the IMO, it does not have perfect knowledge of all the possible conditions that determine the cost of generation at any particular time. Therefore some margin for uncertainty is needed when applying the expected costs to set a price limit.

The Market Rules allow for the uncertainty to the IMO of the short run average cost of peaking power to be assessed and a value to be determined that results in a price cap that exceeds the majority of potential circumstances with an acceptable probability, say 80% to 90%. This range is typical of risk margins observed in electricity markets where traders cannot accurately predict future market conditions and yet must strike a fixed price for trading purposes to manage uncertainty. The margin is applied to the expected cost to ensure that the imposition of a capped price does not impede participation of high cost generators in the market under high demand or low reserve supply conditions.

In the event that future market conditions prove that the Maximum STEM Price is constraining economic operation of peaking plant, the IMO is able to review the price settings to reflect prevailing market conditions and recommend an adjustment to the probabilities. Thus the risk that generators would be financially disadvantaged by the price cap is very low.

## 2.3. Selection of the Candidate OCGT for analysis

The previous analysis of Energy Price Limits has shown that the Pinjar 40 MW gas turbines have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines are the next most costly to run for peaking purposes. This has consistently applied since the Energy Price Limits were first determined. In the 2011 Review, the Kwinana twin sets were included in the analysis and it was shown that they are very unlikely to have higher dispatch costs than the Pinjar gas turbines, and that they do not need to be considered further. There is no reason to suggest that this would change in the foreseeable future. For these reasons the Pinjar 40 MW machines and Parkeston aero-derivative gas turbines are the two candidate machines selected for analysis in this report. The determination of the highest cost machine is discussed further in section 2.5.

## 2.4. Determining the Risk Margin

The methodology in this report seeks to model the uncertainty inherent in the calculation of the Risk Margin in a manner that appropriately covers variability in the key inputs detailed in clause 6.20.7(b) of the Market Rules. These inputs are

- Variable O&M
- Heat Rate
- Fuel Cost
- Loss Factor

The following details the methodology by which the variability in each of these inputs is determined and the process by which these parameters are combined to determine the Energy Price Limit.

Throughout this section the text in square brackets is provided to link the methodology discussion to the variables of the operational formulae in Appendix B.

### 2.4.1. Variable O&M

The determination of Variable O&M costs for the candidate machines is based on engineering data available to SKM MMA and the values used in 2011 have been updated to 2013 cost levels. We were not able to obtain any new data on these costs through recent enquiries.

These O&M costs are incurred in the following manner:

Type 1: Annually whether the unit is operated or not.

Type 2: On a per start basis independent of the time the unit operates for, or loading level. [SUC]

Type 3: On a per hour of operation independent of machine loading. [VHC]

Type 4: On a per MWh basis (variable basis).

Type 1 costs above are not included in the Energy Price Limit determination as they are not considered short run costs. It is expected that such costs would be captured in the Capacity Credit payment mechanism within the market for fixed operating costs.

Types 2 through 4 above must be stated on a per MWh basis to meet the requirements of clause 6.20.7(b) of the Market Rules. As a result Types 2 and 3 require conversion to a per MWh basis. This conversion is achieved by estimating how much generation is associated with each start (Type 2) or hour of operation (Type 3) as applicable. These items are dependent on the duration for which the machine is operational and how heavily loaded the machine is while it is being dispatched. These components change dramatically from machine to machine and are a key source of uncertainty in the development of the Variable O&M. To determine these items SKM MMA uses the concept of the dispatch cycle.

As in previous years, the characteristics of dispatch cycles experienced by the Pinjar and Parkeston machines were determined through the analysis of historic dispatch data obtained from the IMO. This sampled dispatch data is expressed through the following variables:

- The sampled number of starts per year. [SPY]
- The sampled run-time between 0.5 and 6 hours. [RH]
- The sampled dispatch cycle capacity factor as a function of run-time. [CF]
- The sampled maximum capacity. [CAP]

The latter three variables are multiplied to determine the MWh delivered per start [MPR] which divides the start-up operating cost to give the variable O&M. This is shown in detail in Appendix B.

The number of starts per year for Pinjar in the historical period between 1 January 2009 and 31 August 2012 was divided by 2.0 with reference to the reduced start frequency of Pinjar since September 2012 when the high efficiency gas turbines commenced operation at Kwinana. The analysis of these changes is summarised in section 3.3.1.

### 2.4.2. Heat Rate

The heat rate of the reference machines is based on data provided by the manufacturer as available in heat rate modelling software GT Pro. The heat rate characteristics for run-up and for continuous operation were reviewed and refined in the 2012 review. It is not considered necessary to review these data. The manufacturer data reflects that the actual heat rate of the machine varies with the following:

- Machine Load
- Temperature
- Humidity
- Atmospheric Pressure.

For the purpose of this report, heat rates are considered with atmospheric pressure defined at 15 m above sea level and over the range between two conditions:

- temperature of 41°C, humidity 30%
- temperature of 15°C, humidity 60%

The peaking dispatch of the reference machines occurs throughout the year, and therefore the variation of heat rates attributable to temperature variation has been added to the underlying uncertainty. This underlying uncertainty is modelled as having a deviation of 3%[7]. The mean heat rates were interpolated between the above reference temperature values for 25°C corresponding to the mean daily maximum temperature in Perth. Previously the heat rates had been estimated only for 41°C but this is considered a little too pessimistic.

The Market Rules state that the Heat Rate should be determined at "minimum capacity". The concept of minimum capacity itself has a range of associated uncertainties. From an engineering perspective a machine can for short periods be run to almost zero load. However, the associated heat rate and increased maintenance burden make this unsustainable over extended durations. Thus, to identify the appropriate minimum capacity reference SKM MMA reviewed historic machine operation to determine an appropriate minimum load for the reference machines. A heat rate was then extracted from the manufacturer's data for that loading level, as well as the sensitivity of the average heat rate to the variation in output, for modelling the uncertainty in the minimum capacity level. [AHRN]

In addition to the above, the Pinjar machine uses material quantities of fuel during the start-up process that must be considered in the analysis. The start-up fuel and its emission cost is added to the total cost and included as part of the Fuel Cost term. Through this process

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[7] 3% of the heat rate at 25°C obtained by interpolating with the values at 41°C and 15°C

the start-up fuel cost is converted from a fixed fuel consumption to a per MWh consumption using the dispatch cycle concept discussed in section 2.4.1 above. [SUFC]

The “heat rate at minimum capacity approach” is cross checked against a second methodology that establishes the heat rate of the Pinjar machine across the dispatch cycle of the machine and then calculates the aggregate fuel consumption to determine an average heat rate. This approach includes the fuel consumed in start-up and the modelled heat rate for the various load levels as the machine moves through the dispatch cycle, from start-up to shut down. This approach is undertaken with reference to the dispatch cycle method discussed further in section 5.5.1 of this report. This method is not used to determine the recommended Energy Price Limits. Rather, it is used to confirm that the Market Rules can provide Energy Price Limits that reflect the observed pattern of dispatch, and consequently the appropriate heat rate levels.

### 2.4.3. Fuel Cost

This report considers a modelled distribution of likely gas prices to determine the Maximum STEM Price. In addition, SKM MMA has chosen to model the carbon emission cost within the Fuel Cost component of the equation. It is recognised, of the options provided in equation 6.20.7(b) of the Market Rules, that the carbon emission cost could be characterised as an O&M cost component. However, as the quantity of carbon emitted is dependent on the heat rate of the machine and is determined by the quantity of fuel consumed, it has been included in the Fuel Cost component of the analysis for simplicity.

**Gas Cost**

The modelling of gas cost is based on the recommendations with the 2013 ACIL Tasman Final Report[8]. ACIL Tasman used a lognormal approximation to represent the composite gas price distribution. However, SKM MMA has selected a tri-lognormal distribution of gas prices over a predefined range as a slightly better fit to the composite distribution. Of critical importance to the setting of the Maximum STEM Price is the definition of the upper bounds of this distribution. In this report the upper bound of this distribution is defined by the gas cost that would give the same dispatch cycle cost as if distillate were used. This is because it is considered unlikely that the spot gas price would exceed the value of gas in displacing distillate usage in open cycle gas turbines. This situation reflects the significant capacity for dual fuelled gas turbines in the SWIS, including Pinjar. In defining this upper bound, a position must be taken on the delivered price of distillate and the quantity of distillate required to deliver the same energy as a unit of gas. The latter item is dependent on the generation technology adopted (industrial machines versus aero derivatives) when comparing the results to determine the highest cost OCGT. [VFC] and [FSR]

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[8] Gas Prices in Western Australia, 2013/14 Review of inputs to the Wholesale Electricity Market, Final Report prepared for the Independent Market Operator by ACIL Tasman, February 2013

**Transport Cost**

The gas transport costs are also based on the recommendations in the 2013 ACIL Tasman report. These costs have been generally modelled as variable costs [VFTC]. However, for the Parkeston machines, parts of the costs recommended by ACIL Tasman have been treated as fixed costs [FT].

**Daily Load Factor**

The impact of variation in daily forecast volume error is modelled through the inclusion of a daily gas load factor [VFTCF]. This daily gas load factor is applied to the fixed transport cost [FT] and the gas cost [VFC].

**Carbon Cost**

The methodology for modelling the carbon cost is to convert this to an equivalent fuel cost based on the specification of the carbon intensity of the WA gas supply using the National Greenhouse Gas Account Factors for gas and distillate as discussed in section 3.5. No variability is modelled in the cost of carbon in this year's report [FER] and [CP].

### 2.4.4. Loss Factor

The loss factor is extracted from the published loss factors for the candidate OCGTs. As this is a published figure no variability is modelled for this input; that is a single data point is used. [LF]

### 2.4.5. Determining the Impact of Input Cost Variability on the Energy Price Limit

For each candidate machine and for each of the variables detailed above a range and a distribution are applied from one of the following options:

- Assume the variable is normally distributed and assign a standard deviation with the base value representing the mean, and then apply maximum and minimum limits if appropriate.
- When specific information is available from the WEM or other sources, SKM MMA has analysed the information and derived a suitable probability distribution to represent the uncertainty. This method has been used to analyse run times, generation available capacity and generation capacity factors related to the dispatch cycle.

For each candidate machine, these distributions are used to develop a set of 1000 input combinations to the equation detailed in Appendix B. Based on the distribution of the inputs, this equation is processed for each of this set of inputs to provide a profile of possible costs determining the Energy Price Limits. From this profile a potential Energy Price Limit is selected that covers 80% of the outcomes for that generator.

### 2.4.6. Determining the Risk Margin

To determine the Risk Margin associated with the Energy Price Limit determined through the process described in section 2.4.5 above the following process is adopted. The mean values of the relevant probability distributions described above are used to calculate the term

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

in clause 6.20.7(b) from which the Risk Margin is determined to match the Energy Price Limit. Hence the Risk Margin is calculated as:

$$\text{Risk Margin} = \frac{\text{Energy Price Limit as determined in section 2.4.5}}{(\text{Variable O\&M} + (\text{Heat Rate} \times \text{Fuel Cost}))/\text{Loss Factor}} - 1.0$$

This method respects the construction of the Energy Price Limits as currently defined in the Market Rules whilst providing for an objective method for defining the Risk Margin having regard to an analytical construction of the market risk as perceived by the IMO using public data.

SKM MMA notes that the start-up fuel consumption [SUFC] is included in the Heat Rate input. That is the heat rate for the purposes of clause 6.20.7 (b) includes both the steady state heat rate at minimum [AHRN] and a component that covers the start-up fuel consumption [SUFC]. The option of presenting the start-up fuel cost in the Variable O&M input was considered; however SKM MMA felt as this component was part of the fuel consumption of the machine it was best presented in the heat rate.

## 2.5. Determination of the Highest Cost OCGT

Based on the analysis above for Parkeston and Pinjar the unit with the highest Maximum STEM Price is selected. As in previous years the model Pinjar units have been identified as the highest cost machines. To simplify the report the calculations for Pinjar are presented in Chapter 3. The corresponding analysis for Parkeston is provided in Appendix D.

## 2.6. Alternative Maximum STEM Price

Although the Alternative Maximum STEM Prices is calculated consistent with the requirements of clause 6.20.7(b) detailed above it is recalculated monthly based on changes in the monthly Singapore Gas Oil price (0.5% sulphur). This defines the delivery of the Alternative Maximum STEM Price in this report as a function of distillate price in Australian dollars per GJ. It also removes uncertainty in the cost of distillate from consideration in determining the Risk Margin discussed above.

The Lower Heating Value heat rates for industrial gas turbines and aero-derivative machines are increased by 5% for the calculation of the Alternative Maximum STEM Price to represent the operation conditions when fired on distillate. When adjusted for the ratio of lower to Higher Heating Value on the two fuels, the effective increase in Higher Heating Value is 0.27%. This factor was also applied to the start-up fuel consumption.

The Risk Margin for the Alternative Maximum STEM Price is determined by calculating the dispatch cycle cost that is exceeded in 80% of dispatch cycles of less than 6 hours for a fixed distillate price. This enables an equation to be determined with a fuel independent ("non-fuel") component plus a "fuel" cost component that is proportional to the delivered distillate price. This is presented in section 4.1.1.

The method for the selection of the non-fuel and the fuel cost factor in the formula for the Alternative Maximum STEM Price was based upon 1,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $15/GJ and $45/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown with the results in Figure 4-1. This method ensures that the resulting cost is at the 80% probability level over this fuel cost range, given the cost and dispatch related uncertainties.

The non-fuel cost component for the Alternative Maximum STEM Price includes the emission cost as this cost is not dependent on the fuel cost. The elements which make up these cost components are shown in Appendix B.

# 3. DETERMINATION OF KEY PARAMETERS

This chapter discusses the analysis of the various cost elements and how they are proposed to be used to set the Energy Price Limits using their probability distributions and mean values. This section is structured to follow the cost elements as defined in clause 6.20.7(b) of the Market Rules. A summary of the operational distributions of the input variables is provided in Appendix B. More detailed information on gas prices is provided in Appendix C. Other probability distributions are described in a confidential Appendix provided to the IMO and ERA. The calculations for the aero-derivatives are presented in summary form in Appendix D.

## 3.1. Fuel Prices

### 3.1.1. Gas Prices

The analysis of gas prices has been based on the aforementioned ACIL Tasman Final Report. The recommended approach was to base gas price and transport cost on spot gas trading as in the year from 1 July 2013. The value of gas will be based on the opportunities in the spot gas market for gas that would be used by a 40 MW peaking plant at Pinjar.

### 3.1.2. Price of gas

The price of gas delivered to a 40 MW power station has two components, 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. In this study the gas price has been estimated on the basis that the gas is sourced from the Carnarvon Basin and transported to generators in the South West via the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

The spot market gas price, which excludes the transport component, has been based upon alternative uses, either in:

- displacing contracted gas which is not subject to take-or-pay inflexibility
- changes in industrial processes, or
- displacing liquid fuel in power generation or mineral processing.

These alternative uses have a wide range of values and ACIL Tasman has assessed a range from $5.02/GJ to $11.56/GJ as representing 80% of the range of uncertainty[9]. ACIL Tasman suggested that a spot gas price could range from around $4.20/GJ to $4.40/GJ (while reporting some small sales as low as $1.97/GJ) up to 90% of the distillate equivalent

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[9] SKM MMA refined the composite distribution modelling using three lognormal distributions and obtained an 80% confidence range from $4.98/GJ to $11.54/GJ which is very similar to the single lognormal equivalent.

price of $22.68/GJ. ACIL Tasman said this was to "to retain some advantage for the generator to use gas rather than distillate".

As described in section 2.4.3 above, a gas price range up to $24/GJ has been modelled with the gas price capped by the comparative value relative to the distillate price[10]. SKM MMA has calculated a breakeven gas price for each of the 1000 simulated dispatch cycles given its particular characteristics, including a cost penalty for liquid firing where applicable for industrial gas turbines[11]. The breakeven price was estimated to equalise the dispatch cycle average energy cost. This is preferable to capping the gas price distribution at a single level when estimating the Energy Price Limits.

SKM MMA has chosen to represent the gas price as continuously distributed between $2/GJ and $24/GJ using three lognormal distributions to represent the composite distribution developed by ACIL Tasman, as shown in Figure C- 1 in Appendix C. This range represents 99.995% of the underlying continuous distribution. The mode of the continuous section is at $6.604/GJ as recommended by ACIL Tasman[12]. The resulting gas price distribution as sampled was as shown in Figure 3-1. The smooth black line represents the density function for the gas price from which 1000 samples were drawn. The blue line shows that the gas price distribution was slightly truncated at the high price end.

It may be noted that the sampled gas price did not exceed $18.88/GJ for the industrial gas turbine. Thus modelling the gas price to $24/GJ was sufficient. The maximum delivered gas price was $21.78/GJ to the industrial gas turbines.

### 3.1.3. Daily load factor

ACIL Tasman has stated that when applied to spot trading on a daily basis, the daily gas load factor is only important to the extent that it represents daily forecast volume error. For that purpose, it is modelled as having an 80% confidence range between 80% and 98% with a 95% most likely value (the mode). The continuous distribution had a mean of 97.0%, but when the maximum value of 1.0 was used to truncate the distribution, the mean value was 89.91%. SKM MMA developed the lognormal distribution of Spot Gas Daily Load Factor shown in Figure C- 3. The distribution was truncated and redistributed so that there was no discrete probability of a value of 100%. This was in accordance with the spreadsheet model provided by ACIL Tasman. There is a 0.005% probability of a value at the minimum value 60%.

