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Mr Rajat Sarawat
Executive Director
Economic Regulation Authority
Level 4, Albert Facey House
469 Wellington Street
PERTH WA 6000

Dear Rajat,

SUBMISSION UNDER CLAUSE 2.26.1

In accordance with clause 2.26.1 of the Wholesale Electricity Market Rules (Market Rules), the Independent Market Operator (IMO) is pleased to provide the Economic Regulation Authority (ERA) with its proposal for the Maximum Reserve Capacity Price (MRCP) to apply during the Capacity Year commencing 1 October 2015 (2015/16 Capacity Year).

The MRCP proposed in this submission has been developed in accordance with the methodology prescribed in the *Market Procedure: Maximum Reserve Capacity Price*.

The proposed MRCP of $157,000 is 4% lower than the 2014/15 MRCP of $163,900. Full details on the factors that have contributed to the reduction are contained within the Final Report.

We look forward to working with the ERA during its consideration of this proposal. If you have any queries please do not hesitate to contact Johan van Niekerk on 9254 4399.

Yours sincerely

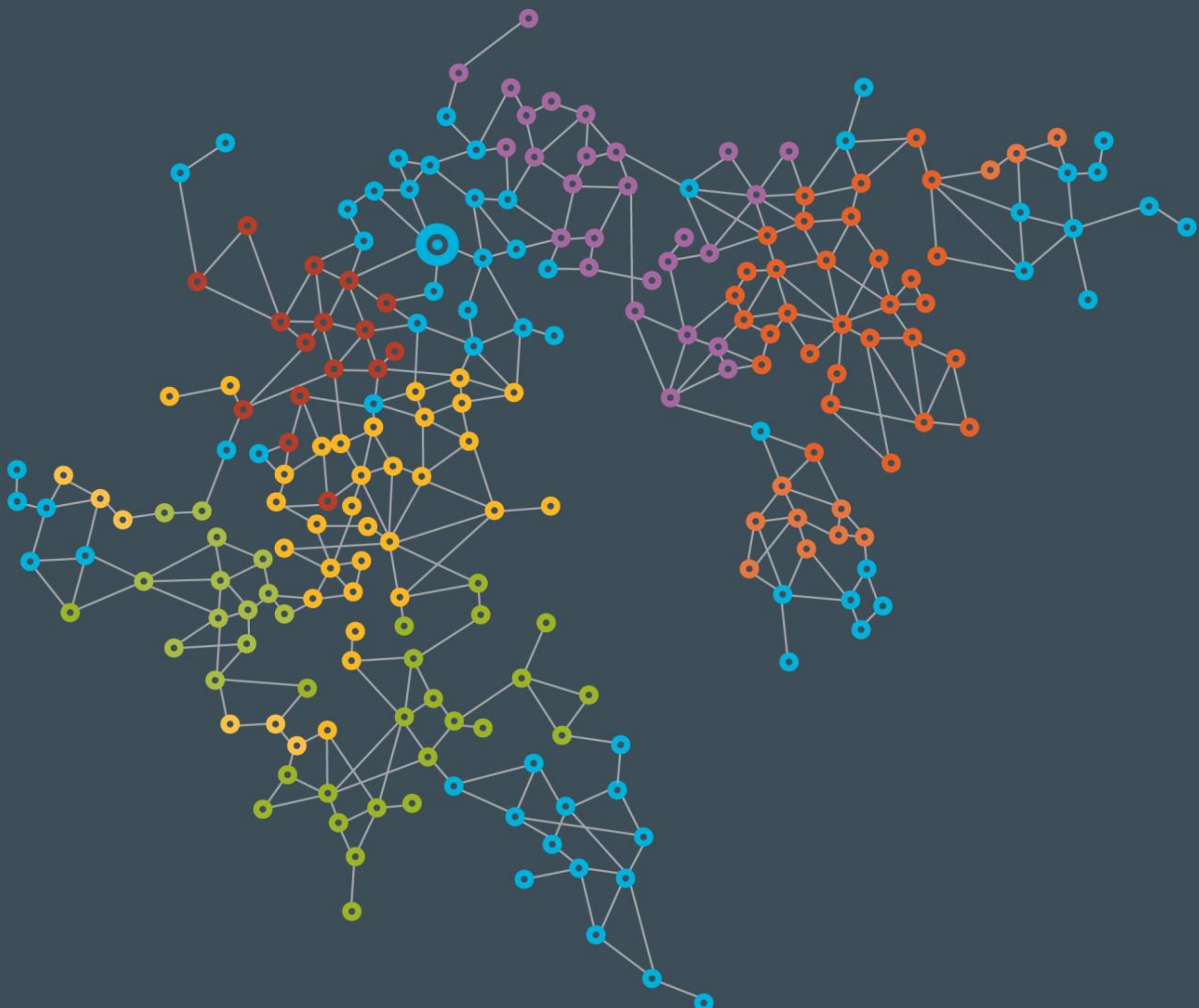
MURRAY CRIBB
ACTING CHIEF EXECUTIVE OFFICER

16 January 2013

INDEPENDENT MARKET OPERATOR

Final Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year

January 2013



DISCLAIMER

The Independent Market Operator (IMO) has prepared this report under section 4.16 of the Wholesale Electricity Market Rules (Market Rules) to describe the process it followed in arriving at a proposed revised value for the Maximum Reserve Capacity Price.

Although all due care has been taken in preparing this report, the IMO makes no guarantee that it is completely accurate and accepts no liability for any errors.

EXECUTIVE SUMMARY

Each year, the Independent Market Operator (IMO) is required to determine the Maximum Reserve Capacity Price in accordance with the *Market Procedure: Maximum Reserve Capacity Price*[1] ("Market Procedure").

The Maximum Reserve Capacity Price (MRCP) sets the maximum bid price that can be made in a Reserve Capacity Auction and is also used as the basis to determine an administered Reserve Capacity Price if no auction is required.

The MRCP aims to establish the marginal cost entry of providing additional Reserve Capacity in each Capacity Year. The MRCP is established by undertaking a technical bottom-up cost evaluation of the entry of a 160 MW Open Cycle Gas Turbine (OCGT) generation facility entering the Wholesale Electricity Market (WEM) in the relevant Capacity Year.

This Final Report details the outcome of the determination of the MRCP for the 2013 Reserve Capacity Cycle. The value used for the 2013 Reserve Capacity Cycle will be effective from 1 October 2015 through to 1 October 2016.

The methodology for determining the MRCP is specified in the Market Procedure and includes a technical costing of the following components:

- the capital cost of a 160 MW OCGT power station with inlet cooling, located within the South West interconnected system (SWIS);
- the land cost associated with developing and constructing the power station;
- the cost associated with connection of the power station to the transmission system;
- the cost associated with building liquid fuel storage and handling facilities for the power station to accommodate 24 hours of operation;
- the fixed Operational and Maintenance (O&M) costs associated with the power station and the transmission facilities listed above;
- a margin for legal, approval, financing and insurance costs and contingencies; and
- the Weighted Average Cost of Capital (WACC).

The methodology (valuing the cost of entry of a 160 MW OCGT power station) employed this year for determining the MRCP is identical to that used last year.

MRCP outcome

The 2013 Maximum Reserve Capacity Price proposed by the IMO in this Final Report is $157,000 per MW per year. This is 4.2% lower than the MRCP of $163,900 determined for the 2012 Reserve Capacity Cycle.

[1] The Market Procedure is available at http://www.imowa.com.au/market-procedures

The final MRCP has been determined using a WACC with a franking credit value, or gamma, of 0.25. The change in the gamma from 0.5 to 0.25 is facilitated by the approval and commencement of Procedure Change Proposal PC_2012_08[2].

Changes since 2014/15 MRCP

Table A shows the impact of changes in the input parameters since the 2014/15 MRCP.

Table A: Impact of changes in input parameters

	Impact ($)	Impact (%)	MRCP ($)
2014/15 MRCP			**163,900**
Escalation factors	+ 400	+ 0.2%	164,300
Power Station costs	- 4,300	- 2.6%	160,000
Margin M	+ 600	+ 0.4%	160,600
Fixed Fuel Cost	+ 2,800	+ 1.7%	163,400
Land Cost	- 100	- 0.1%	163,300
Transmission Cost	+ 600	+ 0.4%	163,900
WACC	- 7,700	- 4.7%	156,200
Fixed O&M	+ 800	+ 0.5%	157,000
Combined impact	**- 6,900**	**- 4.2%**	**157,000**

The most significant changes since the 2014/15 MRCP are explained below.

- The Power Station Cost is 3.4% lower than for 2014/15, with the reduction driven by falling steel and copper prices coupled with the appreciation of the Australian dollar versus the Euro.
- The Fixed Fuel Cost is 122% higher than last year. Sinclair Knight Merz (SKM) has reviewed this estimate for the first time, based on the same scope as previous estimates provided by GHD. SKM has developed its estimate with the benefit of recent project experience in Western Australia.
- The WACC has reduced from 6.83% to 5.95%. This has been driven by a further deterioration in bond yields in the past year and the use, for the first time, of the “Bond-Yield Approach” developed by the Economic Regulation Authority (ERA) for determining the debt risk premium.

[2] See http://www.imowa.com.au/PC_2012_08

Stakeholder workshop held on 1 November 2012

In submissions on the 2014/15 MRCP, a number of stakeholders suggested that the capital structure assumptions that underpin the WACC calculation may not be appropriate for the current composition of the WEM. In particular, these stakeholders suggested that it was likely that a generator in the WEM would raise debt finance from a bank rather than through the corporate bond market. The IMO committed to review these assumptions in 2012.