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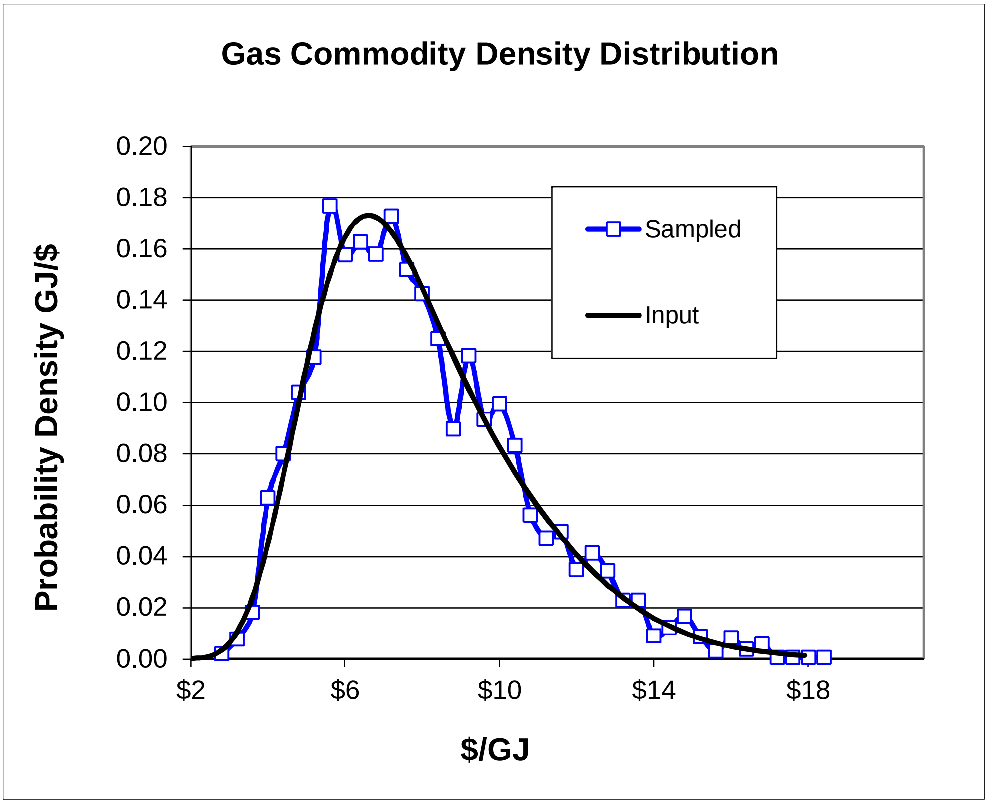
[10] The distillate price cap is discussed further in section 3.1.6 of this report.
[11] No liquid firing operating cost penalty was applicable to aero-derivative gas turbines which are designed to use liquid fuel.
[12] The mode of the distribution as fitted by ACIL Tasman was stated to be $6.80/GJ, although the sampled composite distribution had its highest sampled value at $6.40/GJ in $0.1/GJ steps. SKM MMA's distribution has a closer fit to the composite distribution at $6.60/GJ.

▪ **Figure 3-1 Gas Price distribution as modelled with upper price limited to the distillate equivalent**




Note: Gas price excludes the carbon emission cost

The effective spot price was calculated by dividing the spot price sampled from the capped distribution in Figure C- 1 by the daily load factor sampled from the capped distribution in Figure C- 3.

### 3.1.4. Transmission charges

ACIL Tasman has recommended basing the gas transport cost on spot market conditions. For the transport to Perth, a lognormal distribution is recommended with the 80% confidence range being between $1.46/GJ and $2.15/GJ with a most likely value (mode) of $1.735/GJ[13]. The mean value of the transmission charge is $1.795/GJ. SKM MMA developed the distribution shown in Figure C- 4 in Appendix C to represent this uncertainty

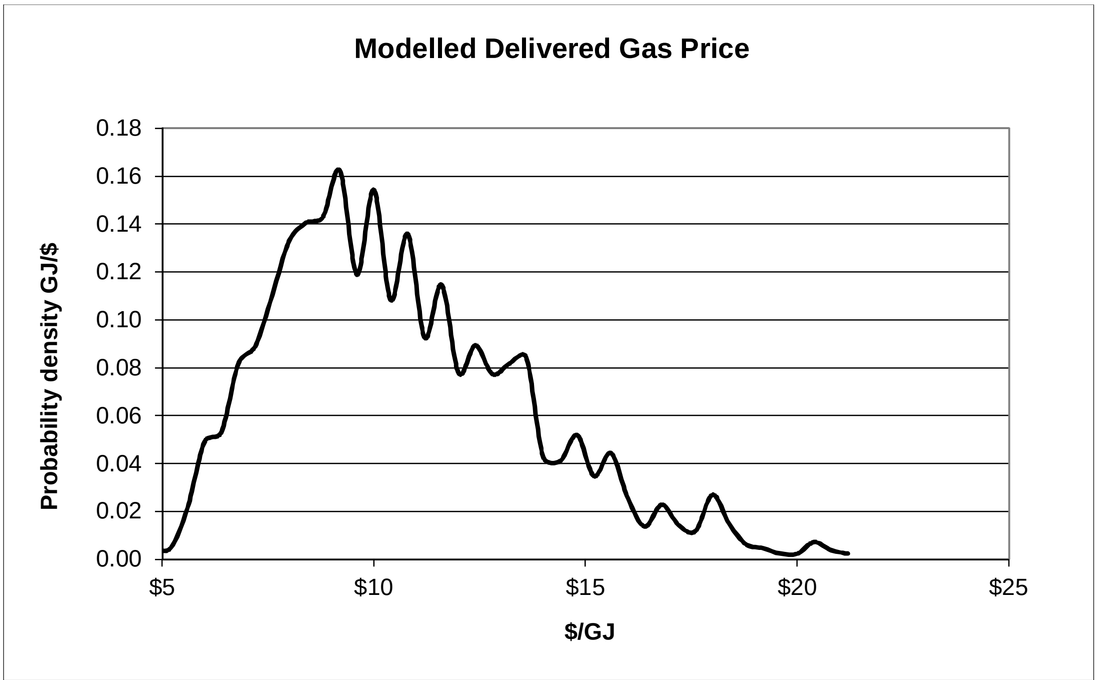
[13] ACIL Tasman's distribution model was defined by means of a histogram at a precision of $0.01/GJ and the mode was assessed as $1.74/GJ at this precision. The parameters fitted by SKM MMA showed a mode of $1.735/GJ based on analysis using the distribution parameters.

in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with the spreadsheet provided by ACIL Tasman for the 2013 review.

### 3.1.5. Distribution of Delivered Gas Price

The composite of the variation in the gas supply price, the gas transport price and the daily load factor applied to the gas commodity price results in the probability density for delivered gas price shown in Figure 3-2. The effect of the two skewed distributions is to spread the effect of the capped prices and to result in a range of sampled prices as shown in Table 3-1.

- **Figure 3-2 Sampled probability density of delivered gas price to Pinjar for peaking purposes**




The modelled delivered gas price for the Perth region had an 80% confidence range of $7.14/GJ to $14.94/GJ with a mode of $9.20/GJ and a mean of $10.68/GJ. These values exclude pass on of carbon costs in gas price for supply and transport.

### 3.1.6. Distillate Prices

The Market Rules provide for a monthly re-calculation of the Alternative Maximum STEM Price based on assessment of changes in the Singapore Gas Oil price (0.5% sulphur). Therefore in this analysis a reference distillate 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 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

**Table 3-1 Modelled delivered gas price distribution to Pinjar**

| Delivered Gas Prices as Modelled | |
|---|---|
| | **Pinjar** |
| Min | $4.34 |
| 5% | $6.50 |
| 10% | $7.14 |
| 50% | $10.15 |
| Mean | $10.68 |
| Mode | $9.20 |
| 80% | $13.19 |
| 90% | $14.94 |
| 95% | $16.45 |
| Max | $21.78 |

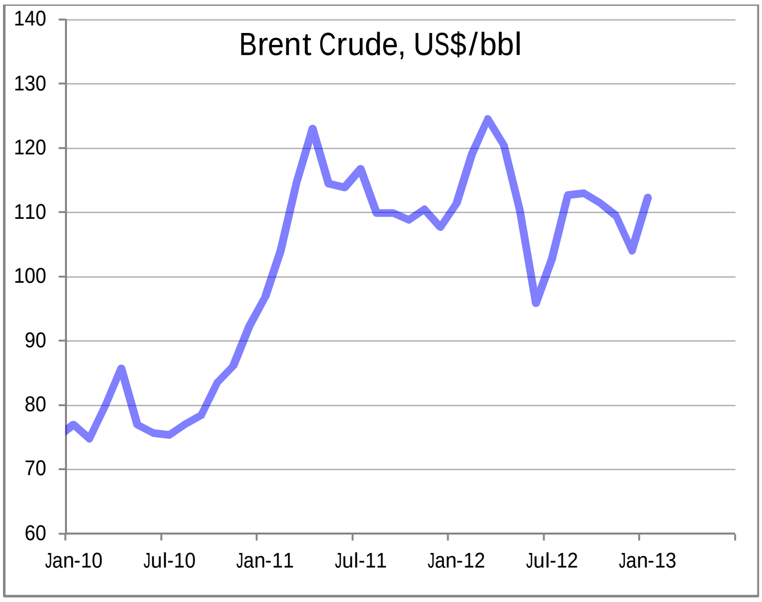
cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location, Pinjar in this case. The following discussion describes the expected level and uncertainty in distillate price for capping the gas price.

Globally, crude prices remained at elevated levels averaging US$111.7/barrel during 2012, just eclipsing the previous all time high in 2011 by a mere US$0.80/bbl. Brent crude continued to cement its position as the global crude marker, with futures trading volumes surpassing those of WTI during 2012. Following a relatively stable period of crude prices in the second half of 2011, Brent crude price increased from US$111/barrel at the beginning of 2012 to US$125/bbl in March before dropping back to US$96 and finishing back virtually where it started at US$109/bbl (refer Figure 3-3). The crude price band in 2012 was US$29/bbl while the standard deviation was US$7.60/bbl, (cf 2011 US$26 and US$6.60 respectively).

The volatility of crude prices increased slightly in 2012. This was caused by the continuation of a series of geopolitical events, particularly the tensions between Israel and Iran in the Middle East, between China and Japan in East Asia and the general sabre rattling by North Korea. The debt crisis in Europe continued to feed uncertainty into the market as did the US management of its national debt. The full effect of the emergence of shale oil reserves

SINCLAIR KNIGHT MERZ SKM MMA

- **Figure 3-3 Brent Crude price 2010 to 2013**




around the globe has yet to be seen in crude prices, although it could be argued that prices would have been much higher had these reserves not materialised.

The latest estimate of crude prices from the US Energy Information Agency, EIA, (December 2012)[14] which for the first time used Brent crude as the reference crude price, has Brent prices averaging between US$95 and US$100 from 2013 to 2015. In the more recently published short term energy outlook (12 February 2013), the EIA forecast prices averaged US$109/barrel in 2013 and US$101/bbl in 2014, reflecting increased supplies of crude from non-OPEC members. These numbers imply a price of US$105/bbl for Brent in the 2013/14period. However, escalation of any of the geopolitical issues currently bubbling away in the background will quickly move prices up by US$10-20/bbl.

On the assumption that there is no escalation of any current or new geopolitical issue, the Brent price expectations during the subject period are estimated at approximately US$108/barrel.

Regionally, the monthly average spot price for Singapore Diesel, (Australian 10 ppm sulphur grade) was slightly less volatile than the crude prices, moving from US$130/barrel early in 2011 to a high of US$139/barrel in March, a low of US$113 in June and finishing around US$127/bbl. As anticipated, the gasoil to crude spread was stronger in 2012 averaging US$18/bbl, supported primarily by the continuing strength in the China economy. There are widely divergent views on the underlying strength in the Chinese and surrounding Asian economy and analysts are generally less optimistic in their outlooks. Whilst to date there is

[14] EIA Annual Energy Outlook 2013 Early Release

no evidence of significantly negative signals being reflected in refinery operations in Singapore and bearing in mind the latest EIA forecast, Diesel prices in Singapore for the subject time period are expected to average US$125/barrel. This forecast assumes that there are no new significant geopolitical events during this period.

It should be noted that as of 2 January 2013, the Platts product assessments ceased to include the standard 0.5% gasoil. The standard gasoil assessment in Singapore is now the 0.05% gasoil. This change should have no material effect on the assessments of the 10 ppm gasoil used to price diesel in Australia.

The above forecast for the Singapore 10 ppm diesel price of US$125/bbl translates to a wholesale price, (Terminal Gate Price), in Perth, Western Australia of 132.8 Ac/litre, (Acpl). For comparison, this is based on an AUD/USD exchange rate of 1.03. This price results in a Free into Store (FIS) price of 133.887 Acpl for Pinjar and 138.016 Acpl for the Parkeston power stations. after applying a road freight cost of 1.087 Acpl in the Perth region and 5.216 cpl for the Goldfields. This equates to a diesel price of $1.217/litre ex GST for Pinjar and $1.255/litre for Parkeston. This is equivalent to $21.65/GJ and $22.62/GJ for the two power stations respectively after deducting 38.143 cents excise and GST and applying a heat value of 38.6 MJ/litre. It is assumed that Verve Energy will pay the carbon price assessed in section 3.5 rather than accept the standard excise discount for the carbon price of 6.521cpl which applies to distillate for power generation. Both methods yield the same Energy Price Limits.

Over the period relevant to the Maximum STEM Price the price of distillate will vary due to fluctuations in world oil prices and refining margins. Based on the recent volatility in crude prices, the distillate price is assumed to have a standard deviation of about 6%, represented as 7.5cpl. This translates to $1.94/GJ. This standard deviation is greater than was applied in the 2012 Review ($1.30/GJ).

For this review, in capping the gas price the distillate price has been modelled as a normal distribution with a standard deviation of $1.94/GJ. A mean price of $21.65/GJ has been applied in the Perth region for Pinjar.

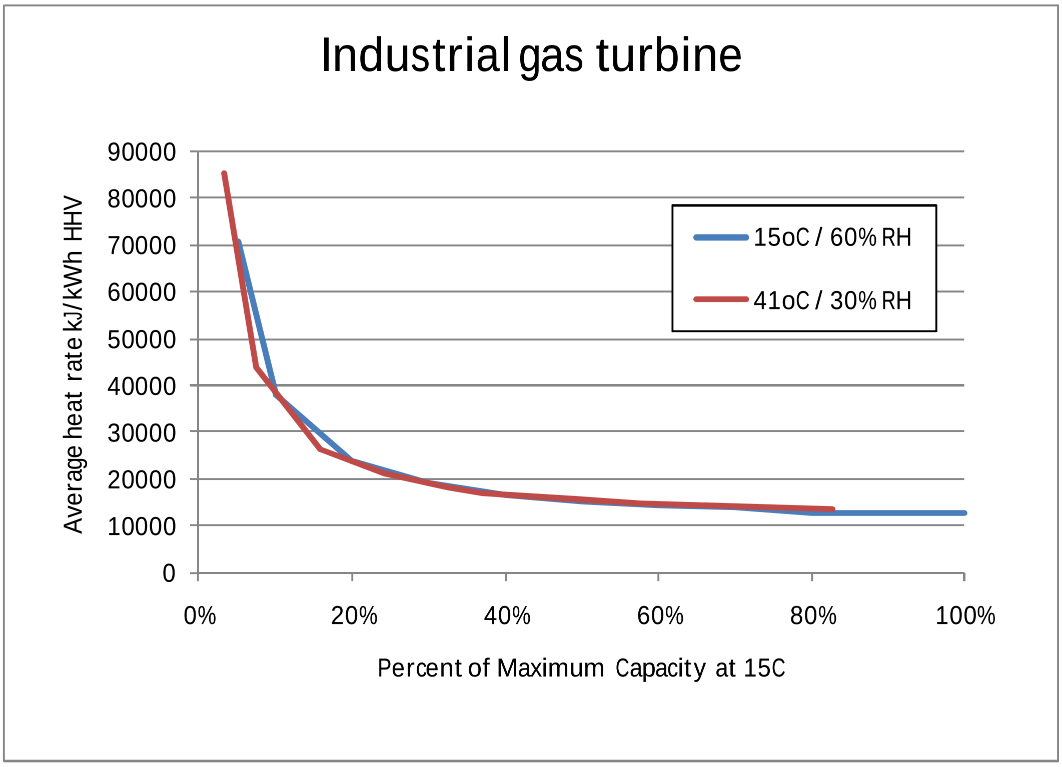
## 3.2. Heat Rate

### 3.2.1. Start-up

The start-up heat consumption was estimated by SKM MMA as 3.50 GJ for the industrial gas turbine and 3.53 GJ for the aero-derivative gas turbine. An additional 5% of heat energy was allowed for start-up on distillate at Lower Heating Value which equates to 0.27% at Higher Heating Value as discussed above in section 1.4.2. A 10% standard deviation was applied to these values with a normal distribution limited to 3.2 standard deviations.

Figure 3-4 shows the run-up heat rate curve applied for the industrial gas turbine to calculate the energy used to start the machine.

- **Figure 3-4 Run-up Heat rate curve for industrial gas turbine (new and clean)**




### 3.2.2. Variable heat rate curve for dispatch

Table 3-2 shows the steady state heat rates that were applied for the industrial gas turbine. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

- **Table 3-2 Steady state heat rates for new and clean industrial gas turbines (kJ/kWh HHV)**

| | | % site rating | | | |
|---|---|---|---|---|---|
| Temp | Humidity | 100% | 50% | 33% | 25% |
| 15°C | 30% | 12990 | 15843 | 18711 | 21438 |

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table 3-2. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 18.628 GJ/MWh and a standard deviation of 1.589 GJ/ MWh. These values have increased slightly from the 2012 Review due to an increase in the assessed uncertainty of the minimum operating level based on the analysis of actual dispatch for the Pinjar gas turbines. The change in the assessed minimum operating level changes the average heat rate modelled even though the heat rate characteristics have not been changed since the 2012 Review. The average minimum capacity level was not altered in the 2013 Review.

### 3.3. Variable O&M

This section describes the structure of the variable O&M costs for the Pinjar gas turbines. The equivalent data for the less costly aero-derivatives is discussed in Appendix D.

The variable O&M cost for the Pinjar gas turbines in $/MWh is influenced by Type 2 and Type 3 maintenance costs discussed in section 2.4.1 above. SKM MMA has not identified any significant component of operating cost which depends directly on the amount of energy dispatched. Therefore there is no specific $/MWh component other than that derived from the above costs.

#### 3.3.1. Dispatch Cycle Parameters

An analysis of the Pinjar dispatch patterns over the last four years has shown that:

- Pinjar run times since January 2009 have averaged around 16.1 trading intervals per dispatch cycle. This level is unchanged from the 2012 review. The average power generation per dispatch cycle has remained stable over the whole period.
- Overall the incidence of short run times below 6 hours has been reducing slowly in the Pinjar and the Parkeston dispatch since the distributions were first formulated in 2007 and in the updates for the 2009 to 2012 reviews. However within the 6 hour dispatch window used to determine the Energy Price Limits, the relative incidence of cycles more than 1.5 hours has decreased since the 2011 and 2012 reviews

**Number of starts per year**

The Kwinana LMS100 gas turbines commenced operation in September 2012. An examination of the Pinjar dispatch data from September 2012 has shown a halving of the number of starts per month from the average of the last three years from January 2009. This change indicates a change in the role of Pinjar, and that averaging the number of starts over the period from January 2009 is very likely to over-estimate the number of starts per year in the year commencing 2013/14. SKM MMA has therefore recommended that the pattern of starts between January 2009 and the end of August 2012 should be used to assess the frequency of starts and that this value should be halved for the purpose of forecasting Pinjar dispatch patterns from 1 July 2013.

From the operating characteristics of the Pinjar gas turbine machines between January 2009 and August 2012, they have been required to do between 101 and 187 starts per year on an individual basis, 152.7 starts per year on average, with average run times of between 7.2 and 8.8 hours on a unit basis. This means that the number of starts per year is the primary cost driver, rather than the operating hours.

The number of starts for the six units has a standard deviation of 59.2 starts in a period of one year[15]. This has been represented by a normal distribution up to 3.2 standard deviations from the mean with a minimum number of starts of 10.

After applying the halving adjustment for the period from July 2013, the parameters for the modelling of unit start frequency were:

| | |
|---|---|
| Mean value | 76.4 starts/year |
| Standard deviation | 29.6 starts/year |
| Minimum value | 10 starts/year |

**Run-times**

Run times are used to convert start-up costs for maintenance and fuel into an average operating cost per MWh of a dispatch cycle.

The run times of the peaking units have been analysed from the market data from 1 January 2009 to 31 January 2013. A probability density function has been derived which represents the variation in run times. Whilst it would be possible to set a minimum run time of say 1 or 2 trading intervals, this condition occurs very rarely, about 1 in 40 starts for the industrial gas turbine over the last four years [16]. Since other market factors have also been varied, it is preferred to assess the variation of run time as just another uncertain factor rather than treat it as a deterministic variable.

**Maximum capacity**

The maximum capacity of the Pinjar machines varies during the year due to temperature and humidity variation. The maximum capacity was derived from historical dispatch information taking into account the seasonal time of year using a sinusoidal fitting function. In this way, the variation of the maximum output during the year is included in the uncertainty analysis. A sinusoidal curve was used to estimate the maximum dispatch and

[15] The standard deviation of the number of starts per year over the six units is 30.90 from 1 January 2009 to 31 August 2012. This has been multiplied by the square root of 3.67 (years) to estimate the standard deviation within one year (59.17 starts/year)

[16] While the aero derivative gas turbine has higher frequency of shorter runs it should also be pointed out that it has longer average run time per start than the industrial type gas turbine. This probably reflects bilateral energy contract obligations and higher efficiency than for the industrial turbines.

the error around this curve was added back to give an overall distribution of maximum capacity. The applicable distributions are provided in a confidential Appendix to the IMO and the ERA.

**Dispatch cycle capacity factor versus run-time**

The Market Rules specify the use of the average heat rate at minimum capacity. As previously, the available loading data was analysed to assess what actual loading levels have been achieved, especially with shorter run times. A capacity factor for the dispatch cycle was defined from the historical dispatch data by the following equation:

$$\text{Capacity Factor} = \frac{\text{Energy Generated in Dispatch Cycle}}{\text{Maximum Capacity x Run Time}}$$

The capacity factor varied quite markedly even for similar run times. The relationship between these variables was defined as follows. The capacity factor has a mean equal to a linear function of the run time up to a certain threshold and then a different linear relationship above the threshold. The standard deviation of the capacity factor was assessed with one value below the threshold and another value above the threshold. The details were provided in a confidential Appendix to the IMO and the ERA.

The standard deviation of the variation was 9.0% for run times of 1 trading interval or more. These values were used to formulate the capacity factor which was then clipped between the practical maximum and minimum values having regard to ramp rates and minimum stable operating capacity levels.

### 3.3.2. Maintenance costs

SKM MMA has not been able to source any later information than that obtained in 2011 for maintenance costs. The costs are shown in Table 3-3 in December 2013 dollars for General Electric Frame 6 gas turbines with the maintenance stage occurring after the stated number of running hours or the stated number of starts, whichever comes first. In the maintenance cycle there are two Type A overhauls, one of Type B and one Type C at the end. The costs were originally provided in March 2011 $US dollars. They were converted to Australian dollars at the rate ($AUD = $US1.03) and were then escalated to December 2012 Australian dollars based on Australian CPI and then further escalated by 12 months at 2.5% pa escalation to bring them up to estimated December 2013 dollars.

It should be noted that the Type B overhaul is more expensive that the Type C overhaul because spare parts are purchased for the Type B overhaul to replace parts which are then refurbished for the Type C overhaul, which is therefore less expensive because parts have been reused.

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▪ **Table 3-3 Overhaul costs for industrial gas turbines (December 2013 dollars)**[17]

| Overhaul Type | Number of hours trigger point for overhauls | Number of starts trigger point for overhaul | 2013 Cost per Overhaul | Number in each overhaul cycle | Cost |
|---|---|---|---|---|---|
| A | 12000 | 600 | $886,304 | 2 | $1,772,608 |
| B | 24000 | 1200 | $3,743,428 | 1 | $3,743,428 |
| C | 48000 | 2400 | $1,469,642 | 1 | $1,469,642 |
| | | | | | $6,985,679 |

No adjustment is applied for any future changes in foreign exchange rates. Each maintenance cycle of 2400 units starts and ends with a Type C overhaul.

From the IMO's viewpoint, it does not know where each generating unit has progressed in the maintenance cycle. In simple terms:

- the average running hour cost is $6,985,679 / 48,000 = $145.54/hour = $3.82/MWh at full rated output (38.081 MW)[18]
- the average start cost is $6,985,679 / 2400 = $2,911/start
- one start is equivalent to 20 running hours, but (in the G.E. methodology) they are not interchangeable, as an overhaul is indicated either by the starts criterion or the hours-run criterion, rather than a mixture of the two.

However, these costs are spread over several years and it is not appropriate to divide these costs by the number of starts or number of running hours to derive an equivalent cost accrual.

To account for the fact that the maintenance costs in Table 3-3 are distributed over several years and that the IMO does not know when each unit has been maintained and where it is in its long-term maintenance cycle, SKM MMA has assumed an average point in time across the maintenance cycle and that all future maintenance is spread over a remaining 20 year life.

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[17] Values in the Table 3-3 do not add up due to rounding.

[18] Calculation based on rate of output for a new machine at 15ºC, 60% relative humidity. The O&M cost is calculated based on a sampled capacity derived from market dispatch data in the Energy Price Limits cost model.

For each cycle SKM MMA has calculated a discount factor on the future maintenance cost as:

1/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

Where:

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the average number of starts per year at 76.4; and

Log is the natural logarithm.

The formula is derived from the integral of the present value function of the future maintenance costs over the range of time from zero to CL/SPY years.

PV(t)  = X / (1 + DR) ^ t

Where :

X is the maintenance expenditure at future time t with real discount rate DR; and

PV(t) is the present value of the future maintenance expenditure in year (t).

PV(t) is integrated with respect to (t) over the range 0 to CL/SPY and multiplied by SPY/CL to obtain an expected present value given that (t) is unknown and assumed to be uniformly distributed over the maintenance cycle.

Thus the total cost is:

X/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

The scaling factor is a function of the discount rate and the average number of starts per year.  A lower number of starts effectively increase the discounting of future maintenance costs per start because it has the effect of delaying the subsequent scheduled overhauls to later years.

Table 3-4 shows an assessment for industrial gas turbine at 76.4 starts per year.  The table shows the various scheduled maintenance stages, the corresponding cost and discounted cost as well as a 20% allowance for additional unscheduled maintenance that would arise from normal peaking operations.

- **Table 3-4 Assessment at 76.4 starts/year (historical dispatch)[19]**

| Overhaul Type | Number of starts trigger point for overhaul | Cost per Overhaul | Number in an overhaul cycle. | Cost | Average Discounted Cost |
|---|---|---|---|---|---|
| A | 600 | $886,304 | 1 | $886,304 | $305,454 |
| B | 1200 | $3,743,428 | 1 | $3,743,428 | $1,290,128 |
| A | 1800 | $886,304 | 1 | $886,304 | $305,454 |
| C | 2400 | $1,469,642 | 1 | $1,469,642 | $506,495 |
| Discounted Cost per start | | $1,003 | | $6,985,679 | $2,407,532 |
| Total Scheduled Cost | | $1,003 | | | |
| Unscheduled Cost Ratio | | 20% | | | |
| **Total Cost** | | $1,204 | **Based on** | **76.4** | **Starts / year** |

The start-up cost at 76.4 starts per year is now $1,204/start, compared with the value of $1,879/start in 2012. The significant reduction in discounted start cost is due to the reduction on the average number of starts per year from 160.8 in the 2012 Review to 76.4 in this Review.

For the average historical MWh production per start (including dispatch cycles greater than 6 hours) of 120.1 MWh, the equivalent variable (non-fuel) O&M cost derived from the discounted start cost of $1,204 is $10.02/MWh compared to $14.49/MWh in 2012.

In the simulation of variable O&M cost SKM has taken the start-up cost based on the average number of starts per year, that is with 76.4 starts per year with a standard deviation of 39% of that value (29.6 starts/year on an annual basis) based on the observed variability of the number of starts per year on a specific unit basis (30.90 starts/year over the four years before adjustment)[20].

The formulation of the capacity, run-times and capacity factors is shown in Appendix B.

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[19] Values in Table 3-4 do not add due to rounding.

[20] The 39% value is determined from the overall standard deviation of the number of starts per year for the six Pinjar machines (30.90) multiplied by the square root of the analysis period (3.67 years). $51.97 = 30.90*(3.67)^{0.5}$ This value is then halved to reflect the reduced dispatch since September 2012.

### 3.3.3. Resulting Average Variable O&M for less than 6 hour dispatch

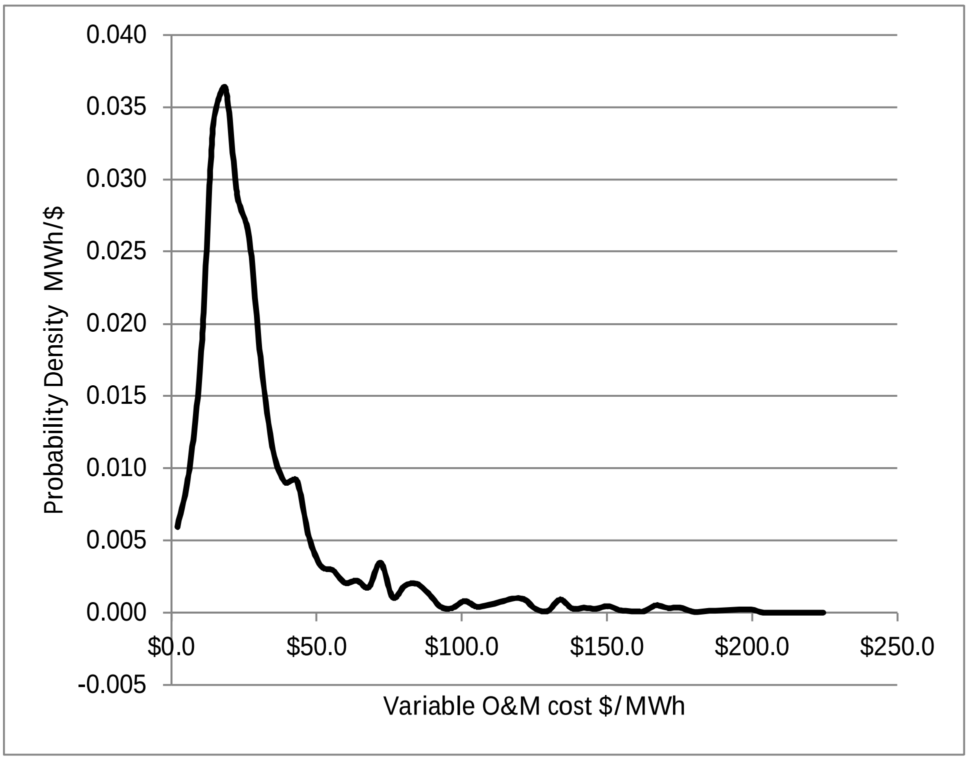
For the sampled generation levels up to 6 hours based on the historical dispatch, the average variable O&M value is $32.04 MWh before the application of the loss factor. The resulting distribution which provides this mean value is shown in Figure 3-5.

Based on the start cost of $1,204, the average variable O&M of $32.04/MWh corresponds to an equivalent generation volume per cycle of 37.58 MWh, equivalent to about one hour running at full load or 3 hours at minimum load. It is these short dispatch cycles which are covered by the resulting Energy Price Limits.

Table 3-5 shows the characteristics of these distributions before loss factor is applied.

The analysis detailed above for the historical dispatch results in an average variable O&M cost of $32.04/MWh with an 80% confidence range as sampled between $10.95/MWh and $64.26/MWh, excluding the impact of loss factors.

- **Figure 3-5 Probability density of variable O&M for industrial gas turbine (excluding impact of loss factor)**



- **Table 3-5 Parameters of variable O&M cost distributions (before loss factor adjustment)**

| Pinjar Var O&M | ($/MWh) |
|---|---|
| 90% POE | $10.95 |
| Mean | $32.04 |
| 10% POE | $64.26 |
| Minimum | $2.01 |
| Median | $22.87 |
| Maximum | $251.88 |
| Standard Deviation | $30.55 |

### 3.4. Transmission Marginal Loss Factors

The transmission loss factors applied were as published for the 2012/13 financial year for sites where aero derivative gas turbines and industrial gas turbines of 40 MW capacity are installed. The loss factor for Pinjar for the 2012/13 financial year is 1.0295.

The loss factors will not be available until near the beginning of the financial year, so it is expected that the IMO will need to make last minute adjustments. The loss factor for Pinjar for 2012/13 has been applied in this analysis. Parameters should be scaled directly for any change in the Pinjar loss factor published for 2013/14[21]. Since a higher loss factor reduces the Energy Price Limits, the relationship is mathematically inverse, that is a 1% increase in the loss factor would reduce the Energy Price Limits by 1-1/(1+1%) = -0.99%.

### 3.5. Carbon price

From 1 July 2013, the carbon price is legislated to increase from $23.00/tCO$_2$e to $24.15/tCO$_2$e. The pricing of carbon emissions adds to the effective dispatch cost of peaking generation through the emissions associated with the consumption of fuel for start-up and operation. In terms of clause 6.20.7(b), this could be regarded as a component of the Variable O&M cost. However, as the emission cost is a result of burning the fuel and the cost is influenced by the heat rate, we consider it more useful to include this cost as part of the fuel cost in $/GJ. The emissions associated with the start-up fuel consumption are also included as part of the fuel cost.

For information, SKM MMA has also calculated the Energy Price Limits for the 2013/14 financial year without a carbon price, as presented in Appendix F.

[21] The change in loss factor from 2011/12 to 2012/13 was 0.097% which had not material effect on the assessed Energy Price Limits as they were rounded to the nearest integer value.

When the carbon price is applied to the emissions from the power station, there will be impacts arising from the combustion and fugitive carbon emissions associated with burning the fuel. Gas and distillate have different emission intensities. Therefore there will be a separate impact for each fuel. SKM MMA has made the following assumptions:

1) The carbon price to apply from 1 July 2013 will be $24.15/tCO_2e$ and it will apply for the whole financial year.

2) The dispatch of the gas fired peaking plants will not be materially influenced by the carbon price. This assumption may become incorrect as carbon price increases further. It is expected to be a robust assumption in 2013/14 as the carbon price is not expected to be great enough to change the role of the 40 MW gas turbines considered in this review. The market dispatch data did not show any obvious change in dispatch patterns for the Pinjar and Parkeston peaking plants when carbon price was introduced.