The IMO commissioned PricewaterhouseCoopers (PwC) to review recent regulatory practice with regards to the cost of debt. The report from PwC, as included in the workshop papers, advised that:

- it remains current regulatory practice to determine the risk free rate from a 20-day average of recent observed yields of Commonwealth Government bonds;
- no challenges to this method for determining the risk free rate have been brought to the ACT recently;
- no Australian regulator has applied a cost of debt estimate that is based on the cost of bank debt; and
- there has been a sustained shift in the practice of both the Australian Energy Regulator (AER) and ERA to apply a value of gamma of 0.25.

The IMO confirmed to attendees that it would progress with a Procedure Change Proposal to amend the value of gamma, and would retain the determination of the risk free rate and debt risk premium from observed yields of Commonwealth Government and corporate bonds respectively.

In addition to the review by PwC, the IMO separately consulted with banks to determine whether banks maintained a robust benchmark or index of the cost of debt that was publicly available. The banks contacted confirmed that the cost of bank debt was determined on a project-by-project basis and that no such benchmark was publicly available.

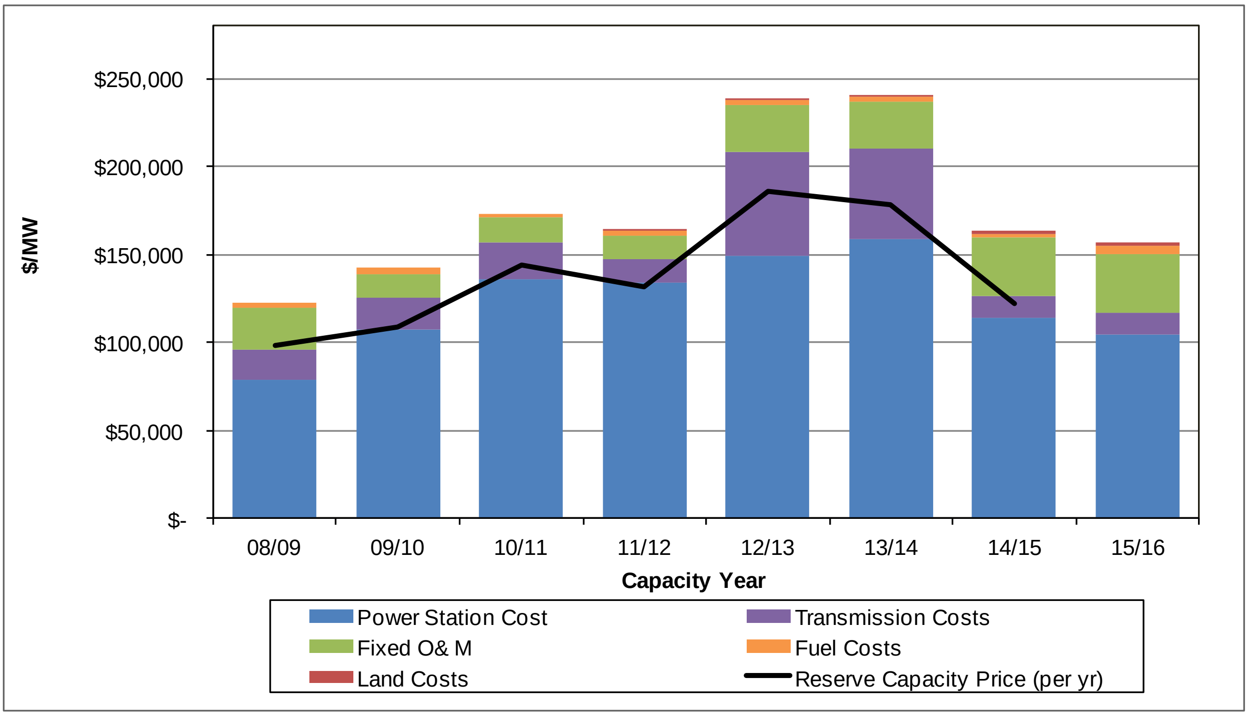
Historical variation of MRCP

Figure B indicates that the MRCP has been relatively stable aside from the MRCPs for 2012/13 and 2013/14, which are outliers. This graph shows the MRCPs for the period from 2008/09 to 2015/16, including the contribution of the various component costs. Please note the individual cost components include the impact of the WACC.

As shown in the graph, the higher MRCPs for 2012/13 and 2013/14 were largely driven by higher estimates of Transmission Costs, which are provided by Western Power. The IMO notes that the method used by Western Power changed for the 2012/13 MRCP following discussions between the IMO and Western Power. The IMO considered that estimates provided by Western Power for previous years lacked detail and transparency. However, the IMO notes that the 2012/13 estimate provided by Western Power for the shared connection cost at the cheapest location was more than 350% higher than the indicative value provided for the 2011/12 MRCP.

As part of the five-yearly review of the MRCP, assisted by the Maximum Reserve Capacity Price Working Group (MRCPWG), SKM reviewed the methodology employed by Western Power. In its analysis, SKM highlighted that the method used for the 2012/13 and 2013/14 MRCPs required a broad range of assumptions that can lead to significant inaccuracies and year-to-year volatility.

Figure B: MRCPs for 2008/09 to 2015/16 Capacity Years



An amended methodology for estimating the Transmission Costs was implemented following this review[3], based on a weighted average of actual contribution costs charged by Western Power. Western Power applied the new methodology for the first time for the 2014/15 MRCP. The outcomes of this methodology have been significantly lower than the estimates provided by Western Power for 2012/13 and 2013/14, suggesting that the higher cost estimates provided for those years were not reflective of the capital contributions actually being charged to project developers that have either secured connection or been provided with an Access Offer.

Outside of the 2012/13 and 2013/14 MRCPs, the Transmission Cost component of the MRCP has been relatively stable with estimates falling within 20% of the mean for the remaining years[4].

The IMO notes that the current methodology for estimating the Transmission Costs uses several years of data in a weighted average calculation. This method is expected to result in lower volatility than occurred under the previous methodology employed by Western Power for 2012/13 and 2013/14.

[3] See Procedure Change PC_2011_06.
[4] This analysis excludes the effect of the WACC.

The IMO also notes that the Power Station Cost increased by 101% from the 2008/09 MRCP to the 2013/14 MRCP, driven by significant increases in commodity prices and WA labour costs. The introduction of inlet cooling into the design of the theoretical power station, following the 5-yearly MRCP methodology review, has moderated this increase and was the predominant reason for the reduction in the Power Station Cost from 2013/14 to 2014/15. This change was implemented as it reflects current market practice. All OCGT generation facilities constructed in the SWIS since the commencement of the WEM have incorporated inlet cooling.

Procedure Change PC_2012_08

As noted above, Procedure Change Proposal PC_2012_08[5] to amend the Market Procedure has been approved since the publication of the Draft Report and the revised Market Procedure commenced on 15 January 2013.

This Final Report has been prepared in accordance with the revised Market Procedure. The only amendment that has affected the calculated MRCP is a change in the value of gamma from 0.5 to 0.25.

ERA Review of MRCP Methodology

The ERA is required under clause 2.26.3 to review the methodology for setting the MRCP not later than the fifth anniversary of the first Reserve Capacity Cycle and has indicated that it will perform this review in 2013. Stakeholders will have the opportunity to provide submissions as part of this review.

[5] See http://www.imowa.com.au/PC_2012_08

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1. INTRODUCTION

The Maximum Reserve Capacity Price (MRCP) sets the maximum bid that can be made in a Reserve Capacity Auction and is used as the basis to determine an administered Reserve Capacity Price if no auction is required. Each year the Independent Market Operator (IMO) is required to determine the MRCP in accordance with the *Market Procedure: Maximum Reserve Capacity Price*[6] (Market Procedure). Following the public consultation process, the IMO must consider submissions and propose a final revised MRCP value and submit that value, along with a final report (produced in accordance with clause 4.16.7 of the Market Rules) to the Economic Regulation Authority (ERA) for approval.

This Final Report presents the updated component costs as determined for the 2013 Reserve Capacity Cycle. The IMO uses publicly available information, together with advice from independent engineering and economics consultants and Western Power, to update the various input parameters that are used in calculating the MRCP.

This Final Report is produced in accordance with clause 4.16.6 of the Wholesale Electricity Market Rules (Market Rules).

1.1 Reserve Capacity Cycle timing

This Final Report has been prepared for the 2013 Reserve Capacity Cycle and the MRCP will be effective from 1 October 2015 through to 1 October 2016.

1.2 General costing methodology and structure of this Final Report

The yearly determination of the MRCP requires the IMO to develop estimates of the following constituent costs:

- the capital cost of a 160 MW Open Cycle Gas Turbine (OCGT) power station with inlet cooling, located within the South West interconnected system (SWIS);
- the land cost associated with developing and constructing the power station;
- the cost associated with connection of the power station to the transmission system;
- the cost associated with building liquid fuel storage and handling facilities for the power station;
- the fixed Operational and Maintenance (O&M) costs associated with the power station and the transmission facilities listed above;
- a margin for legal, approval, financing and insurance costs and contingencies; and
- the Weighted Average Cost of Capital (WACC).

In determining the proposed MRCP, the IMO has sought advice from various consultants and

[6] The Market Procedure is available at http://www.imowa.com.au/market-procedures

agencies. Table 1 lists these organisations and the input parameters for which they have provided advice.

Table 1: Consultants and agencies

Organisation	Cost estimate(s) provided
Sinclair Knight Merz (SKM)	Power station capital cost Margin for indirect costs and contingencies Fixed Fuel Cost O&M costs
Landgate	Land cost
Western Power	Transmission connection cost
Pricewaterhouse Coopers (PwC)	Debt Risk Premium

As shown in Table 1, SKM has been engaged to determine the Fixed Fuel Cost that was provided by GHD last year. PwC has been appointed to determine the Debt Risk Premium (DRP). The remaining annual WACC parameters have been determined by the IMO for the first time using available market data.

1.3 Public Consultation

Following publication of the Draft Report on 21 November 2012, the IMO invited public submissions until the submission deadline of 19 December 2012. The IMO received five submissions from the following parties:

- Community Electricity;
- Verve Energy;
- Perth Energy;
- Merredin Energy; and
- Alinta Energy.

A summary of the submissions received and the IMO's response to each of the issues raised is included in Section 5 of this report. The full details of the submissions are available on the IMO website.

1.4 MRCP outcome for the 2013 Reserve Capacity Cycle

In accordance with clause 4.16.7 of the Market Rules and having considered the submissions received, the IMO proposes a final revised value of the MRCP of $157,000 per MW per year for the 2013 Reserve Capacity Cycle.

This is a reduction of 4.2% from the 2012 MRCP of $163,900 per MW per year.

A detailed analysis of the changes since the 2014/15 MRCP is included in Section 4.4 of this report. This analysis is presented for both scenarios described above.

1.5 Stakeholder workshop held on 1 November 2012

In submissions on the 2014/15 MRCP, a number of stakeholders suggested that the capital structure assumptions that underpin the WACC calculation may not be appropriate for the current composition of the WEM. In particular, these stakeholders suggested that it was likely that a generator in the WEM would raise debt finance from a bank rather than through the corporate bond market. The IMO committed to review these assumptions in 2012.

The IMO commissioned PricewaterhouseCoopers (PwC) to review recent regulatory practice with regards to the cost of debt. PwC was requested to only consider Australian regulators whose decisions are reviewable by the ACT. The IMO also requested advice with regard to regulatory practice in determining:

- the risk free rate, given that Commonwealth Government bond yields have further declined to historic lows; and
- the value of imputation credits (gamma), given the observed shift in regulatory decisions by the Australian Energy Regulator (AER) and the ERA.

PwC advised that:

- it remains current regulatory practice to determine the risk free rate from a 20-day average of recent observed yields of Commonwealth Government bonds;
- no challenges to this method for determining the risk free rate have been brought to the ACT recently;
- no Australian regulator has applied a cost of debt estimate that is based on the cost of bank debt; and
- there has been a sustained shift in the practice of both the AER and ERA to apply a value of gamma of 0.25.

In addition to the review by PwC, the IMO separately consulted with banks to determine whether banks maintained a robust benchmark or index of the cost of debt that was publicly available. The banks contacted confirmed that the cost of bank debt was determined on a project-by-project basis and that no such benchmark was publicly available.

The IMO confirmed to attendees that it would progress with a Procedure Change Proposal to amend the value of gamma, and would retain the determination of the risk free rate and DRP from observed yields of Commonwealth Government and corporate bonds respectively.

1.6 Procedure Change Proposal

Procedure Change Proposal PC_2012_08[7] to amend the Market Procedure has been approved since the publication of the Draft Report and the revised Market Procedure commenced on 15 January 2013. This proposal included two changes that have the potential to impact the

[7] See http://www.imowa.com.au/PC_2012_08

calculation of the MRCP:

- The franking credit value, gamma, would be amended from 0.5 to 0.25 to align with recent Australian regulatory practice. Following a decision by the Australian Competition Tribunal in May 2011[8], both the AER and ERA have regularly applied a value of 0.25 in regulatory decisions. This proposed change will have a material impact on the MRCP as noted in Section 1.4 above.
- With the commencement of the Balancing Market in 2012, the power station would be required to comply with the Balancing Facility Requirements. However, the IMO notes that the Balancing Facility Requirements currently consist of communication systems that have a negligible impact on the capital cost for the power station.

This Final Report has been prepared in accordance with the revised Market Procedure. The only amendment that has affected the calculated MRCP is the change in the value of gamma from 0.5 to 0.25.

1.7 ERA Review of MRCP Methodology

The ERA is required under clause 2.26.3 to review the methodology for setting the MRCP not later than the fifth anniversary of the first Reserve Capacity Cycle and has indicated that it will perform this review in 2013. Stakeholders will have the opportunity to provide submissions as part of this review.

1.8 Supporting Documents

The following related documents are available on the IMO website (http://www.imowa.com.au/mrcp):

- *Draft Report: Maximum Reserve Capacity Price Review for the 2015/16 Capacity Year*;
- MRCP Calculation Spreadsheet, Final Report version;
- WACC parameter calculation spreadsheet (risk free rate and inflation), Final Report version;
- PwC letter, dated 18 December 2012, *Update of debt risk premium using the ERA's debt yield methodology*;
- SKM letter, dated 2 January 2013, *2015/16 MRCP Construction Insurance Cost*;
- MRCP Calculation Spreadsheet, Draft Report versions:
  - Version 1 is prepared in accordance with the current Market Procedure, using a gamma of 0.5;
  - Version 2 is prepared with a gamma of 0.25 as would be adopted if PC_2012_08 is accepted;

[8] Application by Energex Limited (Gamma) (No 5) [2011] A CompT 9 (12 May 2011)

- SKM report, dated 30 October 2012, *Review of the Maximum Reserve Capacity Price 2013* (Final Report version)[9];
- PwC letter, dated 11 October 2012, *Debt risk premium using the ERA's debt yield methodology*;
- WACC parameter calculation spreadsheet (risk free rate and inflation), Draft Report version;
- Letter from Landgate, dated 11 September 2012, *Land Values for Reserve Capacity Price*;
- Western Power report, dated 8 October 2012, *Total Transmission Cost Estimate for the Maximum Reserve Capacity Price for 2015/16*[10];
- PwC letter, dated 15 October 2012, *Review of debt and equity related issues within the WACC used in the Maximum Reserve Capacity price*; and
- Minutes of the WACC Workshop held 1 November 2012.

[9] Please note that updates have been made to pages 7 and 36 of SKM's Report since publication of the Draft Report. SKM has corrected errors in the $/kW and cost escalation calculations. Please note that the IMO's calculations in the Draft Report were correct as they had not used these figures..

[10] Please note that an update to this report since publication of the Draft Report has been made to correct a discrepancy in the easement value in section 2.3.3 of Western Power's Report. The IMO's Draft Report was based on the correct value in section 2.3.4.

2. ESCALATION OF COSTS

The Market Procedure describes a number of escalation factors that are applied to various costs within the MRCP. These escalation factors are used to estimate the changes in costs from the time at which price estimates are derived to the time at which, for the purpose of the MRCP, the capital is assumed to be outlaid.

The calculation for the 2013 MRCP is based on a theoretical power station that would commence operation on 1 October 2015. In line with the Market Procedure, capital costs are escalated to 1 April 2015 and O&M costs have been escalated to 1 October 2015. The various input costs have been provided to the IMO at different dates, which are provided in Chapter 3 of this report.

The IMO proposes to use the escalation factors summarised in Table 2, which are unchanged from the values in the Draft Report.

Table 2: Escalation Factors

Escalation Factor	Financial Year				
	2012/13	2013/14	2014/15	2015/16	2016/17
CPI	3.25%	2.50%	2.50%	2.50%	
Power Station Capital Cost	1.62%	4.39%	3.33%	2.85%	2.85%
Connection Asset O&M Cost	4.32%				
Power Station O&M Cost	3.79%	3.60%	3.61%	3.62%	
Transmission Connection Cost	-2.91%				

Where possible cost escalation factors are based on forecast price movements. Labour costs are projected based on long-run historical cost escalation, observed in labour price indices published by the Australian Bureau of Statistics.

The following escalation factors have been determined for use in the MRCP:

- The CPI (Consumer Price Index) escalation rates are determined from the forecasts of the Reserve Bank of Australia (RBA)[11] as described in the Market Procedure. The mid-point of the RBA's target range of inflation is used beyond the period of the forecasts, resulting in a constant escalation rate from the 2015/16 financial year onwards.
- The power station capital cost escalation factors have been determined by SKM and are published in its report. SKM has calculated these escalation factors by weighting historical and forecast movements of specific input cost drivers such as steel, copper and labour costs. The weighting of each input cost driver relates to its contribution to the total capital cost of the power station.
- Escalation factors for connection asset O&M costs have also been calculated by SKM.

[11] Published in the Statement on Monetary Policy, November 2012.

SKM has noted in previous years that fixed O&M costs for these assets are dominated by labour costs, so the labour cost escalation rates are used to escalate these O&M costs. The labour cost escalation factors are determined from the 10-year average movement in Labour Price Indices, so a single escalation rate has been applied in the MRCP calculation.

- Escalation factors for power station O&M costs have also been determined by SKM. These escalation factors are derived by weighting labour escalation rates and CPI.
- The transmission connection cost escalation factor is determined from the average annual change in Western Power cost estimates for a fixed transmission connection scope, as described in Section 2.4 of the Market Procedure. This has been provided in Western Power's report.