For gas and distillate supplied to the peaking generators, there will be carbon emissions associated with:

1. The production of the fuel
2. The transport of the fuel
3. The combustion of the fuel

These components are discussed for each fuel in the following sub-sections. The parameters used are taken from "National Greenhouse Accounts (NGA) Factors" dated July 2012. The allowance for emissions associated with the production of gas and distillate are less clear from the user's perspective and it is likely that they would be reflected in the price of the product itself ultimately. ACIL Tasman in the gas price report has allowed 9c/GJ for the production and transport components and SKM MMA has confirmed this level of contribution as follows. The split between the contributions from gas production and gas pipeline operation have been estimated to determine differing allowances for the Dampier to Bunbury Pipeline (DBNGP) and the Gas to the Goldfields Pipeline (GGP).

### 3.5.1. Gas fired generation

The combustion of natural gas is assessed as 51.33 kg $CO_2e$/GJ from Table 2 of the NGA Factors[22].

The emissions of carbon dioxide from the production and transmission of carbon dioxide are shown in "Table 37: Scope 3 emission factors –gaseous fuels" of the National Greenhouse

[22] National Greenhouse Accounts Factors July 2012, Department of Climate Change and Energy Efficiency, Table 2, page 13

Accounts Factors[23]. It shows 4.0 kg $CO_2$e/GJ for the metro area and 3.9 kg $CO_2$e/GJ for non-metro areas. This emission rate converts to 9.66c/GJ and 9.42c/GJ respectively at $24.15/t$CO_2$e. Comparison with an estimate of the transportation cost confirms this basis as follows.

The transport of natural gas depends on pipeline distance. The relevant transmission factor is 8.72 t $CO_2$e/km of pipeline. The total emission of the DBNGP is published in the Revised Access Arrangements Spreadsheet on the ERA website for 2011 to 2015[24] as well as the estimated throughput including forward and back haul. The forecast throughput is 756.9 TJ/day in calendar year 2013 and 763.1 TJ/day in 2014. Dividing the published emissions into the throughput gives a transport emission of 1.330 kg $CO_2$e/GJ as shown in Table 3-6. This corresponds to 3.2c/GJ in 2013/14, which confirms the 3c/GJ estimated by ACIL Tasman in the Final Report on Gas Prices, as shown in Table 3-7.

- **Table 3-6 DBNGP Pipeline Emissions and Throughput**

| Calendar Year | | 2013 | 2014 | Total/Average |
|---|---|---|---|---|
| Emissions | t$CO_2$e | 364,967 | 372,647 | 737,614 |
| Throughput | TJ/day | 756.94 | 763.07 | 760.00 |
| | kgCO2e/GJ | 1.321 | 1.338 | 1.330 |

- **Table 3-7 Analysis of gas transport emissions**

| | Units | DBNGP |
|---|---|---|
| Energy Consumption | TJ | N/A |
| Gas Combustion | TJ | 356608 |
| Pipeline | t$CO_2$e | 12199 |
| Total | t$CO_2$e | 368807 |
| Transported | TJ | 277401 |
| | TJ/day | 760.00 |
| Emissions | kg$CO_2$e/GJ | 1.330 |
| c/GJ @ $24.15/t$CO_2$e | | 3.2 |

[23] Ibib, Table 37, page 69
[24] Spreadsheet at http://www.erawa.com.au/3/1086/48/dampier_to_bunbury_natural_gas_pipeline__revised_a.pm

ACIL Tasman estimated 2.5c/GJ for gas transportation on the goldfields pipeline in the Final Report. These values by difference from the estimated 9c/GJ for production and transmission leave about 6c/GJ for the producer emissions as estimated by ACIL Tasman.

SKM has adopted an overall Scope 3 emission rate at 4 kg $CO_2$e/GJ for the Pinjar power station. The emission cost is then added to the simulated fuel cost at the carbon price of \$24.15/t$CO_2$e.

The total emission factor for gas is therefore 55.33 kg $CO_2$e/GJ for Pinjar, including emissions from gas production, transport and combustion in the power station.

### 3.5.2. Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg $CO_2$e/GJ from Table 3 of the NGA Factors[25].

For distillate supplied to these peaking plants, the notional allowance for transport of distillate is 5.3 kg $CO_2$e/GJ[26]. However, there is no legislation yet in place to levy this carbon impost on heavy transport and this is not likely before 1 July 2013. We therefore apply a total emission of 69.50 kg $CO_2$e/GJ to represent the likely emission intensity of delivered distillate for power stations. The transport emission rate for distillate had been included in the calculation for the 2012 Review. It has been removed in this Review.

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25 National Greenhouse Accounts Factors July 2012, Department of Climate Change and Energy Efficiency, Diesel oil in Table 3, Page 15: 69.5 = 69.2 + 0.1 + 0.2 for the individual components

26 Ibid Table 39, Page 70.

# 4. Determination of Risk Margin

## 4.1. Overall uncertainty and expected values

The dispatch cycle costs of the dispatch of the industrial gas turbines are projected as shown in Table 4-1 using the average heat rate at minimum operating capacity.

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost. Accordingly, the lower half of the table presents the non-fuel and fuel components of the Alternative Maximum STEM Price for the distillate firing of the gas turbines, as well as parameters of the fuel price as simulated.

### 4.1.1. Assessing the cost components for distillate firing

Table 4-1 shows the resulting decomposition of the coefficients for the equation for the Alternative Maximum STEM Price that provide the 80% and 90% cumulative probability price[27].

Using the fuel and non-fuel components at the 80% probability level and a distillate price of $21.65/GJ, we calculate a cap price of $495.08/MWh versus the sampled 80% probability level of $500.79/MWh for the $21.65/GJ distillate price, when modelling the uncertainty in distillate price in the simulations. The 80% simulated value in Table 4-1 is similar to the value obtained with a fixed fuel price. The 90% probability value would be $520.83/MWh on this basis (5.2% higher).

In the case of distillate firing there is a prima facie case that the market is working competitively. The market data obtained to date shows that the 80% probability level does not undermine the market power mitigation role of the cap.

[27] The percentile values of the fuel and non-fuel components shown in Table 4-1 are provided for calculating the Alternative Maximum STEM Price. They are not the percentile values of the sampled parameters themselves. For example the 80% value of the non-fuel component in the 1000 samples was $70.376/MWh and the fuel component 80% value was 19.651 GJ/MWh for the industrial gas turbine. These are not the same values shown in Table 4-1 ($67.44/MWh and 19.752 GJ/MWh respectively) which used together calculate the 80% value of the Alternative Maximum STEM Price.

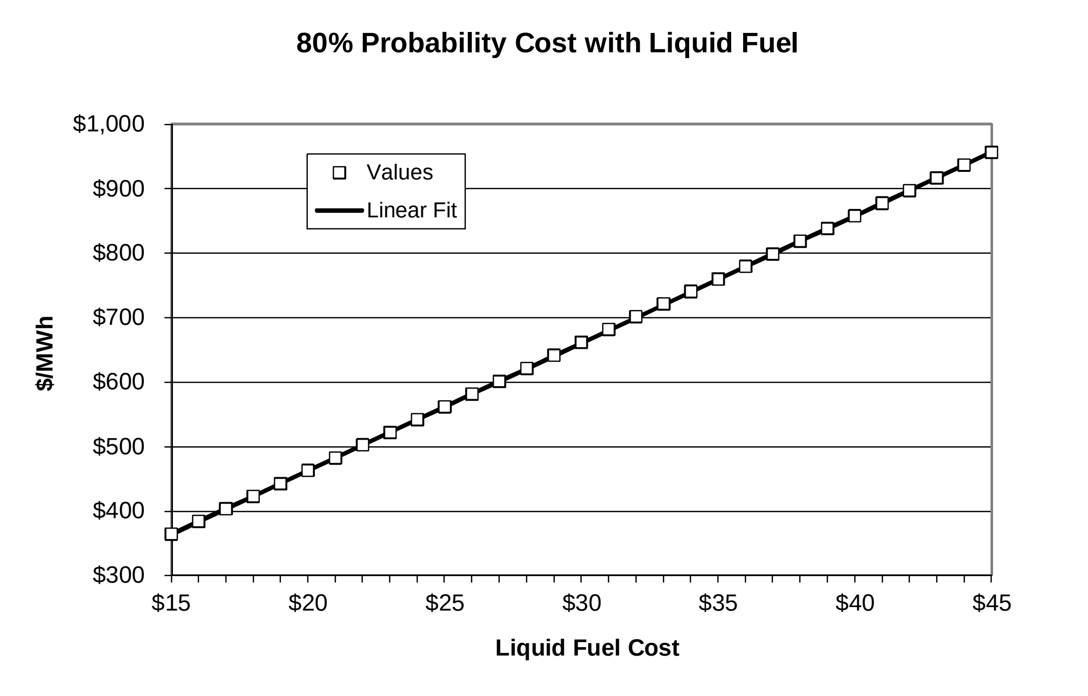
- **Table 4-1 Analysis of Industrial gas turbine dispatch cycle cost using average heat rate at minimum capacity**

| | Pinjar Gas Turbines | |
|---|---|---|
| | **Gas** | **Distillate** |
| Mean | $249.75 | $456.49 |
| 80% Percentile | $305.37 | $500.79 |
| 90% Percentile | $343.23 | $531.96 |
| 10% Percentile | $173.62 | $389.39 |
| Median | $239.73 | $450.01 |
| Maximum | $545.09 | $786.10 |
| Minimum | $104.47 | $322.81 |
| Standard Deviation | $66.69 | $59.82 |
| **Non-Fuel Component $/MWh** | | |
| Mean | | $61.73 |
| 80% Percentile | | $67.44 |
| 90% Percentile | | $79.17 |
| **Fuel Component GJ/MWh** | | |
| Mean | | 18.236 |
| 80% Percentile | | 19.752 |
| 90% Percentile | | 20.399 |
| **Equivalent Fuel Cost for % Value ($/GJ)** | | |
| Mean | | 21.647 |
| 80% Percentile | | 21.940 |
| 90% Percentile | | 22.197 |

### 4.1.2. Choosing the probability level for distillate firing

In 2010 it was noted that the STEM price did not approach the market cap during the Varanus Island incident in June 2008. In fact the STEM price never exceeded 78% of the applicable price cap. This was deemed to provide the basis for reducing the price cap to the 80% probability level since that was an extreme event and it may have indicated that our previous assessment of maximum dispatch costs for short periods with distillate firing was too high. A hypothesis which explains this outcome is that distillate firing is associated with a shortage of gas relative to demand and that the peaking generators firing distillate may then make a greater contribution to electricity supply and be run at higher duty. Accordingly, in 2010 the IMO adjusted the probability to 80% for the margin for the Alternative STEM Price, which was approved by the ERA.

■ **Figure 4-1 80% Probability generation cost with liquid fuel versus fuel cost (using average heat rate at minimum capacity)**




### 4.1.3. Choosing the probability level for gas firing

The historical STEM price distribution since January 2009 has had only 66 trading intervals (0.092% of the time) with STEM prices within 1% of the Maximum STEM Price as illustrated by the cumulative distributions in Figure 4-2. Bidding near the price cap has been reduced consistently with the increase in the Maximum STEM Price. Therefore the 80% probability level used in previous reviews is still considered suitable; it is not too low to be constraining normal bidding.

The peak of this distribution in relation to Maximum STEM Price is discussed in section 5.5.2.

The 80% probability level would give a price cap of $305/MWh which is 5.6% below the current value for the Maximum STEM Price of $323/MWh. The primary factor behind this decrease in the price cap is the reduced operation of Pinjar.

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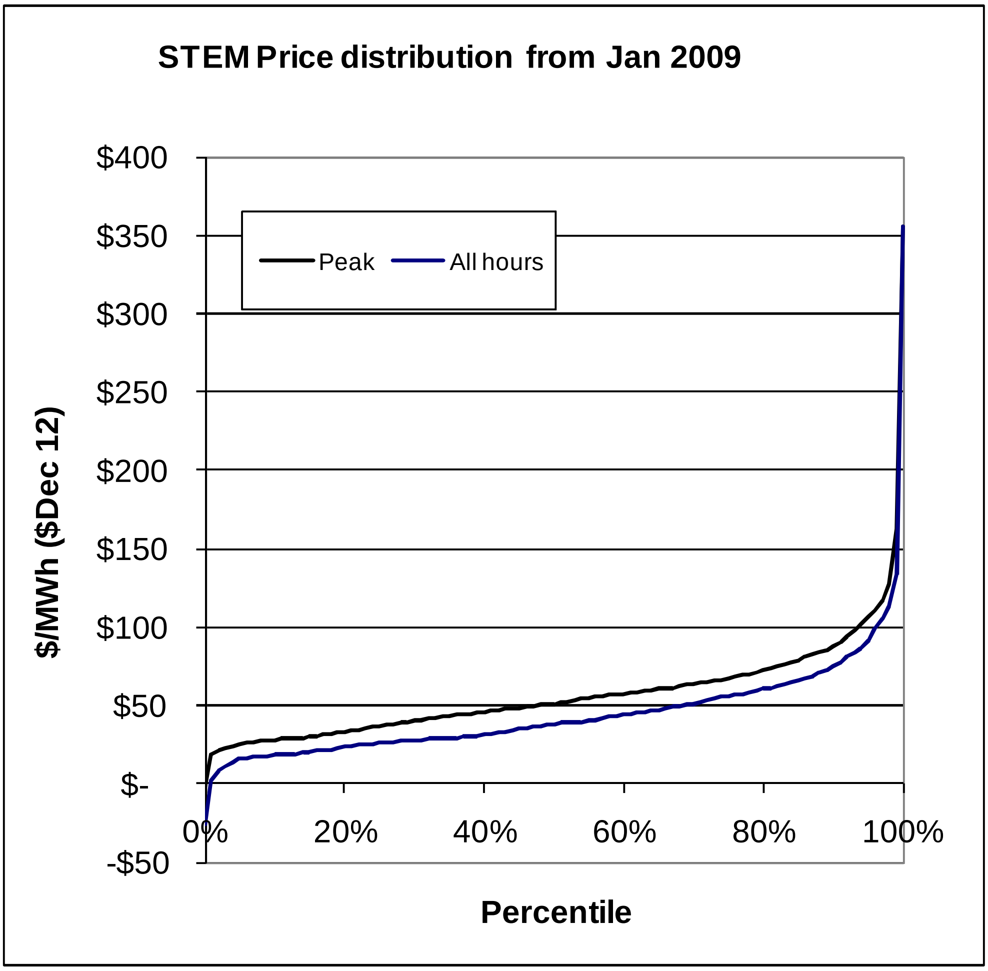
- **Figure 4-2 Cumulative Distribution of STEM Prices with Gas Firing from 1 January 2009 to 31 January 2013**




### 4.1.4. Implications for risk margin

Table 4-2 shows how the Risk Margin for the Energy Price Limits is derived from the mean values as described in clause 6.20.7(b) and the results of the statistical simulations. It shows:

- the expected values of each of the cost components that were represented in the cost simulations
- the value of the dispatch cost that would be derived from the mean values of each component and the implied Risk Margin between that average value based calculation and the proposed Energy Price Limits.
- The slight difference in mean heat rates (0.23%) as influenced by the 0.27% difference in operating heat rates (refer section 2.6) and the additional fuel for start-up (section3.2).

**Table 4-2 Illustration of components of Energy Price Limits based on mean values**

| Component | Units | Maximum STEM Price | Alternative Maximum STEM Price | Source |
|---|---|---|---|---|
| Mean Variable O&M | $/MWh | $32.04 | $32.04 | Mean of Figure 3-5 |
| Mean Heat Rate | GJ/MWh | 18.735 | 18.774 | Mean AHRN plus start-up fuel consumption. |
| Mean Fuel Cost (+ $CO_2$e cost) | $/GJ | $12.02 | $23.33 | Mean of Figure 3-2 for delivered gas price distribution plus emission cost. |
| Loss Factor | | 1.0295 | 1.0295 | Western Power Networks |
| Before Risk Margin 6.20.7(b) [28] | $/MWh | $249.86 | $456.57 | Method 6.20.7(b) |
| Risk Margin | $/MWh | $55.14 | $38.43 | By difference from Energy Price Limits |
| | % | 22.1% | 8.4% | By ratio |
| Assessed Maximum Price | $/MWh | $305.00 | $495.00 | Table 4-1 |

It should be noted that the mean and 80 percentile values for the Energy Price Limits cannot be calculated by using the corresponding mean and percentile values for the individual components due to the asymmetry of the probability distributions of the cost components. It may be noted that the "Before Risk Margin" in Table 4-2 is significantly higher than the expected value of the dispatch cycle cost due to these asymmetries.

### 4.1.5. Summary of probability analysis

In summary, SKM MMA has selected the 80% probability as being a suitable compromise for the basis for the Maximum STEM Price having regard to the need for market power mitigation. The 80% probability level criterion is also applied to the Alternative Maximum STEM Price. These measures provide a Risk Margin for clause 6.20.7(b) of 22.1% (Refer Table 4-2) for the Maximum STEM Price and 8.4% for the Alternative Maximum STEM Price and reflect the uncertainties in the analysis.

[28] Mean values have been rounded for the purpose of this calculation.

# 5. RESULTS

## 5.1. Maximum STEM Price

The IMO is obligated to apply the statistical method using the average of the heat rates at minimum capacity in recognition that the Market Rules specify how the heat rates should be applied.