Further detail on the development of these escalation factors can be found in the applicable supporting documents on the IMO website at http://www.imowa.com.au/mrcp.

3. INPUT PARAMETERS TO THE MAXIMUM RESERVE CAPACITY PRICE CALCULATION

3.1 Power Station Capital Costs (PC)

As with the 2012 MRCP determination, the IMO commissioned SKM to provide generation plant capital costs for a 160 MW OCGT power station located within the SWIS. This is the sixth year in which SKM has provided this estimate to the IMO. The scope provided to SKM was identical to last year in all respects, except that the facility now needs to meet the Balancing Facility Requirements as implemented from 1 July 2012.

SKM developed the capital cost estimate for a generic 160 MW OCGT power station (including procurement, installation and commissioning) using Thermoflow GT Pro®/PEACE® and benchmarked the costs of equipment and labour against actual projects.

For the purposes of the 2013 MRCP:

PC = A$829,446.75 per MW

This price represents a decrease of 3.4% from the corresponding value for the 2012 MRCP and is unchanged from the value in the Draft Report. The key drivers of this change have been weakening steel and copper prices as well as a strengthening of the Australian dollar versus the Euro. SKM notes in its report that the *"weakening Euro or conversely the relative strength of the Australian dollar results in a reference price decrease of approximately 10% for the SGT5-200E gas turbine plant".*

3.2 Legal, financing, insurance, approvals, other costs and contingencies (M)

The parameter M is defined as a margin to cover legal, financing, insurance, approvals, other costs and contingencies. SKM was commissioned to provide an estimate of these costs for 2013. This is the fifth year in which SKM has provided this parameter for the IMO.

The margin M is estimated from the costs associated with recent comparable developments, excluding any abnormal costs that may be particular to individual projects. Costs are scaled for a 160 MW power station where relevant. M is added as a fixed percentage of the capital cost of developing the power station.

For the purposes of the 2013 MRCP:

M = 18.87%

This value has risen from the corresponding value of 18.2% for the 2012 MRCP. The margin M is added as a fixed percentage of the capital cost of developing the power station. However, SKM has advised that many costs included under M, such as engineering design, project management and legal costs are fixed in nature. As the Power Station Capital Costs (PC) have reduced, these fixed costs represent a higher percentage of PC.

It has also increased from the value of 18.77% in the Draft Report in response to a submission by Merredin Energy. Merredin Energy pointed out that SKM had maintained the allowance for construction insurance at 0.4% of the EPC cost of the plant, consistent with the 2012 MRCP, but that the IMO had separately received advice from an insurance broker that insurance premiums had risen by approximately 22.5% since last year (see Section 3.8.4 of this report). The IMO consulted with SKM, which has increased the allowance for construction insurance from 0.4% to 0.5%, as detailed in the letter from SKM dated 2 January 2013.

3.3 Transmission Connection Costs (TC)

For the 2013 MRCP, Western Power has calculated the transmission connection cost estimate as part of its obligations under the Market Procedure.

The Transmission Connection Cost estimate provided for this MRCP determination is based on actual connection costs and Access Offers that have been determined by Western Power. As the connection costs for individual projects are confidential to Western Power and the project developer, Western Power has provided an audit report verifying the connection cost data used in the calculation.

The Transmission Connection Cost is calculated using actual connection costs for projects within a 5-year window, and weights each connection cost according to the year that the facility commenced, or is expected to commence, operation. The Transmission Connection Cost is based on a 5 year weighted average calculation, not directly from the shallow connection cost estimate determined by Western Power.

This methodology for estimating the Transmission Connection Cost was implemented following the five-yearly review of the MRCP, assisted by the Maximum Reserve Capacity Price Working Group (MRCPWG), and was applied by Western Power for the first time for the 2014/15 MRCP. In analysis for the MRCPWG, SKM highlighted that the method employed by Western Power for the 2012/13 and 2013/14 MRCPs required a broad range of assumptions that can lead to significant inaccuracies and year-to-year volatility.

The outcomes of this methodology are significantly lower than the estimates provided by Western Power for 2012/13 and 2013/14, suggesting that the higher cost estimates for those years were not reflective of the capital contributions actually being charged to project developers that have either secured connection or been provided with an Access Offer.

For the purposes of the 2013 MRCP:

TC = A$115,124 per MW

This value is approximately 4.8% higher than the corresponding value in 2012 and is unchanged from the value in the Draft Report. The IMO notes that, outside of the 2012/13 and 2013/14 MRCPs, the Transmission Connection Cost component of the MRCP has been relatively stable with estimates falling within 20% of the mean for the remaining years[12].

For further information regarding the costing provided by Western Power, please refer to the Western Power report[13] published on the IMO website (http://www.imowa.com.au/mrcp).

3.3.1 Easement Costs

To assist Western Power in its determination of the transmission connection cost estimate, the IMO provides an estimate of easement costs for the direct connection scope described in step 2.4.2 of the Market Procedure.

The IMO has estimated the easement cost on the same basis as last year.

- The easement is assumed to be 2km long and 60m wide (an area of 12 hectares).
- The IMO has assumed that a project developer may not be required to purchase the full portion of land and could instead secure easement rights for some or all of the easement. As such, the IMO has estimated the easement costs to be 50% of the purchase value of the land, consistent with the 2012 MRCP.
- The purchase price per hectare has been estimated by dividing the average cost of the land parcels (as valued by Landgate) by three hectares. Note that this cost estimate is as at 30 June 2012.

To meet the requirements for the transmission connection cost estimate (Section 2.4 of the Market Procedure), the IMO has escalated the resulting value forward to 30 June 2013 using the CPI escalation factor for the 2012/13 financial year of 3.0%. Further escalation of this cost to 1 April 2015 occurs within the transmission connection cost estimate methodology where required.

The IMO has estimated that the easement cost as at 30 June 2013 is A$5.147M, down 3.6% from the 2012 value of A$5.339, predominantly due to a small reduction in the cost of land at Pinjar and Kwinana. This value is unchanged since the Draft Report.

3.4 Fixed Fuel Costs (FFC)

Fixed Fuel Costs for the determination of the 2013 MRCP have been estimated by SKM. The Fixed Fuel Costs were previously calculated by GHD, which provided these estimates for the last five years.

SKM has provided its cost estimate as at 30 June 2012, which has been escalated to 1 April 2015, using the CPI escalation rates from Table 1.

For the purposes of the 2013 MRCP:

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[12] This analysis excludes the effect of the WACC.
[13] See Western Power report *Total Transmission Cost Estimate for the Maximum Reserve Capacity Price for 2015/16*.

FFC = A$7.069 M

This price represents an increase of 122% from the corresponding value for the 2012 MRCP. SKM has estimated the Fixed Fuel Costs based on the same scope as the previous estimates provided by GHD. SKM has developed its estimate with the benefit of recent project experience in Western Australia.

This value is unchanged since the Draft Report.

3.5 Land Costs (LC)

The IMO commissioned Landgate to update the land cost estimates to be used in the MRCP determination. This is the fifth year in which Landgate has provided these estimates to the IMO.

These estimated land valuations are based on guidelines outlined in the Market Procedure. Valuations were conducted for seven locations in regions where development of a power station within the SWIS would be reasonably likely. The regions included were:

- Collie Region;
- Kemerton Industrial Park Region;
- Pinjar Region;
- Kwinana Region;
- North Country Region (both Geraldton and Eneabba); and
- Kalgoorlie Region.

Land sizes and costs were determined in accordance with the Market Procedure. Three hectare sites were used for all locations except Kemerton, for which the smallest available lot is five hectares. This approach is identical to that used in the 2012 MRCP.

Landgate has provided its estimate of the cost of each land parcel as at 30 June 2012, excluding stamp duty. The IMO has added the applicable stamp duty to each land parcel cost, determined by the online calculator provided by the Office of State Revenue[14]. In accordance with the Market Procedure, the IMO has calculated the mean of the seven valuations. This average land cost has been escalated to 1 April 2015, using the CPI escalation rates from Table 1.

For the purposes of the 2013 MRCP:

LC = A$2.694 M

This price represents a decline of 3.9% from the corresponding value for the 2012 MRCP. This reduction in a relatively small component of the MRCP is predominantly due to a reduction in

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[14] http://rol.osr.wa.gov.au/taxcal/

the estimated land costs at Pinjar and Kwinana. The estimated cost per hectare at all other locations has remained unchanged.

This value is unchanged since the Draft Report.

3.6 Weighted Average Cost of Capital (WACC)

For the 2013 MRCP determination the IMO commissioned PwC to calculate the DRP and has calculated the remaining WACC components itself from publicly available information.

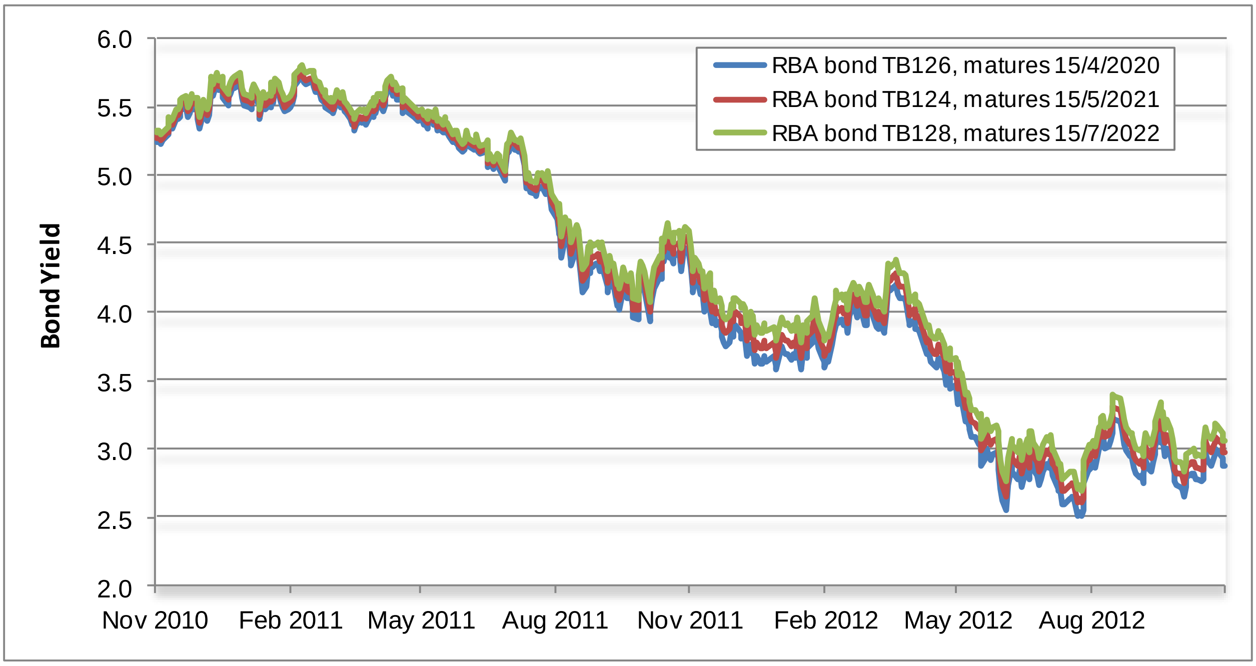
The calculations of the risk free rate and inflation are provided in a spreadsheet that is published on the IMO website at http://www.imowa.com.au/mrcp. The corporate tax rate is determined to be 30%, consistent with last year.

The WACC is determined according to the Capital Asset Pricing Model (CAPM), with bond yields considered in both the costs of equity and debt. The nominal risk free rate is determined from observed yields of Commonwealth Government bonds, while the DRP is derived from observed yields of corporate bonds.

The IMO notes that the WACC used for the determination of the 2013 MRCP reflects continuing turbulence in global financial markets, largely as a result of continuing concerns over sovereign debt levels in Europe and the slow rate of economic recovery in the US.

As market volatility has remained, investors continue to prefer lower risk investments such as government and high quality corporate bonds. Yields on RBA bonds have continued to decline since the determination of the 2012 MRCP. This is illustrated in Figure 1, which shows indicative daily yields of Commonwealth Government securities with maturity dates approximately ten years from now.

Figure 1: Stock market results and bond yields, Nov 2010 to Dec 2012[15]



A detailed calculation of the WACC is provided in Appendix A.

For the purposes of the 2013 MRCP:

WACC = 5.95%

This WACC value is significantly lower than the WACC of 6.83% determined for the 2012 MRCP. This reduction is driven by lower values for two input parameters.

- The nominal risk free rate has reduced from 3.92% to 3.14%. This parameter has been calculated from Commonwealth Government security yields using the same method as last year.
- The DRP has reduced from 4.13% to 2.71%. For 2013 the DRP has been calculated using the ERA's "Bond-Yield Approach". For the 2012 MRCP this parameter was calculated from Bloomberg fair value data. This methodology change is explained in Section 3.6.1.

These reductions have been partially offset by a reduction in the value of gamma from 0.5 to 0.25. This reduction is facilitated by the approval and commencement of Procedure Change Proposal PC_2012_08.

The WACC is slightly lower than the value proposed in the Draft Report with a gamma value of 0.25 (6.03%) due to the reduction in the DRP.

[15] Bond yield data sourced from RBA Statistical Table F16, available from http://www.rba.gov.au/statistics/tables/

3.6.1 Debt Risk Premium (DRP)

The Market Procedure requires that "*The IMO must determine the methodology to estimate the DRP, which in the opinion of the IMO is consistent with current Australian accepted regulatory practice.*"

For the 2014/15 MRCP the DRP was determined from the 7-year Bloomberg BBB fair value curve, extrapolated to 10 years using the difference between the AAA 7-year and 10-year fair value curves.

At that time, the IMO noted that the ERA had developed the "Bond-Yield Approach" for determination of the DRP, and had applied this in its *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution System*. However, the IMO also noted that this methodology had been appealed to the Australian Competition Tribunal (ACT) and that it could not be considered "*accepted regulatory practice*" until such time as it was upheld by the ACT.

In June 2012 the ACT broadly upheld the "Bond-Yield Approach" methodology. Consequently, the IMO considers that the ERA's 'Bond-Yield Approach' now represents current accepted regulatory practice in Australia.

Further, the AER recently noted in its *Final Decision, Roma to Brisbane Pipeline 2012-13 to 2016-17* that it considered that the Bloomberg methodology overstated the cost of debt, that the "Bond-Yield Approach" had been upheld by the ACT, and that it would be initiating its own review of methodologies for determining the DRP.

PwC has provided three distinct estimates in its note to the IMO based on different subsets of bonds. In the Draft Report, the IMO applied the value that represents a strict application of the ERA's approach in the WA Gas Networks final revised decision, utilising bonds with credit ratings of BBB and BBB+, with a term to maturity of at least two years.

However, in its submission, Alinta Energy questioned the appropriateness of including bonds with a credit rating of BBB+ in the determination of the DRP.

Further, the IMO notes that step 2.9.7(h) of the Market Procedure requires that the DRP be determined from "*the observed annualised yields of Australian corporate bonds which have a BBB (or equivalent) credit rating*".

Given this, the IMO considers it appropriate that the DRP for the MRCP be calculated from BBB rated bonds only and has applied this calculation in this Final Report. The IMO notes that BBB is the lowest credit rating that is considered "investment grade".

3.7 Capital Costs (CAPCOST)

The term CAPCOST refers to the total capital cost expressed in millions of Australian Dollars for the 160 MW OCGT power station. This is calculated by using the following formula:

$$CAPCOST = ((PC \times (1+M) + TC) \times CC + FFC + LC) \times (1+WACC)^{1/2}$$

For the purposes of the 2013 MRCP:

CAPCOST = A$190.939 M

3.8 Fixed Operation & Maintenance Costs (ANNUALISED_FIXED_O&M)

3.8.1 Generation

For the 2013 determination, SKM has determined the fixed O&M costs for the generator assets using the same methodology as last year. This is the seventh MRCP for which SKM has provided the estimate of these costs.

An annuity is calculated taking the first 15 years of O&M costs provided by SKM. The SKM report[16] details the total fixed O&M costs of the OCGT to year 15 as A$31.390 M in June 2012 terms. This cost is annualised and then escalated forward by 3-1/4 years, to 1 October 2015 (the point at which these costs are assumed to commence), using the power station O&M escalation factors.

For the purposes of the 2013 MRCP:

Generation Fixed O&M Costs = A$14,750.56 per MW per year

This cost represents an increase of 3.4% from the corresponding value for the 2012 MRCP and is unchanged from the value in the Draft Report.

3.8.2 Transmission

For the 2013 determination, SKM provided the fixed O&M costs of the switchyard and transmission line assets using the same methodology as last year. This is the seventh MRCP for which SKM has provided the estimate of these costs.

An annuity is calculated taking the first 15 years of O&M costs provided by SKM. The SKM report[17] details the total fixed O&M costs for the switchyard and transmission line assets. This cost is annualised and then escalated forward by 3-1/4 years, to 1 October 2015 (the point at which these costs are assumed to commence), using the connection asset O&M escalation factor.

For the purposes of the 2013 MRCP:

Transmission Fixed O&M Costs = A$425.15 per MW per year

This cost represents an increase of 1.6% from the corresponding value for the 2012 MRCP and is unchanged from the value in the Draft Report.

3.8.3 Network access charges

[16] See Table 3-2 of the SKM report *Review of the Maximum Reserve Capacity Price 2013*.
[17] See Tables 4-1 and 4-2 of the SKM report *Review of the Maximum Reserve Capacity Price 2013*.

Western Power's Price List provides the various charges for network access and related services that apply for generation facilities. It is assumed that the power station is connected to the transmission system, so reference Tariff TRT2 is used for the purpose of the MRCP.

The IMO notes that the ERA has approved Western Power's 2012/13 Price List[18] since the publication of the Draft Report. The tariffs used for the MRCP are unchanged from the price list used in the Draft MRCP Report.

As the use of system charge varies by location, the IMO has considered the list of locations nominated in step 2.7.1 of the Market Procedure, and has used the unit price for the most expensive of these locations. In the proposed 2012/13 Price List, Bluewaters has the highest price among power stations located in the regions listed in the Market Procedure.

For the purpose of the MRCP, the costs are assumed as at 1 July 2012 and have been escalated forward to 1 October 2015. The CPI escalation factor has been used as required by step 2.5.6(c) of the Market Procedure.

For the purposes of the 2013 MRCP:

Fixed Network Access Costs = A$13,687.07 per MW per year

This cost represents a decrease of 4.6% from the corresponding value for the 2012 MRCP due to the reductions in the Western Power tariffs, and is unchanged from the value in the Draft Report.

3.8.4 Insurance costs

The Market Procedure requires that the Fixed O&M component of the MRCP include annual insurance costs in respect of power station asset replacement, business interruption and public and products liability insurance as required under network access arrangements with Western Power. This is the second year that these costs have been included in the MRCP.