In the following discussion, the values have been rounded to the nearest $1/MWh.

The Maximum STEM Price is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less. Using the average heat rate at the minimum capacity the Maximum STEM Price would yield a value of $305/MWh.

### 5.1.1. Coverage

It must be recognised that only short run times from 0.5 to 6 hours have been applied in formulating the distributions. This arrangement therefore covers a high proportion of dispatch cycles represented in the analysis, as shown in Table 5-1 which shows the results of a calculation which estimates the proportion of dispatch events that would be expected to be covered by the Maximum STEM Price.

- **Table 5-1 Coverage of Maximum STEM Price for Pinjar**

| Dispatch: | Historical from Jan 2009 (80 percentile) |
|---|---|
| Proportion of dispatch cycles less than 6 hours | 51.5% |
| Proportion of 6 hourly dispatch cycles covered by Maximum STEM Price (by simulation) | 79.8% |
| Proportion of dispatch cycles covered by Maximum STEM Price | 89.6% |

Taking into account the distribution of run-times, it is estimated that at least 89% of gas fired run-time events would have a dispatch cycle cost less than the proposed Maximum STEM Price, based on the mathematical representation of uncertainties included in this analysis and using historical dispatch characteristics.

## 5.2. Alternative Maximum STEM Price

The IMO is obligated to apply the method using the average heat rate at minimum capacity in recognition that the Market Rules specify how the heat rates should be applied.

In the following discussion, the values have been rounded to the nearest $1/MWh.

The Alternative Maximum STEM Price is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less. Using the average heat rate at the minimum capacity the Alternative Maximum STEM Price would be $495/MWh at a distillate price of $21.65/GJ. These are based on the industrial type gas turbine.

## 5.3. Price Components

The Market Rules specify the components that are used to calculate the Energy Price Limits and these have been applied in a statistical simulation. Table 4-2 on page 52 summarises the expected values of the various components and the Risk Margin values that are required under paragraphs (i) to (v) of clause 6.20.7(b) so that the resulting calculation will provide the assessed Energy Price Limits.

## 5.4. Source of change in the Energy Price Limits

To illustrate the sources of change in the Energy Price Limits, a series of studies was developed with progressive changes in the input parameters from the current parameters to those which were applied in the 2012 Review of Energy Price Limits. In each case the 1000 simulations were conducted with the same sets of random inputs except where distribution parameters were changed. In such cases, the 1000 sampled input values were taken from the analysis used in the 2012 Energy Price Limits review. This ensures that the impact of random sampling error on the assessed changes is minimised. The value of the dispatch cycle cost was taken which exceeded 800 (80%) of the 1000 samples.

Not all combinations of old and new inputs were evaluated. The sequence from new parameters back to old parameter values was developed in the order of:

1. The 2013 Review case
2. The 2012/13 Carbon price of $23/tCO$_2$e applied
3. Previous emission factors applied for gas pipeline and distillate transport
4. Previous dispatch patterns restored
5. Previous operating and maintenance costs restored
6. Previous start-up fuel consumption applied for liquid firing
7. Previous loss factor applied
8. Previous distillate cost applied
9. Previous gas transport cost distribution applied
10. Previous gas commodity cost distribution applied

11. The calculation of the 2012 Maximum STEM Price based on the 80% probability of coverage of the dispatch cycle cost.

### 5.4.1. Change in the Maximum STEM Price

Table 5-2 provides an analysis of the specific changes to show the changes in the Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2013 analysis to convert it back to the 2012 analysis.

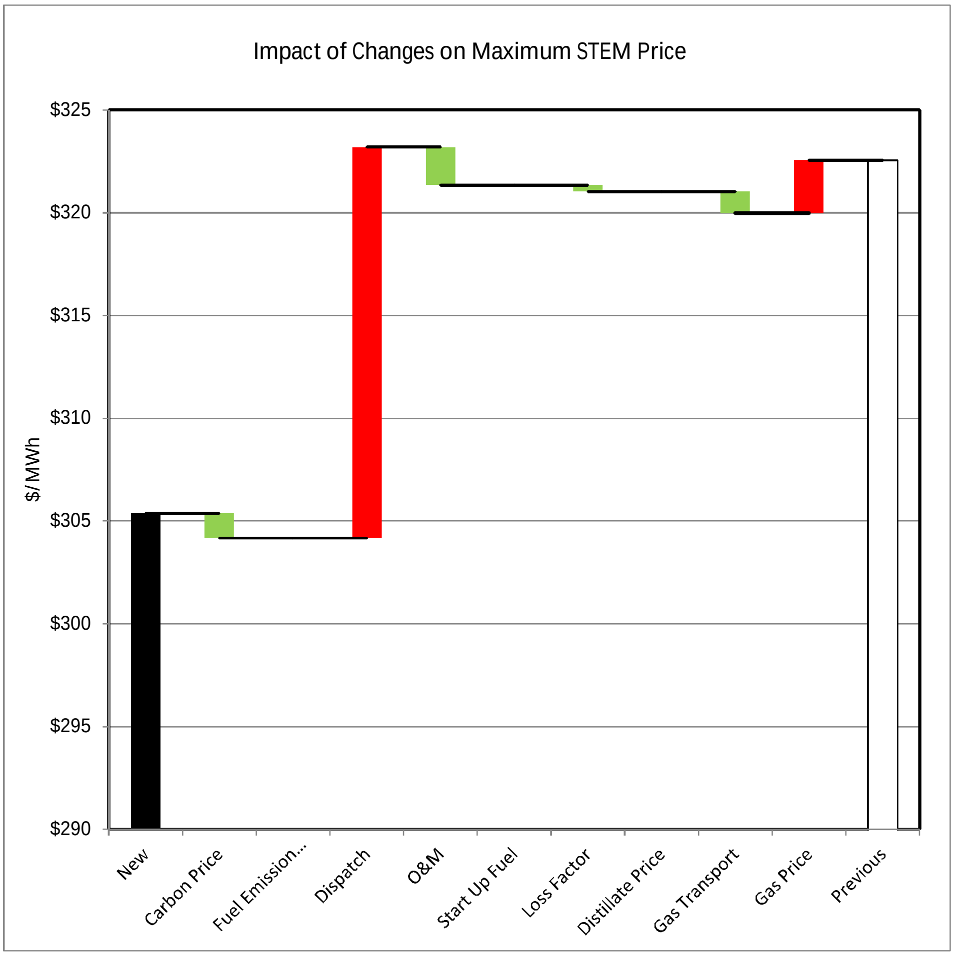
- **Table 5-2 Analysis of changes to form the Waterfall Diagram for the Maximum STEM Price**

| Step | Label in Chart | Changes | Parameters Affected (Appendix B) |
|---|---|---|---|
| 1 | New | The basis for the 2013 Energy Price Limits | |
| 2 | Carbon Price | Apply the 2012/13 carbon price of \$23/tCO2e to Case 1 | CP |
| 3 | Emission factors | Revert to the 2012 Review values for distillate by restoring an emission cost for distillate transport (section 3.5.2). | FER |
| 4 | New Historical Dispatch Patterns | Capacity, run-times and dispatch cycle capacity factor based on the data from 1 January 2008 to 3 February 2012 replaces the data from 1 January 2009 to 31 January 2013. | CAP, CF, RH, and hence MPR |
| 5 | O&M Parameters | The O&M costs for the industrial gas turbines were replaced with the 2012 values (reversing CPI and exchange rate adjustments). | VHC, SUC |
| 6 | Start-up Fuel Consumption for Liquid Firing | Reduced the premium from 5% to 0.27% consistent with that used for the average heat rate at minimum capacity | SUFC |
| 7 | Loss Factor | Restore loss factor to 2011/12 | LF |

| Step | Label in Chart | Changes | Parameters Affected (Appendix B) |
|---|---|---|---|
| 8 | Distillate Price | Distillate price was changed from \$21.65/GJ to \$23.62/GJ | VFC for distillate (gas price cap altered for Maximum STEM Price) |
| 9 | Gas Transport | The gas transport cost was replaced with the distributions used in the 2012 Review | VFTC, FT |
| 10 | Gas Price | The spot gas commodity cost distribution was replaced with the distribution that applied in the 2012 Review. | VFC (gas) |
| 11 | Old | The calculation of the Maximum STEM Price based on the 2012 parameters. | |

Figure 5-1 and Table 5-3 show the relative contribution of the various changes to the Maximum STEM Price since the 2012 review. The major changes have been caused by the reduced duty on Pinjar. The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Figure 5-1.

- **Figure 5-1 Impact of factors on the change in the Maximum STEM Price**




- **Table 5-3 Impact of factors on the change in the Maximum STEM Price**

| Factor | Impact $/MWh |
|---|---|
| Carbon Price | $1.20 |
| Fuel Emission Rates | $0.00 |
| Dispatch | -$19.03 |
| O&M | $1.86 |
| Start-up fuel consumption | $0.00 |
| 0Loss Factor | $0.31 |
| Distillate Price | $0.00 |
| Gas Transport | $1.05 |
| Gas Price | -$2.58 |

### 5.4.2. Change in Alternative Maximum STEM Price

Table 5-5 provides an analysis of the specific changes to show the changes in the Alternative Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2013 analysis to convert it back to the 2012 analysis.

Figure 5-2 and Table 5-5 show the relative contribution of the various changes to the Alternative Maximum STEM Price since the 2012 review. The major changes have been caused by the reduced operation of Pinjar and the lower distillate price. The relative contributions to the change in the Alternative Maximum STEM Price are illustrated in the waterfall diagram in Figure 5-2.

- **Table 5-4 Analysis of changes to form the Waterfall Diagram for the Alternative Maximum STEM Price**

| Step | Label in Chart | Changes | Parameters Affected (Appendix B) |
|---|---|---|---|
| 1 | New | The basis for the 2013 Energy Price Limits | |
| 2 | Carbon Price | Carbon Price restored to the 2012/13 value of $23/tCO_2e$ | CP |
| 3 | Emission factors | Revert to the 2012 Review values for distillate by restoring an emission cost for distillate transport (section 3.5.2). | FER |
| 4 | New Historical Dispatch Patterns | Capacity, run-times and dispatch cycle capacity factor based on the data from 1 January 2008 to 3 February 2012 replaces the data from 1 January 2009 to 31 January 2013. | CAP, CF, RH, and hence MPR |
| 5 | O&M Parameters | The O&M costs for the industrial gas turbines were replaced with the 2012 values (reversing CPI and exchange rate adjustments). | VHC, SUC |

| Step | Label in Chart | Changes | Parameters Affected (Appendix B) |
|---|---|---|---|
| 6 | Start-up Fuel Consumption for Liquid Firing | Reduced the premium from 5% to 0.27% consistent with that used for the average heat rate at minimum capacity | SUFC |
| 7 | Loss Factor | Restore loss factor to 2011/12 | LF |
| 8 | Distillate Price | Distillate price was changed from $21.65/GJ to $23.62/GJ | VFC (distillate) |
| 9 | Gas Transport (No effect) | The gas transport cost was replaced with the distributions used in the 2012 Review | VFTC,  FT |
| 10 | Gas Price (No effect) | The spot gas commodity cost distribution was replaced with the distribution that applied in the 2012 Review. | VFC (gas) |
| 11 | Old | The calculation of the Maximum STEM Price based on the 2012 parameters. | |

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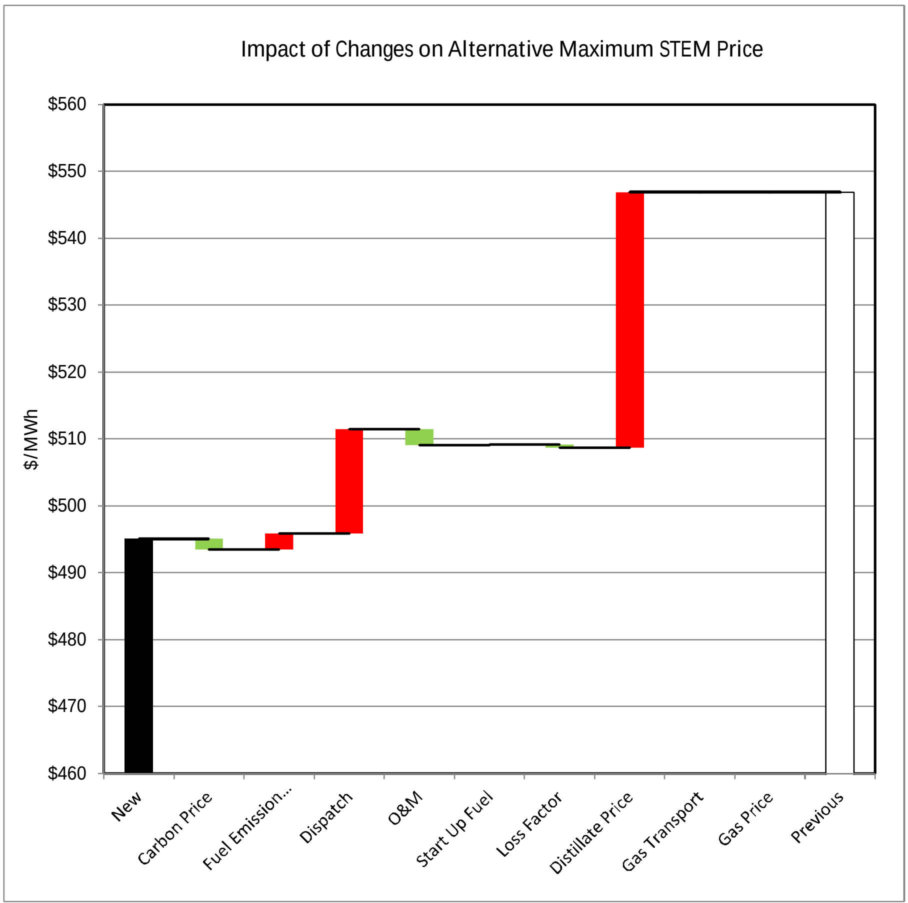
- **Figure 5-2 Impact of factors on the change in the Alternative Maximum STEM Price**




- **Table 5-5 Impact of factors on the change in the Alternative Maximum STEM Price**

| Factor | Impact $/MWh |
|---|---|
| Carbon Price | $1.59 |
| Fuel Emission Rates | -$2.43 |
| Dispatch | -$15.58 |
| O&M | $2.42 |
| Start-up Fuel Consumption | -$0.12 |
| Loss Factor | $0.49 |
| Distillate Price | -$38.23 |
| Gas Transport | $0.00 |
| Gas Price | $0.00 |

## 5.5. Cross checking of Results

### 5.5.1. Cross checking dispatch cycle costs with heat rate based on market dispatch

Since Rule Change RC_2008_07, the Market Rules refer to the use of the average heat rate at minimum capacity. This has been accepted to ensure that the Energy Price Limits would not restrict the most inefficient practical operation of the gas turbines - that is with loading at the minimum generation level. This has the effect of providing additional margin above the likely actual costs of peaking operation. In this study and previously, SKM MMA has also calculated the expected costs using minimum and maximum capacities and associated heat rates and typical dispatch profiles to assess the variation of average heat rate for dispatch cycles of different duration and capacity factor. This process is described as the “market dispatch cycle cost method” and the method and results are presented in Appendix E. This may be used to assess the probability that the Energy Price Limits will exceed actual dispatch cycle costs.

Table 5-6 shows a tabulation of the mean values of the dispatch cycle cost using the average heat rate at minimum capacity as well as the dispatch cycle heat rate method. The results are quite similar, with potential for slight over-estimation of the Alternative Maximum STEM Price by using the heat rate at minimum value. For the Maximum STEM Price, the values are $2/MWh higher after rounding using the dispatch cycle method.

- **Table 5-6 Energy Price Limits using Average Heat rate at Minimum Capacity or Market Based Dispatch**

| | Maximum STEM Price | | Alternative Maximum STEM Price | |
|---|---|---|---|---|
| **Mean Value** | **Average Heat rate at Minimum Capacity** | **Dispatch Cycle Method** | **Average Heat rate at Minimum Capacity** | **Dispatch Cycle Method** |
| Mean value | 249.75 | 250.49 | 456.49 | 458.50 |
| 80% POE | 305.00 | 307.00 | 495.00 | 492.00 |
| Margin over Expected Value (Dispatch Cycle Method) | 21.8% | 22.6% | 8.0% | 7.3% |

The difference between the proposed Energy Price Limits and the dispatch cycle costs based on dispatch cycle heat rate modelling for Pinjar is about 7.3% of the expected costs for distillate firing and about 22.6% for gas firing[29]. That the values are similar for the Maximum STEM Price reflects a higher number of short dispatch cycles in the historical data, even though the average run time has been increasing for Pinjar. Thus the dispatch cycle cost method is calculating an effective heat rate commensurate with the average heat rate at minimum capacity at the 80% probability of coverage.

### 5.5.2. Cross checking previous Energy Price Limits against actual market data

The review has considered the historical pattern of STEM and the Marginal Cost Administered Price (MCAP) and its subsequent replacement with the Balancing Price on 1 July 2012. The purpose was to monitor the basis for applying a margin to the cost distribution when setting a price cap. It was found that in the period from 1 January 2009 to 31 January 2013, the STEM prices were within 5% of the Maximum STEM Price about 0.1% of the time. There were no instances of the Maximum STEM Price being exceeded with the Alternative Maximum STEM taking effect. This is illustrated in Figure 5-3 and Table 5-7. The MCAP and Balancing Price have been within 5% of the Maximum STEM Price only about 0.29% of the time.

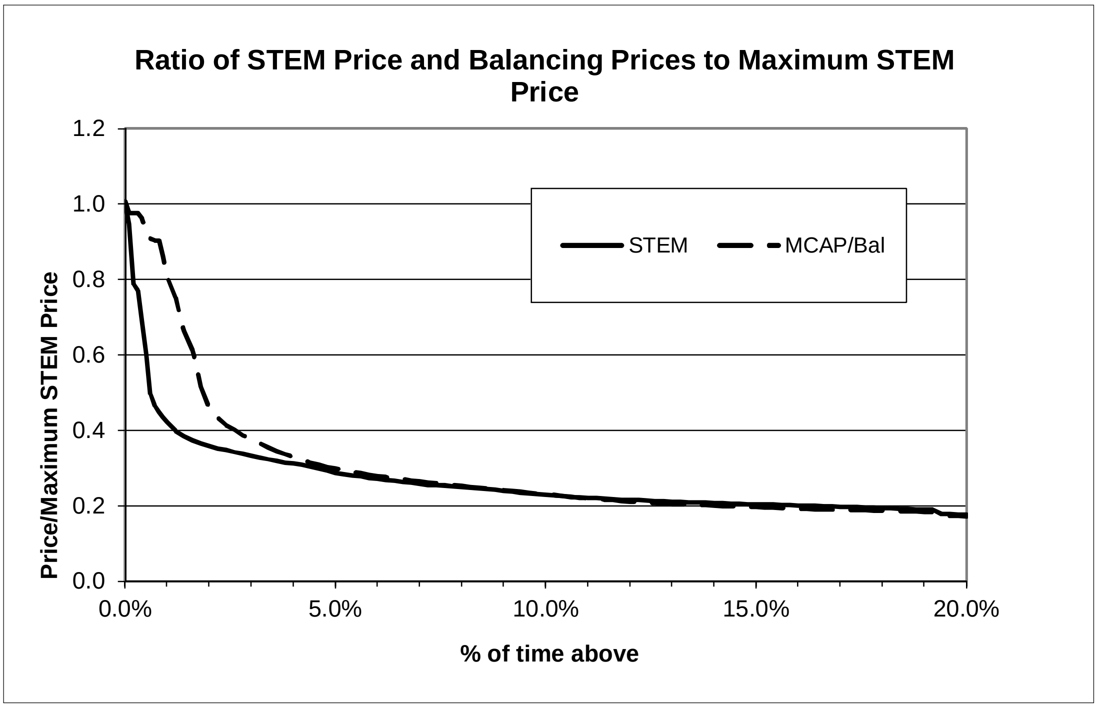
- **Table 5-7 Analysis of STEM Price and MCAP relative to Energy Price Limits**

| From 1 July 2008 to 31 January 2012 | Duration of STEM within 5% of Maximum STEM Price | Minimum proximity to Alternative Maximum STEM Price when above Maximum STEM Price |
|---|---|---|
| STEM Price | 0.10% | N/A |
| MCAP | 0.29% | N/A |

The STEM prices during and following the 2008 Varanus Island incident did not approach the Alternative Maximum STEM Price. During the February/March 2011 Varanus Island incident, the STEM Price reached $250/MWh which was well below the price limit of

[29] Table 5-6 compares the proposed price caps with the expected average dispatch cycle cost and shows the margins as a ratio of the expected average dispatch cycle cost, rather than the cost calculated by clause 6.20.7(b). The use of the average heat rate at minimum produces a slightly higher Maximum STEM Price due to the assumption about operation at minimum stable capacity which is not fully reflected in historical dispatch. The difference is immaterial.

▪ **Figure 5-3 Ratio of STEM Price and MCAP/Balancing Price to Maximum STEM Price since 1 January 2010**




$336/MWh at the time. However the MCAP reached the Maximum STEM Price for 26 trading intervals due to additional costs for balancing. The duration of the capped price was typically 1 to 4 trading intervals at a time which is consistent with the model framework which is based on the range up to 12 trading intervals.

This shows that the current prices caps are not constraining the market and have been at an appropriate level having regard to prevailing operating costs. The foregoing update to the cost analysis shows that they may be adjusted as proposed without adverse effect on the market.

# 6. PUBLIC CONSULTATION

A Draft Report version 0.6 was published for public consultation. One written submission was received from Community Electricity which is a member of the Market Advisory Committee. The response was supportive of the change to the Energy Price Limits as quoted from the submission:

> *"Community supports the draft report and in particular the proposed values for the Maximum STEM Price and Alternative Maximum STEM Price. We also welcome the significant reduction in "Pinjar starts" due to the commissioning of Verve Energy's High Efficiency Gas Turbines and the consequent reduction in the Maximum STEM Price.*
>
> *The Energy Price Limits are a central feature of the Wholesale Electricity Market and we support the relatively low levels and continuity with previous years"*

Therefore, it is concluded that there is no need to make further changes from the published Draft Report.

# 7. VARIATION TO THE MARKET RULES

## 7.1. Cost Calculation Methodology

Clause 6.20.7(b) of the Market Rules could be better expressed to describe the process of defining probability distributions of cost variables and combining them using a formula including explicit consideration of start-up costs to calculate a probability distribution of the dispatch cycle cost in $ per MWh of energy produced. The current method can be accommodated within the current clause 6.20.7(b) as set out in this report, but it would be more transparent if the clause were amended to more clearly explain the accepted practice. The rule change could also include provision for the minimum capacity to be varied according to observed dispatch patterns, with corresponding change in the average heat rate when calculating the dispatch cycle cost.

## 7.2. Gas Oil Price Basis

The Market Rules refer to Singapore Gas Oil (0.5% sulphur) as the basis for adjusting the Alternative Maximum STEM Price. However the production of distillate for power generation is based on 10 ppm impurity distillate and therefore it is proposed that clause 6.20.3 of the Market Rules be amended to refer to 10 ppm distillate instead of 0.5% sulphur as the basis for ongoing adjustment of the Alternative Maximum STEM Price. SKM MMA notes that this change does not affect the analysis in this year’s report.

# 8. CONCLUSIONS

The analysis of the costs of short term running in the SWIS has confirmed the need to decrease values on 1 July 2013 from those that apply currently. From 1 July 2013 it is proposed that:

- The Maximum STEM Price should be $305/MWh, and
- The Alternative Maximum STEM Price should be $67.44/MWh + 19.752 multiplied by the delivered distillate fuel cost in $/GJ.

At $21.65/GJ distillate price the proposed Alternative Maximum STEM Price is $495/MWh.

The most significant influences on the Alternative Maximum STEM Price have been the reduction in fuel price and the reduced number of starts per year for Pinjar. The reduced start frequency for Pinjar reduces the present value start cost which results in a lower assessed O&M cost per MWh of dispatch.

The decrease in the Maximum STEM Price since last year's assessment has been primarily due to the reduced number of starts per year for the Pinjar machines. The cost per start has reduced by 36% due to the reduced frequency of starts. This flows through to the variable O&M term in the dispatch cycle cost calculation. The other changes in operating costs and fuel costs have had a slight positive impact on the Maximum STEM Price of $1.90/MWh.

Table 8-1 summarises the prices that have applied since October 2010 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar as more precise values are not warranted by the accuracy of the analysis.

**Table 8-1 Summary of price caps**

| No. | Method | Maximum STEM Price ($/MWh) | Alternative Maximum STEM Price ($/MWh) | Comment |
|---|---|---|---|---|
| 1 | Published Prices from 1 October 2010 | $336 | $446 | From IMO website |
| 2 | Published Prices from 1 October 2011 | $314 | $524 | From IMO website |
| 3 | Published Prices from 1 June 2012 | $314 | $571 | From IMO website |
| 4 | Published Prices from 1 May 2013 | $323 | $523 | From IMO website |

| No. | Method | Maximum STEM Price ($/MWh) | Alternative Maximum STEM Price ($/MWh) | Comment |
|---|---|---|---|---|
| 5 | Using estimated costs and dispatch modelling to derive the price | $307 | $492 | Heat rates based on dispatch modelling based on $21.65/GJ for distillate. |
| 6 | Using average heat rates at minimum capacities to derive the proposed prices to apply from 1 July 2013 | $305 | $495 | Heat rates were varied but not based on dispatch modelling. Start-up fuel consumption is included. Based on $21.65/GJ for distillate. |
| 7 | Probability level as Risk Margin basis | 80% | 80% | |

Notes:

(1) The fifth row shows the price caps that would apply if the analysis were based on the detailed analysis of operating costs including using the heat rates reflective of the dispatch profile and the 80% probability levels for Maximum STEM Price and Alternative Maximum STEM Price.

(2) The sixth row shows, the risk adjusted costs that would apply if the cost analysis is conducted solely using the average heat rate at minimum capacity. Start-up fuel consumption was included. As required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2013 based on a projected delivered wholesale distillate price of $1.217/litre excluding GST to Pinjar.

(3) In the seventh row, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps.

# Appendix A MARKET RULES RELATED TO MAXIMUM PRICE REVIEW

This appendix lists the Market Rules that determine the review of maximum prices in the WEM. The relevant Market Rule clauses are provided below:

6.20.6. The IMO must annually review the appropriateness of the value of the Maximum STEM Price and the Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 the IMO:

(a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on the IMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM, where this is to be based on the IMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

(b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

(1 + Risk Margin ) x (Variable O&M +(Heat Rate x Fuel Cost))/Loss Factor

Where

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction; ;

ii. Variable O&M is the mean variable operating and maintenance costs for a 40 MW open cycle gas turbine generating station expressed in $/MWh; and include, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity based on a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for the generator relative to the Reference Node.

Where the IMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.9. In conducting the review required by clause 6.20.6 the IMO must prepare a draft report describing how it has arrived at a proposed revised value of an Energy Price Limit. The draft report must also include details of how the IMO determined the appropriate values to apply for the factors described in clause 6.20.7(b)(i) to (v). The IMO must publish the draft report on the Market Web-Site and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised value to an Energy Price Limit in accordance with clause 6.20.10, the IMO may publish a request for further submissions on the Market Web Site. Where the IMO publishes a request for further submission in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. After considering the submissions on the draft report described in clause 6.20.9, and any submissions received under clause 6.20.9A, the IMO must propose a final revised value for any proposed change to an Energy Price Limit and submit those values and its final report, including any submissions received, to the Economic Regulation Authority for approval.

6.20.11. A proposed revised value for any Energy Price Limit replaces the previous value after:

(a) the Economic Regulation Authority has approved that value in accordance with clause 2.26; and

(b) the IMO has posted a notice on the Market Web Site of the new value of the applicable Energy Price Limit,

with effect from the time specified in the IMO's notice.

# Appendix B FORMULATION OF THE MAXIMUM STEM PRICE

## B.1 Formulation of the Energy Price Limits

The following represents the formulae used to model the formula in clause 6.20.7(b) of the Market Rules, excluding the Risk Margin factor, broken down into the full set of sub components. It is the formulae below that are used to calculate the 1000 plus samples used to create the probability curve for the Energy Price Limits. The primary formula below includes the start-up fuel cost, the start operating cost and the fuel cost components, and emissions.

Cost = (VHC * RH / MPR + AHRN * (VFTC+ (FT + VFC * FSR )/VFTCF + FER * CP) +( SUC + SUFC * ( VFTC + (FT + VFC * FSR )/VFTCF + FER * CP))/MPR)/ LF

Where:

Cost is the sampled estimate of the average marginal cost of a dispatch cycle including the start-up costs on the basis that the start-up costs are part of the cost associated with the decision to start operating a unit.

VHC is the variable hourly running cost when maintenance costs are based on running hours;

RH is the running hours per dispatch cycle based on a sampled distribution derived from market observations of dispatch. This distribution is confidential and is not included in this report, apart from the average of 34.1 hours for Parkeston shown in Table D- 3;

MPR is the MWh generated per run based on a sampled distribution derived from market observations and derived as a function of run-time. This distribution is confidential and is not included in this report, apart from the average value of 794.9 MWh shown in Table D- 3;

MPR = CAP * RH * CF

AHRN is the average heat rate at minimum capacity in GJ/MWh sent out (or a dispatch based calculation of average heat rate when that alternative method was applied);

VFTC is the variable fuel transport cost in $/GJ;

FT is the fixed fuel transport cost in $/GJ;

VFC is the variable fuel cost in $/GJ in the range $2/GJ to $24/GJ or lower if the break even price with distillate is lower;

FSR is the reference spot gas supply capacity factor (taken as 100%);

VFTCF is the spot gas supply daily capacity factor as modelled as a probability distribution between 60% and 100%;

FER is the fuel emission rate in $tCO_2e$ per GJ for the delivered fuel including the components expected to be passed through in gas supply and transport.

CP is the carbon price in $/$tCO_2e$

SUC is the cost per start ($/start) when maintenance costs depend on the number of starts per year using the time discount formulation:

CPS(i) = X(i)/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

SUC = Sum [CPS(i)]

Where:

CPS(i) is the cost per start for each maintenance stage (i)

Sum [CPS(i)] is the summation of the values of CPS(i) for all of the maintenance stages (i) in the full cycle.

X(i) is the maintenance expenditure for each maintenance stage

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the sampled number of starts per year;

Log is the natural logarithm.

SUFC is the start-up fuel consumption to get the plant up to minimum stable generation in GJ;

CAP is the plant sent-out capacity in MW. The capacity is derived from a distribution of maximum output of the generator units which is derived from market data.

CF is the capacity factor of the dispatch cycle derived from the capacity factor versus run-time based on a regression function derived from historical operating data since January 2009

LF is the loss factor.

The variable fuel cost of gas (VFC) was capped to the price which would give the same dispatch cycle cost as the prevailing price of distillate sampled from the distillate price distribution.

The primary formula above may be split into the two components (fuel and non-fuel dependent) for the calculation of the Alternative Maximum STEM Price as follows.

The non-fuel component is based on non-fuel start-up costs, the variable O&M cost as applicable, and the emission cost:

AMSP Non-fuel Component = ((VHC * RH / MPR + SUC )/MPR + (AHRN + SUFC/MPR) * (FER * CP))/LF

The fuel dependent component for the Alternative Maximum STEM Price cost is derived from the following components:

AMSP Fuel Component = (AHRN * (VFTC+ (FT + VFC * FSR )/VFTCF) + SUFC * ( VFTC + (FT + VFC * FSR )/VFTCF )/MPR)/ LF

After removing the zero and unity terms applicable to distillate, the fuel component is:

AMSP Fuel Component = (AHRN * (VFTC+VFC ) + SUFC * ( VFTC + VFC ) )/MPR)/ LF

The effective Fuel Cost Coefficient may be derived by dividing by the delivered fuel cost (VFTC + VFC):

AMSP Fuel Cost Coefficient = (AHRN + SUFC/MPR)/LF

Note that the percentile value of these coefficients is derived from these sampled values so that the 80% value is obtained as discussed in section 4.1.1.

For the purpose of the equation defined in clause 6.20.7(b), the Fuel Price is adjusted to include the emission cost as follows:

Adjusted Fuel Cost = (VFTC+ (FT + VFC * FSR )/VFTCF + FER * CP)

The treatment of these variables as stochastic variables is summarised in Table B- 1. The means, minima and maxima and standard deviations for the heat rate (AHRN) were as derived from the dispatch cycle parameters based on the minimum capacity level. Over the 1000 samples, the normal variables were typically between ±3 standard deviations unless clipped to a small range around the mean. The sampled number of starts per year was given a minimum value of 10. The Start-up cost SUC, MPR, run times RH and plant sent-out capacity CAP and dispatch cycle capacity factor CF were derived from confidential market data. The start-up cost SUC depends on the distribution of the number of starts per year for the industrial gas turbines. The loss factor LF was as published by Western Power Networks for 2012/13. The start-up fuel consumption was based on the estimates developed by SKM MMA.