For the 2012 MRCP, the IMO estimated the relevant insurance premiums through consultation with two well-known insurance brokers and consideration of insurance renewal documentation provided by two Market Participants. The insurance brokers requested that they not be named. For the 2013 MRCP the IMO sought updated advice from three insurance brokers, including the same brokers that had previously provided quotations.

At the time of preparing this report advice has been received from one broker that premiums in respect of asset replacement and business interruption insurance had increased by a median of approximately 22.5%, driven by recent adverse domestic claims experience in the area of electricity generation and an increase in re-insurance costs worldwide. Given that the IMO had calculated the premium in 2011 as 0.23% of the limit of liability, this would increase the premium

[18] Available at http://www.westernpower.com.au/aboutus/accessArrangement/accessArrangement.html

to 0.28%. This broker also suggested that public and products liability insurance premiums were at similar levels to last year.

Another broker contacted by the IMO has suggested a premium for asset replacement and business interruption insurance of 0.30% of the limit of liability.

Based on previous and updated advice, the insurance premiums have been estimated as follows:

- Asset replacement and business interruption insurance is estimated as A$690,679 per year as at 1 April 2015, calculated as 0.29% of the limit of liability at that date. The limit of liability has been determined as the sum of the capital construction cost, value of fuel and the potential refund liability during the period of re-construction.

  For the purpose of asset replacement insurance, the capital construction cost and value of fuel hve been calculated as

  $$PC \times (1 + M) \times CAP + FFC$$

  where

  PC is the Power Station Capital Cost (see Section 3.1 of this report);

  M is margin M (see Section 3.2 of this report);

  CAP is the expected Capacity Credit allocation (see Section 4.3 of this report); and

  FFC is the Fixed Fuel Cost (see Section 3.4 of this report).

  For business interruption insurance, the IMO has included the potential refund liability for the facility for two years. While a construction period of one year is assumed in the application of the WACC in the MRCP calculation, a period of time would be required prior to the commencement of any reconstruction works following a loss event (for example, for procurement of services, building approvals and any demolition or clearing works). The weighting of capacity refunds to peak demand periods means that a Market Participant may be required to refund two years worth of capacity payments in a period of less than 15 months.

  Since the Draft Report, the IMO has increased the limit of liability to include the cost of fuel and has included an allowance of $20,000 to meet the cost of an annual insurance survey. These were recommended by Merredin Energy in its submission. The IMO consulted with two well-known insurance brokers on these issues. They confirmed that it is common practice for power station operators to insure liquid fuel stock at a predefined level. The same brokers confirmed that it was common industry practice for an annual site survey to be performed.

- Public and products liability insurance is estimated as A$120,000 per year as at 30 June 2012, based on a limit of $50M for any one occurrence.

Based on the information considered by the IMO, the premium rates are consistent with the following assumptions:

  - A newly constructed generation facility with on-site diesel storage;

- Location in a rural region of the SWIS, outside of any cyclone risk;
- Inclusion of coverage for machinery breakdown; and
- Deductibles of $500,000 for property damage, $100,000 for liability and 60 days for business interruption insurance.

The premiums above have been estimated to include the 2% terrorism levy and 10% stamp duty.

The insurance costs have been escalated forward to 1 October 2015 (the point at which these costs are assumed to commence), using the CPI escalation factor.

For the purposes of the 2013 MRCP:

Insurance Costs = A$5,385.90 per MW per year

This value is 23.4% higher than the corresponding value in 2012. It should be highlighted that insurance costs related to the development phase of the power station are included within margin M.

This value is 4.5% higher than the corresponding value in the Draft Report due to the increased limit of liability to cover insurance of fuel stocks as well as the inclusion of an allowance of $20,000 to meet the cost of an annual insurance survey.

3.8.5 Total Fixed Operation & Maintenance Costs

For the purposes of the 2013 MRCP:

ANNUALISED_FIXED_O&M = A$34,239 per MW per year

Total fixed operation and maintenance costs have increased by 2.5% compared to last year.

4. MAXIMUM RESERVE CAPACITY PRICE CALCULATION

4.1 Annualised Capital Costs (ANNUALISED_CAPCOST)

The annualised capital cost is determined using:

- the capital cost of A$190.939 M, as determined in Section 3.7;
- the WACC of 5.95%, as determined in Section 3.6; and
- a term of 15 years, as required by the Market Procedure.

For the purposes of the 2013 MRCP:

ANNUALISED_CAPCOST = A$19.600 M per year

4.2 Annualised Fixed Operation & Maintenance Costs (ANNUALISED_FIXED_O&M)

The total annualised fixed O&M costs are outlined in Section 3.8.5. For the purposes of the 2013 MRCP:

ANNUALISED_FIXED_O&M = A$34,239 per MW per year

4.3 Expected Capacity Credit Allocation (CC)

SKM has provided its estimate of the output of the reference facility at 41°C, which represents the expected Capacity Credit allocation for the facility. For the purposes of the 2013 MRCP:

CAP = 159.6 MW

4.4 Calculation

The Maximum Reserve Capacity Price is calculated using the following equation as required by the Market Procedure:

MRCP = (ANNUALISED_FIXED_O&M + ANNUALISED_CAP_COST / CC)

Using the values determined by the IMO and presented in previous sections, the MRCP for the 2013 Reserve Capacity Cycle is determined to be A$156,907.02 which is rounded to:

MRCP = A$157,000 per MW per year

A MRCP of A$157,000 per MW per year is proposed by the IMO. This represents a 4.2% decrease from the 2012 MRCP of $163,900.

The impact of changes in the input parameters since the 2014/15 MRCP is shown in Table 3 below.

Table 3: Impact of year-on-year changes in input parameters

	Impact ($)	Impact (%)	MRCP ($)
2014/15 MRCP			**163,900**
Escalation factors	+ 400	+ 0.2%	164,300
Power Station costs	- 4,300	- 2.6%	160,000
Margin M	+ 600	+ 0.4%	160,600
Fixed Fuel Cost	+ 2,800	+ 1.7%	163,400
Land Cost	- 100	- 0.1%	163,300
Transmission Cost	+ 600	+ 0.4%	163,900
WACC	- 7,700	- 4.7%	156,200
Fixed O&M	+ 800	+ 0.5%	157,000
Combined impact	**- 6,900**	**- 4.2%**	**157,000**

5. STAKEHOLDER INPUT

5.1 Public Submissions

The IMO published the draft report and supporting documents for the 2013 MRCP on its website and initiated a consultation process on 21 November 2012. The IMO directly advised Rule Participants and other industry stakeholders on this date and published announcements in the West Australian and the Australian Financial Review on 22 November 2012. The submission deadline was 19 December 2012.

During the public consultation period the IMO received responses from:

- Community Electricity;
- Verve Energy;
- Perth Energy;
- Merredin Energy; and
- Alinta Energy.

A copy of each submission can be found at http://www.imowa.com.au/mrcp. A summary of issues raised in submissions and IMO responses is given in the following pages.

Perth Energy and Merredin Energy raised a number of issues that are outside the scope of this annual review of the MRCP, including:

- A suggestion that the MRCP is being used to address the current excess of capacity;
- The formula for calculating the Reserve Capacity Price (RCP), including the potential removal of the 15% discount that currently applies;
- Performance requirements for DSM;
- The assignment of Capacity Credits to Facilities with high outage rates;
- The accuracy of demand forecasts; and
- Incentives for dual-fuel Facilities.

As these issues are outside the scope of this review, they are not included in the table below. However, in response to these issues the IMO notes that:

- The MRCP is determined in accordance with the Market Procedure, without regard for the capacity supply-demand position in the WEM.
- The Reserve Capacity Mechanism Working Group (RCMWG) is considering revisions to the RCP formula that would make it more responsive to the supply-demand position and address existing distortions that discourage bilateral contracting. The current proposal would remove the current 15% discount and allow the administered RCP to go above the MRCP as the supply-demand balance tightens. More information on the proceedings of the RCMWG is available at http://www.imowa.com.au/rcmwg.

- The RCMWG has reached agreement on a set of proposals to harmonise the treatment of demand-side and supply-side capacity resources by significantly increasing the minimum availability requirements for Demand Side Programmes.
- The ERA highlighted the issue of Facilities with high outage rates in its *Discussion Paper: 2012 Wholesale Electricity Market Report to the Minister for Energy*[19]. The IMO will be reviewing clauses 4.11.1(h) and 4.27 of the Market Rules in early 2013 and will consider the views from submissions to the ERA's Discussion Paper.
- The IMO recently completed the five-yearly review of the SWIS forecasting processes, including independent analysis and recommendations by ACIL Tasman. The IMO will progress the recommendations from this review during 2013.
- The IMO had previously recommended a design concept to the Office of Energy in early 2011 for an incentive mechanism for dual-fuelled facilities. In addition, the *Energy2031 Strategic Energy Initiative Directions Paper*[20] proposed the development of incentives for investment in dual-fuel electricity generation facilities. However, the Market Advisory Committee was advised in August 2012 that "*the Public Utilities Office (PUO) had considered the dual fuel issue further and concluded that the market had moved on in various ways since the initial recommendations relating to dual fuel were made*"[21]. The IMO also notes that incentives for dual-fuel facilities are not considered in the *Strategic Energy Initiative Energy2031 Final Report*[22].