- **Table B- 1 Structure of the Stochastic Model of Cost**

| Variable | Mean/Mode | Sampled Minimum | Sampled Maximum | Standard Deviation | Distribution Type | Comment |
|---|---|---|---|---|---|---|
| VHC | 203.00 | $138 | $270 | 10% | Normal | Aero derivative - Goldfields |
| AHRN | 13.418 GJ/MWh | 11.551 | 20.395 | 0.894 * | Normal | Aero derivative – Goldfields (including variation due to minimum capacity uncertainty) |
| AHRN | 18.628 GJ/MWh | 15.398 | 26.179 | 1.589 * | Normal | Industrial – Pinjar (parameters obtained from the sampled distribution including variation due to minimum capacity uncertainty) |
| VFTC | $2.213 | $1.533 | $3.098 | $0.273 * | Truncated lognormal | Aero-derivative - Goldfields |
| VFTC | $1.795 | $1.114 | $2.680 | $0.273 * | Truncated lognormal | Industrial |
| FT | $5.49 | $5.49 | $5.49 | | None | Aero-derivative |
| FT | 0.00 | 0.00 | 0.00 | | Fixed | Industrial |

| Variable | Mean/Mode | Sampled Minimum | Sampled Maximum | Standard Deviation | Distribution Type | Comment |
|---|---|---|---|---|---|---|
| VFC | $7.94 | $2.46 | $20.73 | $2.641 * | Truncated tri-lognormal | Gas supply before break-even price capping |
| FSR | 100% | 100% | 100% | | Fixed | |
| VFTCF | 89.9% | 66% | 100% | 6.70% * | Truncated lognormal | VFTCF = 1 for distillate |
| FER | 0.05533 $tCO_2e$/GJ gas | | | | None | Gas to Pinjar |
| FER | 0.05497 $tCO_2e$/GJ gas | | | | None | Gas to Parkeston |
| FER | 0.0695 $tCO_2e$/GJ distillate | | | | None | Distillate |
| CP | $24.15/$tCO_2e$ | | | | None | |
| SUFC | 3.53 GJ | 2.400 | 4.590 | 10% | Normal | Aero-derivative |
| SUFC | 3.50 GJ | 2.376 | 4.543 | 10% | Normal | Industrial |
| SUFC | 3.54 GJ | 2.407 | 4.602 | 10% | Normal | Aero-derivative (liquid fuel) |
| SUFC | 3.51 GJ | 2.382 | 4.555 | 10% | Normal | Industrial (liquid fuel) |

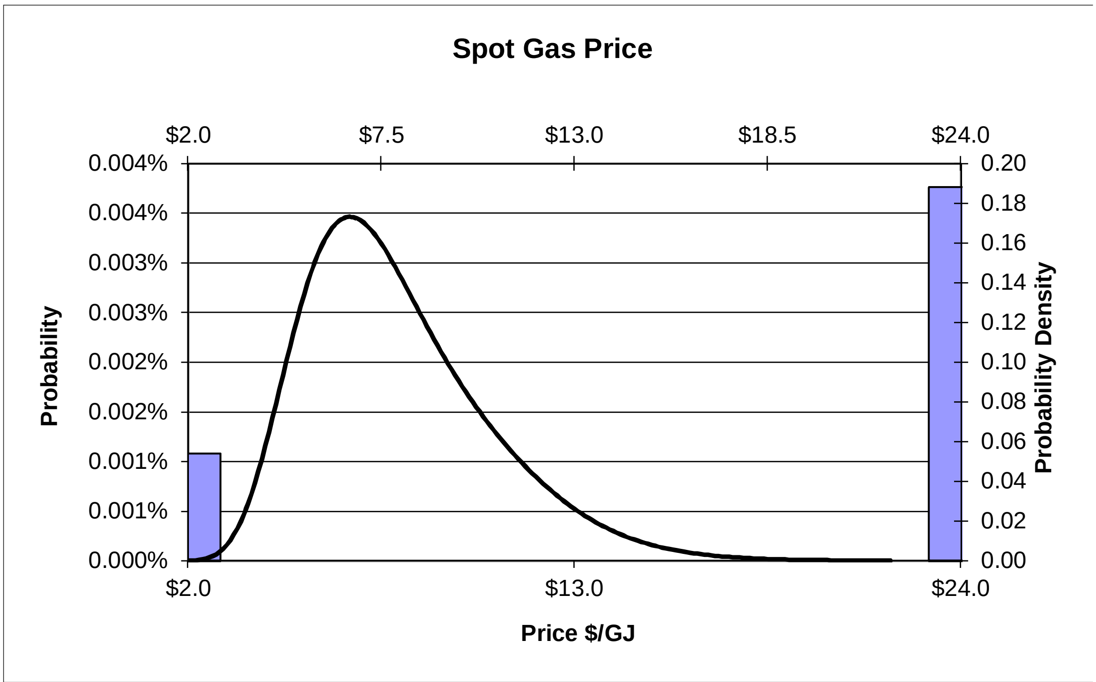
Note: * These standard deviation values refer to the values as sampled within the limited range.

# Appendix C Gas Price Distributions

## C.1 Spot gas price

Figure C- 1 shows the gas price probability distribution used to represent the spot gas price uncertainty as defined by ACIL Tasman. The distribution consists of three lognormal distributions with the parameters and weighting shown in Table C- 1. This model was derived from the simulated distribution provided by ACIL Tasman shown as a density function in Figure C- 2. The red line shows the polynomial approximation developed by ACIL Tasman. The black line shows the bi-modal lognormal distribution developed by SKM MMA, to better represent the underlying sampled data derived by ACIL Tasman. The characteristics of the sampled and fitted distributions are shown in Table C- 2.

- **Figure C- 1 Capped lognormal distribution for modelling spot gas price uncertainty**




- **Table C- 1 Parameters of spot gas price distribution developed by SKM MMA**

| Lognormal: | 1 | 2 | Composite |
|---|---|---|---|
| µ | 1.976 | 2.435 | |
| Σ | 0.304 | 0.187 | |
| Mean Value | 91% | 9% | 7.94 |
| Weight | 1.976 | 2.435 | |

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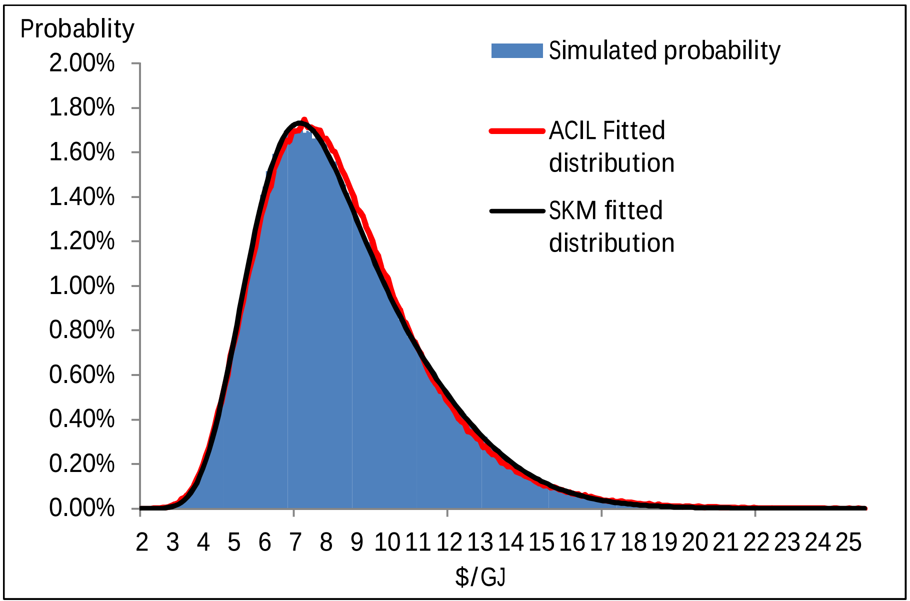
**Table C- 2 Characteristics of spot gas price distribution**

| | Mean | St Dev | Mode | 10% | 90% |
|---|---|---|---|---|---|
| Sampled | $7.99 | $2.62 | $6.48 | $5.00 | $ 11.60 |
| ACIL Fitted | $7.99 | $2.63 | $6.80 | $5.02 | $11.56 |
| SKM Fitted | $7.94 | $2.76 | $6.60 | $4.98 | $11.54 |

**Figure C- 2 Comparison of simulated and fitted distributions**



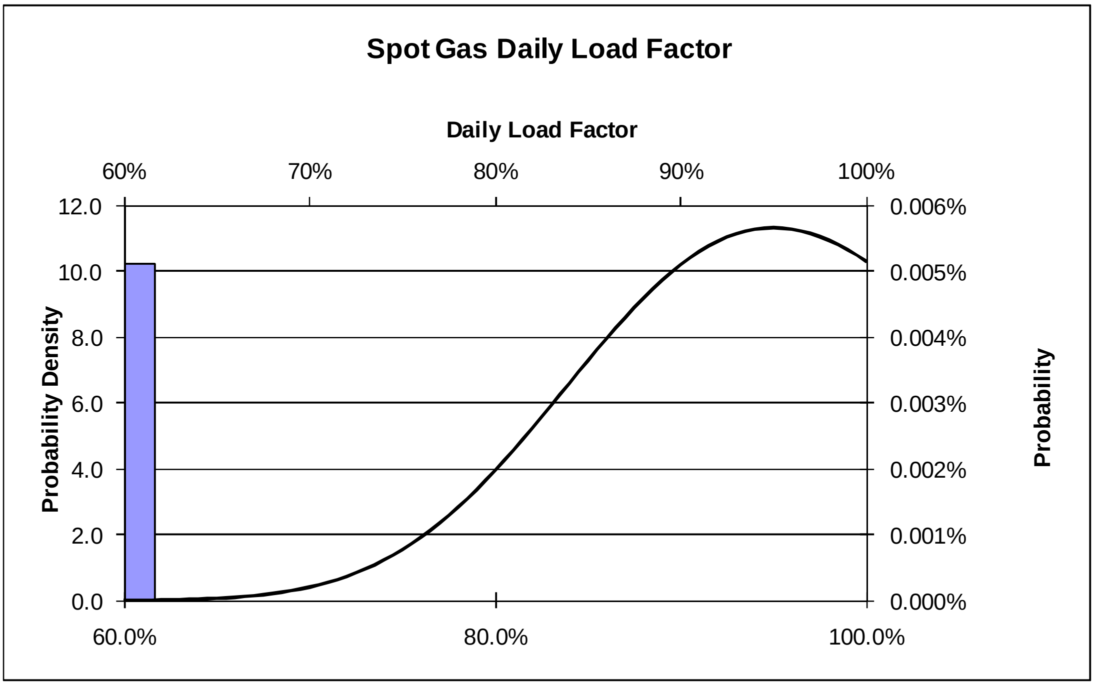

The black line in Figure C- 1 shows the continuous probability density as shown by the right hand vertical axis. The blue columns represent the probability that the gas price is at $2/GJ (0.0.001%) and $24/GJ (0.004%) when not on the continuous range. This probability is indicated by the vertical axis on the left hand side of the chart. The mode of the distribution is $6.60/GJ which is similar to the sampled distribution of $6.40/GJ [30].

## C.2 Daily gas load factor

The probability distribution used to represent the uncertainty of the daily gas supply load factor is shown in Figure C- 3. The mode of the continuous distribution is at 95% with an 80% confidence arrange between 80% and 98%. There is a 0.005% probability of a value

[30] The ACIL Tasman sampled distribution has a mode of $6.40/GJ, the lognormal approximation a mode of $6.80/GJ and the bi-modal approximation a mode of $6.60/GJ.

▪ **Figure C- 3 Capped lognormal distribution for modelling spot gas daily load factor uncertainty**




at 60%. The mean of the composite daily load factor distribution is 89.91%. This is consistent with the model provided by ACIL Tasman in the Final report.

### C.2.1 Transmission charges

For the gas transport to Perth, a lognormal distribution is recommended with the 80% confidence range being between \$1.46/GJ and \$2.15/GJ with a most likely value (mode) of \$1.735/GJ. The mean value of the transmission charge is \$1.795/GJ. SKM MMA developed the distribution shown in Figure C- 4 to represent this uncertainty in the gas transport cost.

The gas cost range was taken between \$1/GJ and \$3/GJ which is consistent with the spreadsheet provided by ACIL Tasman.

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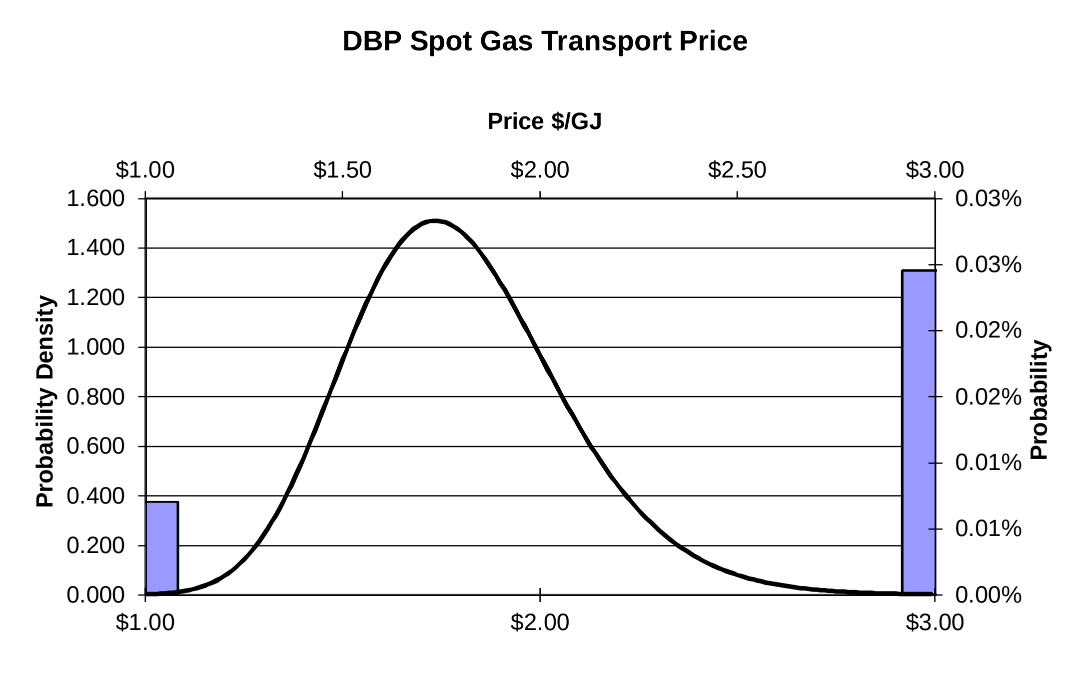
- **Figure C- 4 Capped lognormal distribution for Dampier to Bunbury Pipeline spot gas transport cost**



# Appendix D Energy Price Limits based on aero-derivative gas turbines

This appendix will present the analysis for the Parkeston gas turbines and compare it with the base calculations for Pinjar gas turbines shown in Chapters 3 and 4.

The calculations were substantially the same as for the industrial gas turbines except that:

- The gas transportation cost is supplemented by the Gas to the Goldfields Pipeline (GGP)
- The O&M cost is determined by running hours instead of starts
- There is a 43% cost penalty on the variable O&M cost for liquid firing because the aero-derivatives require more frequent maintenance when liquid fired. This arises from the Hot Rotable exchange which is required every 12,500 hours for liquid firing instead of 25,000 for gas firing.
- The transmission loss factor differs for Parkeston (1.2429)

The following sections discuss these differences in input data.

## D.1 Run times

Unlike Pinjar, there was no evidence that the frequency of starts or run times for Parkeston have materially changed since September 2012. The evidence is presented in the confidential Appendix for the IMO. Therefore the full market dispatch information from 1 January 2009 to 31 January 2013 has been used.

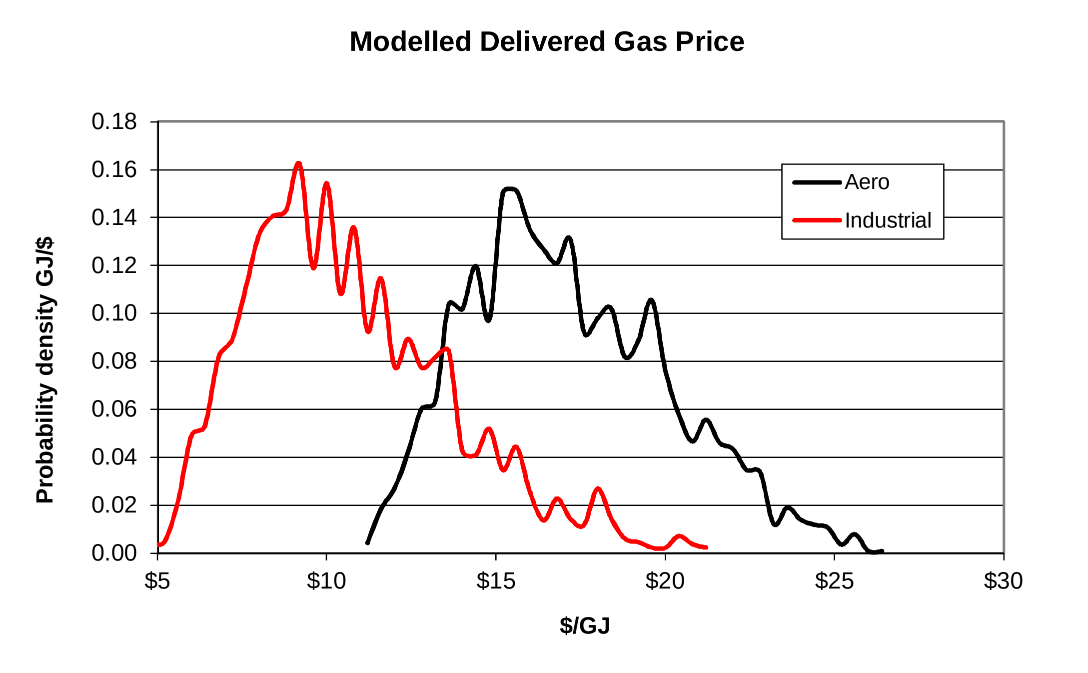
The run times of the peaking units have been analysed from the market data from 1 January 2009 to 31 January 2013. A probability density function has been derived which represents the variation in run times until 31 January 2013.

## D.2 Gas transmission to the Goldfields

Having assessed the likely conditions for spot trading of gas transmission capacity, ACIL Tasman concluded that the appropriate prices for delivery to the Goldfields from 1 July 2013 should be $5.91/GJ plus the DBNGP transport price with an 80% confidence range between $1.46/GJ and $2.15/GJ for transport to the Perth region. There is virtually no uncertainty about the price of spot transport to the Goldfields. SKM MMA has decomposed the Goldfields price into $5.49/GJ as a fixed component which is divided by the daily load factor and $0.42/GJ which is variable and unaffected by the daily gas supply load factor.