[19] Available at http://www.erawa.com.au/markets/electricity-markets/annual-wholesale-electricity-market-report-to-the-minister-for-energy/
[20] Available at http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/WAs_Energy_Future/Strategic+Energy+Initiative+Directions+Paper_web.pdf
[21] Extract from meeting minutes, available at http://www.imowa.com.au/mac_52
[22] Available at http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/WAs_Energy_Future/Strategic_Energy_Initiative_Energy2031_Final_Paper.pdf

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
1	Community Electricity	General	We expressly support the manner in which the Market Procedure: Maximum Reserve Capacity Price has been applied.	The IMO notes Community Electricity's support.
2	Community Electricity	Historical variation of the MRCP	We note and support the IMO's commentary to the effect that the Maximum Reserve Capacity Price has been relatively stable since market commencement with the exception of two consecutive extremes caused by a sub-optimal procedure for determining transmission connection costs, which has now been superseded. We consider that the two extreme valuations have created the erroneous perception of a substantial fall in the Maximum Reserve Capacity Price in recent years, while it was actually the former substantial increase that was erroneous. On this basis, we support the pricing outcome of the present review as being appropriately contiguous with historical valuations, especially having regard to matters such as bond yields and the value of the Australian dollar.	The IMO notes Community Electricity's support.
3	Perth Energy	Historical variation of the MRCP	From our own experience of providing capacity in the WEM, PE believes that investment capital will not be attracted to providing peaking plant (within a 2-3 year capacity cycle) unless the price for capacity is relatively predictable. It is unlikely that investors will commit to 20 year investment decisions based on the low WACC and inherent uncertainty and lack of commercial rationale in MRCP/RCP determination. Our view is the current situation will likely jeopardise the provision of new generation capacity in the future. As a retailer this is of significant worry to us as it could reconcentrate the supply side to the detriment of consumers.	The IMO considers that the MRCP has been relatively stable aside from the MRCPs for 2012/13 and 2013/14, which are outliers. As described in the Executive Summary of this report the higher MRCPs for 2012/13 and 2013/14 were largely driven by higher estimates of Transmission Costs from Western Power that were not reflective of the capital contributions actually being charged to generation project developers.
4	Merredin Energy	Margin M	SKM's estimate of construction insurance costs has not been updated and remains inadequate at 0.4%. The IMO, in its report on annual insurance costs, noted insurance premiums had increased 22.5%. It is disappointing that had not	As stated in its report, SKM had used an unchanged rate for construction insurance from that used in the 2012 MRCP. The IMO has discussed this issue with SKM and

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
			identified by SKM as an issue prior to its report having been released. It may be sensible for construction insurance costs to be separately estimated as a MRCP parameter rather than being assessed by SKM and rolled into the M factor. The construction insurance costs need to be amended to reflect current market rates. Furthermore, the extent of cover needs to be analysed and disclosed. Importantly, because of the capacity credit refund regime, construction insurance needs to cover consequential losses of 24 months for capacity credits refund liabilities (consistent with the approach applied to operational business interruption insurance) to cover loss events during construction that lead to subsequent capacity credit refunds. Merredin Energy had to take out the following insurance cover during construction: Construction Material Damage Construction Advanced Business Interruption Construction Liability (General and Products Liability) Construction Marine Cargo & Marine Advanced Business Interruption Directors and Officers Liability Cover Merredin Energy's insurance premiums totalled $600,000 in our first year of construction. This represented around 0.8% of the EPC contract sum, prior to the 22.5% increase in premiums recently experienced. Based on our calculations, the insurance margin should be at least 1.0%.	considers it appropriate that the increase in insurance costs also be reflected in the construction insurance costs in margin M. This is reflected in the letter from SKM dated 2 January 2013, indicating that is has increased the allowance from 0.4% to 0.5%. The IMO considers it likely that the risk of refund liabilities due to delays in the completion of construction would be managed in the EPC contract for such a facility. The IMO notes that the MRCP is based on a theoretical power station and may not reflect the specific risks and circumstances of individual projects. As the MRCP reflects the marginal cost of entry of new capacity, the IMO considers it inappropriate to include corporate overhead costs that may be associated with a single-asset company. The IMO also notes that the Margin M also includes a substantial allowance of 5% for Contingencies.
5	Perth Energy	Transmission connection cost	Transmission network connection costs continue to be unpredictable, depending mainly on the location a new project happens to be, and a significant contributor to the overall level of the MRCP. By using an average cost over the	The previous methodology employed by Western Power for 2012/13 and 2013/14 for estimating Transmission Connection Costs resulted in costs that were not reflective of the actual capital

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
			last 6 years this major input by definition is not a maximum. It would be better for IMO to take an average of the likely locations for generation capacity development as provided by Western Power (WP). At least this is forward looking, with WP recommending where the lowest cost locations are for a nominal peaking plant to connect to the Grid.	contributions being charged to project developers. The current methodology, first used for 2014/15, is based on a weighted average of actual capital contribution costs charged by Western Power to project developers.
6	Perth Energy	Transmission connection cost	PE would prefer to see a transmission connection cost methodology that reflects the location (and degree of constraint present) of the connection on the network and the type of load to be supplied. Such a change would see the connection costs charged to those users servicing the market as a whole being 'use of system' charges while those servicing special discrete loads would be charged on more of a user-pays, deeper connection, cost.	The current Transmission Connection Cost methodology is based on actual generation projects and thus takes account of the location and constraints applicable to actual projects. The methodology excludes generators where "the significant driver for the location of the facility is ... the need to embed the generation with a load (electrical or heat)" (step 2.4.1 of the Market Procedure. Such a generator may face increased connection costs that are not reflective of the costs for an efficient new entrant peaking generator. Further, the IMO considers it likely that a facility developed to serve a special discrete load would be bilaterally contracted with that load and hence would be unlikely to offer into a Reserve Capacity Auction.
7	Merredin Energy	Fixed Fuel Costs	In order to achieve practical completion and reserve capacity certification, a new power generator needs to complete successfully a series of commissioning tests to meet System Management requirements. This include 'cold commissioning' prior to the connection to the Western Power network and 'hot commissioning' which involves the dispatch of power to the grid. Merredin Energy consumed $2m worth of diesel fuel to comply with the minimum Western Power testing requirements for commissioning our 82MW plant. For a	The IMO notes that the MRCP is based on a theoretical power station and may not reflect the specific risks and circumstances of individual projects. The IMO has consulted with System Management, which is responsible for managing the interaction between the system and a commissioning generator. System Management has advised that it is common practice for the tests required by Western Power to be conducted in conjunction with

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
			160MW power station, the fuel costs would have totalled $4m. As a result of the IMO's capacity credit timetable, the majority of our commissioning had to be undertaken during the months of August and September, when energy prices are typically low. Merredin Energy earned a negligible $27,000 in STEM revenues from the generation of power during hot commissioning over the 2012 winter/spring period. The net fuel costs associated with commissioning had been ignored by SKM in its estimate of fixed fuel. The fixed fuel costs should increase by $4.0m for the notional 160MW power station.	the commissioning that is required under a typical EPC contract. The IMO notes that SKM has included a 2% allowance within Margin M for Start-up costs to cover costs including "*fuel and consumables used in testing and commissioning*". SKM's estimate is based on SKM's expertise from a range of projects with varying characteristics. Based on this information, the IMO considers that the allowance for Start-up costs is appropriate to cover the cost of fuel during commissioning. The IMO notes that the Reserve Capacity Mechanism places no limitations on the timing for plant commissioning. In the case of Merredin Energy, the Reserve Capacity Obligations for its Facility may have commenced at any time from 1 June to 1 October 2012, subject to the completion of commissioning.
8	Perth Energy	WACC	The current WACC methodology is inconsistent with investors' expectations of the risks involved in building and operating generation plant – we have attached a paper dealing comprehensively with issues associated with WACC determination and hope the IMO will be considering it appropriately.	The IMO considers that it is appropriate to determine the WACC in a way that is consistent with currently accepted Australian regulatory practice. Please refer to Section 3.6.2 of the Final Report for the 2014/15 MRCP for additional details.
9	Perth Energy	WACC	The effectiveness of the Reserve Capacity Price set using the administrative formula in the Market Rules is impaired by the approach adopted by the IMO to calculating WACC for the MRCP. The Capital Asset Pricing Model used by the IMO, if applied appropriately and calibrated against wider evidence, has the potential to be effective. However the approach currently adopted by the IMO does not meet	The IMO notes that it is standard regulatory practice in Australia to determine the WACC using the CAPM. See also response 8 above for additional detail. As noted in Section 5.1 of this report, the IMO considers that the formula for calculating the Reserve Capacity Price can be improved to deliver

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
			Market Objectives of: • promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS; and • encouraging competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors; because the WACC and MRCP that result from the IMO's approach: • does not result in an economically efficient price for the efficient, safe and reliable production and supply of electricity services in the SWIS; and • consequently does not provide pricing that facilitates efficient market entry and hence competition in the generation sector.	a more economically efficient capacity price and to send a sharper signal to investors when new capacity is required. Amendments to the RCP, in part to address this issue, are currently being considered by the RCMWG.
10	Perth Energy	WACC	The IMO sought advice from PriceWaterhouseCoopers (PwC) to inform its determination of WACC parameters. However, the terms of reference for advice it provided to PwC restricted the research to three WACC parameters and to regulatory decisions made by regulators subject to merit reviews. Accordingly, PwC was obliged to ignore regulatory decisions made by other economic regulators which may be appropriate to consider in the context of the decision on the MRCP. It seems important that the IMO should consider all information to ensure that the decision making approach is appropriate for the MRCP.	The Market Procedure obliges the IMO to "determine the methodology to estimate the DRP, which in the opinion of the IMO is consistent with current Australian accepted regulatory practice." PwC applied the same principle in its 5-yearly review of the WACC parameters, completed in 2011. As described in Appendix B of the Final Report for the 2014/15 MRCP, the IMO places emphasis on the acceptance of various methodologies. The IMO considers that a methodology is accepted if it has been challenged and the application of that methodology has been upheld. For this reason the IMO requested that PwC only consider regulatory decisions that were reviewable by the ACT when preparing its paper for presentation to the