The resulting modelled delivered gas price as compared with the equivalent delivered price for the industrial gas turbines at Pinjar is shown in Figure D- 1. The modelled delivered gas price for the Goldfields region had an 80% confidence range of $13.55/GJ to $21.36/GJ with

- **Figure D- 1 Sampled probability density of delivered gas price for peaking purposes (excluding carbon price)**




- **Table D- 1 Delivered gas price for Parkeston gas turbines**

| Delivered Gas Prices as Modelled | |
|---|---|
| | **Parkeston** |
| Min | $10.75 |
| 5% | $12.85 |
| 10% | $13.55 |
| 50% | $16.78 |
| Mean | $17.12 |
| Mode | $15.60 |
| 80% | $19.72 |
| 90% | $21.35 |
| 95% | $22.47 |
| Max | $26.94 |

a mode of $15.60/GJ and a mean of $17.12/GJ. The key features of the delivered gas price for Parkeston are provided in Table D- 1.

## D.3 Distillate for the Goldfields

The Free into Store price of distillate at 138.016 Acpl for Parkeston applies after applying a road freight cost of 5.22 Acpl to Parkeston. This equates to a diesel price of $1.255/litre ex GST for Parkeston. After deducting 38.14c excise and applying a calorific value of 38.6 MJ/litre, this equates to $22.62/GJ for Parkeston.

## D.4 Start-up fuel consumption

The start-up fuel consumption for the aero-derivative gas turbines was estimated as 3.53 GJ. For liquid firing, it is 3.54 GJ.

## D.5 Aero derivative gas turbines – LM6000

The variable O&M cost for aero derivative gas turbines is based upon a maintenance contract price of $281.49/hour in March 2013 dollars as estimated and shown in the second column from the right in Table D- 2. These costs have been escalated from those used last year, as no new data could be established with confidence. The cost estimates change from last year's values was based on Australian price escalation and the change in the $US dollar exchange rate. SKM MMA has applied economic time based discounting for the major overhaul components and the logistics costs split between scheduled and unscheduled maintenance to calculate a discounted cost of $199.47/hour. This is escalated to $203/hour at December 2013. This is slightly increased from $197/hour in the 2012 Review, primarily due to price escalation.

Aero derivatives have a minimum start-up cost equivalent to about one running hour. However, under this pricing structure, this additional impost may be ignored as immaterial.

Table D- 3 shows the assessed variable O&M cost based on the historical operating regime for the aero derivative gas turbine since January 2009. The weighted average is $8.37/MWh. The variable O&M cost is more stable, so SKM MMA has not added uncertainty due to changes in starts per year or running hours.

It is considered that liquid firing of aero-derivative gas turbines doubles the frequency of the Hot Section Rotable Exchange to every 12,500 hours. This increases the assessed discounted operating cost from $199/hour to $286/hour, a 43% increase.

## D.6 Results

Table D- 4 compares the results for the aero-derivative gas turbines with the results shown above for the industrial gas turbines. It is evident that the costs remain substantially lower for the aero-derivative gas turbines.

**Table D- 2 Basis for Running Cost of Aero-derivative Gas Turbines —LM6000 (March 2013 dollars)**

| **Overhaul Type** | **Number of hours trigger point for overhauls** | **Cost per Overhaul** | **Number in Overhaul Cycle** | **Cost per cycle** | **Cost per fired hour** | Discounted Cost per fired hour |
|---|---|---|---|---|---|---|
| Preventative Maintenance | 4,000 hrs, 450 cycles or annually, whichever first | | 13.003 | $202,730 | $4.05 | $4.05 |
| Hot Section Rotable Exchange | 25,000 | $3,666,504 | 1 | $3,666,504 | $73.33 | $44.10 |
| Major Overhaul | 50,000 | $5,118,984 | 1 | $5,118,984 | $102.38 | $61.57 |
| Shipping of Parts, Travel, Living Expenses of Maintenance Personnel, Extra | | | | $1,971,972 | $39.44 | $27.46 |
| Unscheduled Maintenance | | | | $2,747,349 | $54.95 | $54.95 |
| Consumable Day-to-Day Maintenance (lube oil, air filters, etc) | | | | $366,732 | $7.33 | $7.33 |
| | | | **Total:** | $14,074,270 | $281.49 | $199.47 |

Source: SKM data sourced from manufacturers and analysis of discounted value based on 112.6 starts/year

- **Table D- 3 Assessed Variable O&M Cost for Aero Derivative Gas Turbine – LM6000**

| Aero Derivative Unit | Average Running Hours | Number of Starts / Year | Cost / Run | Average MWh per Run | Variable O&M Cost $/MWh |
|---|---|---|---|---|---|
| 1 | 42.8 | 74.1 | $8,684 | 1020.7 | $8.51 |
| 2 | 31.0 | 146.1 | $6,283 | 738.7 | $8.51 |
| 3 | 28.7 | 117.7 | $5,827 | 722.4 | $8.07 |
| **ALL UNITS** | 34.1 | 337.8 | $6,651 | 794.9 | $8.37 |

- **Table D- 4 Analysis of dispatch cycle cost using average heat rate at minimum capacity**

| Sample | Aero Derivative – LM6000 | | Industrial Gas Turbine | |
|---|---|---|---|---|
| | Gas | Distillate | Gas | Distillate |
| Mean | $208.13 | $275.54 | $249.75 | $456.49 |
| 80% Percentile | $237.70 | $296.63 | $305.37 | $500.79 |
| 90% Percentile | $257.58 | $307.30 | $343.23 | $531.96 |
| 10% Percentile | $165.05 | $242.99 | $173.62 | $389.39 |
| Median | $204.72 | $274.68 | $239.73 | $450.01 |
| Maximum | $356.94 | $393.03 | $545.09 | $786.10 |
| Minimum | $127.00 | $197.02 | $104.47 | $322.81 |
| Standard Deviation | $35.67 | $26.83 | $66.68 | $59.82 |
| **Non-Fuel Component $/MWh** | | | | |
| Mean | | $28.03 | | $61.73 |
| 80% Percentile | | $29.12 | | $67.44 |
| 90% Percentile | | $29.48 | | $79.17 |
| **Fuel Component GJ/MWh** | | | | |
| Mean | | 10.942 | | 18.236 |
| 80% Percentile | | 11.476 | | 19.752 |
| 90% Percentile | | 11.875 | | 20.399 |
| **Equivalent Fuel Cost for % Value** | | **$/GJ** | | |
| Mean | | 22.622 | | 21.647 |
| 80% Percentile | | 23.311 | | 21.940 |
| 90% Percentile | | 23.396 | | 22.197 |

# Appendix E Calculation of Maximum Prices using market dispatch to estimate heat rate impact

In selecting the appropriate Maximum STEM Price, we may consider whether we should revise the pricing model to take account of observed dispatch patterns instead of using the average heat rate at minimum operating capacity. This would require a change to the Market Rules.

## E.1 Methodology for market dispatch cycle cost method

The market dispatch cycle cost method was based on the following principles for output level during the dispatch cycle:

- The gas turbine unit would be loaded at maximum allowable rate to minimum generation level after synchronisation.
- The gas turbine would generate at no less than minimum capacity level until required to run down to zero just prior to disconnection. This would define the basis for a minimum allowable capacity factor for the dispatch cycle.
- If additional generation is required, the unit would ramp up to an intermediate level, hold that level and then run down to minimum and zero levels. The rate at which the generation would increase would be the rate that would get the unit to maximum output and then back again.
- For higher generation levels the gas turbine would ramp up to maximum output, hold at that level, and then ramp down to minimum generation.

The use of the heat rate at minimum capacity is slightly conservative relative to results that would be expected from more detailed analysis based on typical operations. However, the impact on the Maximum STEM Price assessment in this review is zero due to the rounding to the nearest $1/MWh.

## E.2 Treatment of heat rates

If we repeat the analysis of the Energy Price Limits, but develop the heat rates by using detailed dispatch modelling based on heat rate curves and probability distributions of capacity factor and maximum capacity derived from market data over the period from 1 January 2009 to 31 January 2013, with the same adjustment to frequency of unit starts. then we obtain the results shown in Table E- 1. This market dispatch cycle cost method gives slightly lower higher heat rates at the 80% level for Pinjar with the projected peaking dispatch and lower heat rates for the aero-derivative gas turbines.

Table E- 1 also shows the decomposition of the costs for distillate firing. The aero derivatives have a higher fuel cost due to their more remote location. The non-fuel and

- **Table E- 1 Analysis of dispatch cycle cost using market dispatch cycle cost method**

| Sample | Aero Derivative – LM6000 | | Industrial Gas Turbine | |
|---|---|---|---|---|
| | Gas | Distillate | Gas | Distillate |
| Mean | $193.93 | $257.09 | $250.49 | $458.50 |
| 80% Percentile | $220.13 | $275.35 | $306.55 | $499.25 |
| 90% Percentile | $239.15 | $285.00 | $344.39 | $532.40 |
| 10% Percentile | $154.68 | $230.11 | $174.34 | $392.36 |
| Median | $190.78 | $256.63 | $240.71 | $453.01 |
| Maximum | $318.69 | $332.30 | $544.71 | $758.71 |
| Minimum | $123.14 | $187.24 | $105.09 | $326.18 |
| Standard Deviation | $31.34 | $21.98 | $66.82 | $59.08 |
| **Non-Fuel Component $/MWh** | | | | |
| Mean | | $27.58 | | $61.87 |
| 80% Percentile | | $28.18 | | $68.21 |
| 90% Percentile | | $28.92 | | $75.69 |
| **Fuel Component GJ/MWh** | | | | |
| Mean | | 10.144 | | 18.321 |
| 80% Percentile | | 10.481 | | 19.589 |
| 90% Percentile | | 10.683 | | 20.383 |
| **Equivalent Fuel Cost for % Value** | | i. **$/GJ** | | |
| Mean | | 22.626 | | 21.648 |
| 80% Percentile | | 23.582 | | 22.004 |
| 90% Percentile | | 23.970 | | 22.406 |

equivalent heat rate terms for distillate firing were derived from the 80% cumulative probability values of cost versus distillate price over the range between $15/GJ and $45/GJ as explained in section 4.1.1 for the 1,000 simulated values corresponding to each individual sample of cost. Again the relationship between the sampled values and the linear regression function was excellent as shown in Figure E- 1.

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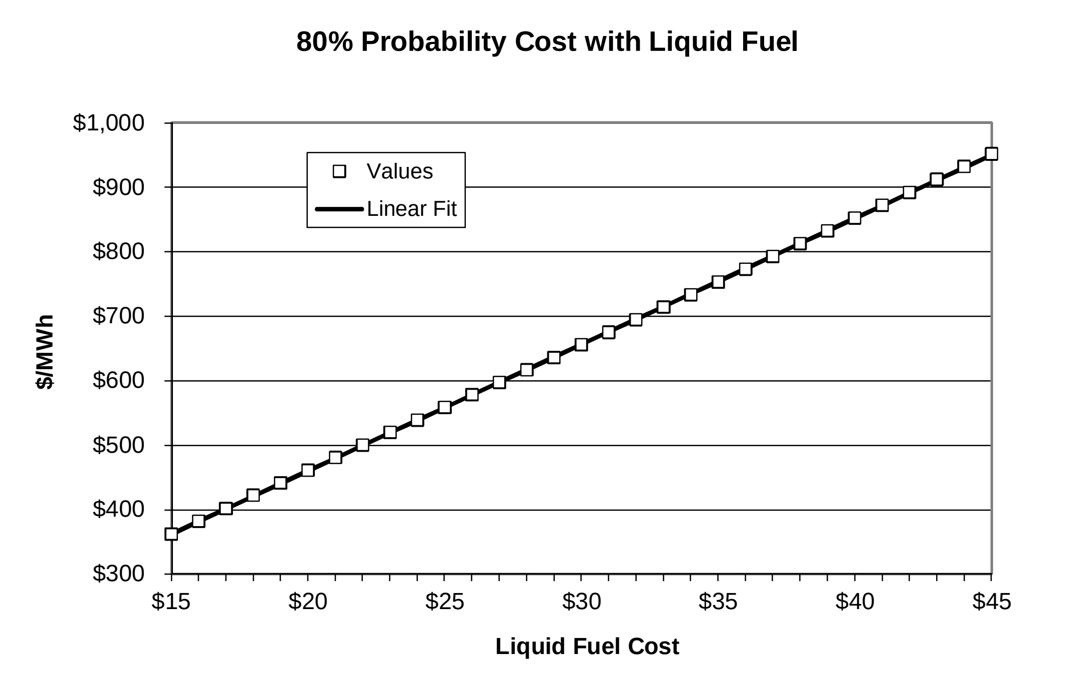
▪ **Figure E- 1 80% Probability Generation Cost with Liquid Fuel versus Fuel Cost (using market dispatch cycle cost method)**




## E.3 Implications for margin with use of market dispatch cycle cost method

If we adopt these higher values, then the margin of the price cap over the expected cost is 22.8% for the Maximum STEM Price and 7.2% for the Alternative Maximum STEM Price if based on $21.65/GJ as shown in Table E- 2 using rounded values. These margins reflect the current market and cost uncertainties[31].

Thus if we compare the assessed cost using the average heat rate at minimum capacity with the expected cost allowing for the dispatch cycles, then we obtain the comparison shown in Table E- 3. This would provide an effective margin of up to 22.0% over the expected cost, which is the same as the required heat rate assumption. The margin for the Alternative Maximum STEM Price is then 7.8% over the expected dispatch cycle cost.

[31] Note that the expected value of $460.76/MWh (rounded to $461/MWh) for the Alternative STEM Price allows for the modelled uncertainty in the distillate price.

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## Table E- 2 Margin Analysis (Market Dispatch Cycle Cost Method)

| | Maximum STEM Price | Alternative Maximum STEM Price at $21.65/GJ | |
|---|---|---|---|
| Expected Cost | $250.00 | $459.00 | $459.00 |
| Alternative Price Cap | | | $517.00 |
| Market Based Price Cap | $307.00 | $492.00 | |
| At Probability Level of | 80% | 80% | 90% |
| Margin | $57.00 | $33.00 | $58.00 |
| % Margin | 22.8% | 7.2% | 12.6% |

## Table E- 3 Margin Analysis with use of Average Heat Rate at Minimum Capacity Using Market Dispatch Cycle Cost for the Expected Cost

| | Maximum STEM Price | Alternative Maximum STEM Price at $21.65/GJ |
|---|---|---|
| Expected Cost (Market Based Dispatch Cost) | $250.00 | $459.00 |
| Proposed Price Cap (Min Heat Rate) | $305.00 | $495.00 |
| At Probability Level of | 80% | 80% |
| Margin | $55.00 | $36.00 |
| % Margin | 22.0% | 7.8% |

# Appendix F Calculation of Energy Price Limits Excluding Carbon Price

This Appendix recalculates the Energy Price Limits under the assumption that no carbon price is applicable during the 2013/14 financial year.

The revised calculation of limits is shown in Table F- 1 based on the analysis shown in Table F- 2.

The applicable Maximum STEM Price would be reduced from $305/MWh to $281/MWh.

The revised equation for the Alternative Maximum STEM Price would be

$34.36/MWh + 19.751 multiplied by the delivered distillate fuel cost in $/GJ

which at $21.65/GJ would give a revised Alternative Maximum STEM Price of $462/MWh, instead of $495/MWh.

- **Table F- 1 Components of Energy Price Limits based on mean values (without a carbon price)**

| Component | Units | Maximum STEM Price | Alternative Maximum STEM Price | Source |
|---|---|---|---|---|
| Mean Variable O&M | $/MWh | $32.04 | $32.04 | Simulations |
| Mean Heat Rate | GJ/MWh | 18.735 | 18.774 | Simulations |
| Mean Fuel Cost | $/GJ | $10.68 | $21.65 | Simulations, fixed distillate price. |
| Loss Factor | | 1.0295 | 1.0295 | Western Power Networks |
| Before Risk Margin 6.20.7(b) [32] | $/MWh | $225.48 | $425.93 | Method 6.20.7(b) |
| Risk Margin | $/MWh | $55.52 | $36.07 | By difference from Energy Price Limits |
| | % | 24.6% | 8.5% | By ratio |
| Assessed Maximum Price | $/MWh | $281.00 | $462.00 | Table F- 2 |

[32] Mean values have been rounded for the purpose of this calculation.

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■ Table F- 2 Cost analysis without carbon price

| Sample | Aero Derivative – LM6000 | | Industrial Gas Turbine | |
|---|---|---|---|---|
| | Gas | Distillate | Gas | Distillate |
| Mean | $193.35 | $257.18 | $225.43 | $425.88 |
| 80% Percentile | $222.45 | $277.93 | $280.99 | $468.75 |
| 90% Percentile | $242.17 | $288.18 | $318.90 | $500.37 |
| 10% Percentile | $151.11 | $225.23 | $150.51 | $360.14 |
| Median | $190.03 | $256.51 | $215.95 | $419.46 |
| Maximum | $339.79 | $368.48 | $519.31 | $750.70 |
| Minimum | $113.85 | $179.84 | $82.74 | $295.79 |
| Standard Deviation | $34.88 | $26.10 | $65.92 | $58.17 |
| **Non-Fuel Component $/MWh** | | | | |
| Mean | | $9.66 | | $31.12 |
| 80% Percentile | | $9.84 | | $34.36 |
| 90% Percentile | | $9.56 | | $44.87 |
| **Fuel Component GJ/MWh** | | | | |
| Mean | | 10.942 | | 18.236 |
| 80% Percentile | | 11.476 | | 19.751 |
| 90% Percentile | | 11.875 | | 20.399 |
| **Equivalent Fuel Cost for % Value** | | **$/GJ** | | |
| Mean | | 22.622 | | 21.647 |
| 80% Percentile | | 23.360 | | 21.993 |
| 90% Percentile | | 23.464 | | 22.329 |