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
				stakeholder workshop held on 1 November 2012. The IMO notes that it requested PwC to consider the cost of debt, the risk free rate and gamma for its recent paper for the stakeholder workshop. The IMO did not request new advice on other parameters as the 5-yearly review was completed in 2011 and no sustained shift in regulatory practice has been observed in relation to those parameters.
11	Perth Energy	WACC	The IMO approach includes parameter values carried over from previous reviews as well as parameters that are recalculated annually. Although, perhaps inconsistently with this approach, one of these "fixed" parameters, the gamma, was reviewed by PwC in its report due to a recent Australian Competition Tribunal (ACT) decision, which changed the value used by other Australian regulators. In particular, members of certain pairs of WACC parameters are interrelated. One member of the pair does not operate independently of the other. However, for two of the pairs, the IMO's approach holds the risk of internal inconsistency in its calculation of WACC because one member of a pair is updated and the other is not: • the risk free rate (updated annually by IMO) and the market risk premium (updated by IMO every five years); and • the debt risk premium (updated annually by IMO) and debt issuance costs (updated by IMO every five years).	The frequency of review of WACC parameters is stipulated in the Market Procedure. However the IMO considered it appropriate to propose an amendment to the value of gamma due to the ACT decision[23] and consistent use of a gamma value of 0.25 in subsequent regulatory decisions by the AER and the ERA. In its Final Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17 (April 2012), the AER stated that it "*considers that is incorrect to characterise the method for calculating these WACC parameters as a long term historical MRP coupled with a short term risk free rate. The risk free rate is not 'short term'. The risk free rate and MRP are both reflective of a forward looking return over the next 10 years. However, there are different considerations and evidence available for each parameter. The approach adopted by the AER is therefore internally consistent.*" The IMO supports this view. The IMO notes that a debt issuance cost allowance

[23] Application by Energex Limited (Gamma) (No 5) [2011] A CompT 9 (12 May 2011)

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				of 12.5 basis points has been standard Australian regulatory practice since before the 2007 review of WACC parameters conducted for the IMO by the Allen Consulting Group. For this reason PwC recommended in its 5-yearly review that this parameter be updated once every five years.
12	Merredin Energy	WACC	The IMO has reviewed only some of the existing WACC parameters, such as the gamma. It is poor public policy for the IMO to make judgement calls on which parameters to review and when. Best practice would see the IMO publish guidelines on that point. This would reduce the subjectivity present in the application of the current market procedures.	Please see response 11 above. The IMO notes that any amendment to the 5-Yearly WACC parameters may only be made through the Procedure Change Process, which includes public consultation.
13	Perth Energy	WACC	The IMO's approach focuses heavily on the WACC parameters, but not on the resulting WACC. WACC parameters are an input to a pricing outcome, not the outcome itself. The resulting WACC should be calibrated against expectations of industry norms and the objectives of the pricing regime, to help check test all the parameters are appropriate. For example, regulators in the United Kingdom and IPART commonly use financeability tests to determine whether the rate of return outcomes from the CAPM are consistent with regulators' obligations to balance the interest of investors and customers and to maintain the financial viability of regulated businesses. A financeability test examines the future cash flows that result from rate of return decisions and tests whether they enable a business to meet the regulator's assumed or target credit ratings and key financial ratios that measure financial viability and health. IPART has recently reaffirmed its commitment to using these tests as part of its approach to regulation going forward.	The IMO acknowledges that different regulators may follow different approaches in this area. Please see also response 10 above.

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14	Perth Energy	WACC	The CAPM is a widely accepted technique for calculating a benchmark rate of return for a business. While it is commonly used by access regulators to calculate regulated rates of return for monopoly businesses, there is no constraint on the use of CAPM for such businesses. The calculation of a WACC under the CAPM requires a range of specific input parameters to the CAPM to be determined. However, in deriving the input parameters for the WACC for the MRCP, the IMO has: • referred to regulatory precedents that apply to access regulated monopoly industries and services; and • drawn heavily on parameters and precedents applicable to network businesses. This does not appear appropriate or rational because: • reserve capacity is provided by the generation sector which normally operates in competitive markets. Precedents provided by commercial and market practice, not regulatory practice would be applicable; and • the operational and investment risks of generation businesses are significantly different to network businesses and revenue capped network businesses in particular. For example, generation businesses are subject to fuel price and supply risk and risks of competition and significantly greater volatility in demand and price.	The IMO agrees that the CAPM is widely used by regulators to calculate rates of return. The CAPM contains a mixture of market-wide parameters and industry-specific parameters. Further details can be found in PwC's 2011 report on the WACC for the MRCPWG[24]. Values for the industry-specific parameters are set to reflect common financing practices and to estimate the relative risks for a benchmark entity in the electricity generation industry. These parameters are the gearing ratio, credit rating (which is important in estimating the cost of debt) and beta. The IMO notes that it has applied different values for these industry-specific parameters than have been applied for electricity network businesses. For example Western Power's 2013-17 access arrangement uses a lower beta, higher gearing ratio and higher credit rating than are used for the MRCP.
15	Perth Energy	WACC	The IMO sets the price of generation capacity, not	See responses 10 and 14 above.

[24] Available at http://www.imowa.com.au/mrcpwg

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			transmission and distribution network services. The MRCP prices a fundamentally different service. Given the nature of the prices being regulated by the IMO, there may be some benefit in considering a wider pool of regulatory precedents in evaluating the appropriate level of the MRCP. For example, the IMO does not appear to have considered taking into account regulatory precedents for WACC for retailers, for regulated retail tariffs whose participation in wholesale electricity markets would indicate a risk profile closer to a generation business, than a network business. Examples include IPART's review of retail electricity tariffs in 2010 where it considered WACC for a retailer and a generator, and market observations on some WACC parameters for listed companies in Australia operating in the generation sector.	
16	Alinta Energy	WACC	Alinta continues to consider that a 'significant economic event' has occurred since PricewaterhouseCoopers (PwC) finalised its advice to the IMO and MRCP Working Group (MRCPWG) in February 2011 on the Weighted Average Cost of Capital (WACC) methodology. If anything, the evidence of a significant economic event is best illustrated by the recent market observations related to actual returns across a broad spectrum of securities. In particular there is a significant divergence between the rates for risky and non-risky assets in Australia; • Riskless securities such as government bonds have an artificially low rate as a result of foreign investors demand outstripping current supply; while • Risky assets such as bank debt have experienced an increasing cost of financing, as is evidence by the increased spread between bank borrowing and lending costs. Consequently, Alinta continues to request the IMO to exercise its discretion under the Market Procedure for the	The Market Procedure allows the IMO to 'review and determine values for the 5 Yearly components that differ from those in step 2.9.8 if, in the IMO's opinion, a significant economic event has occurred since undertaking the last 5 yearly review of the Maximum Reserve Capacity Price'. In section 3.6.3 of the Final Report for the 2014/15 MRCP, the IMO concluded that no significant economic event had occurred since the completion of the last 5-yearly review finalised in October 2011. Since that time there has been little change in the key Australian economic indicators that were considered at that time (GDP, CPI, the AUD-USD exchange rate and unemployment rate) and the ASX200 index has risen by 15% since the end of 2011. The IMO does not consider that there is compelling evidence to suggest that there has been a 'significant economic event' since the last review

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			determination of the Maximum Reserve Capacity Price (the Market Procedure) and re-examine the appropriateness of the prescribed five year values for the market risk premium (MRP) and equity beta used to calculate the WACC.	was completed in 2011.
17	Perth Energy	WACC – Risk Free Rate	The IMO has noted that its stakeholders consider that the current depressed values for the risk free rate is more a product of market characteristics (a flight to safety) than an appropriate estimate of the risk free rate that should be applied in the calculation of the WACC. PE considers there to be considerable support for a more long term approach to estimating the risk free rate under current market conditions. This support includes precedent and a recent Australian Competition Tribunal (ACT) decision, Application by EnergyAustralia and Others (No 2) [2009] ACompT9. In the ACT's decision, EnergyAustralia proposed an averaging period for determining the risk free rate that 'is closest to the regulatory control period prior to the emergence of the marked acceleration of the global financial crisis in September 2008'. This period was proposed on the basis that: • the AER's specified averaging period for observing key financial data is highly likely to include data that has been impacted by this supervening critical event; and • 'an averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return … which is materially biased below the rate of return required by investors in a similar commercial business'. The ACT upheld EnergyAustralia's appeal, and the averaging period proposed by EnergyAustralia was used in its final determination.	The IMO notes that Perth Energy has referred to a single decision by the ACT in 2009. However standard practice by the AER and ERA since that time has been to use a recent averaging period, typically being the last 20 business days of the preceding calendar month. The IMO will continue to monitor regulatory practice with regard to the selection of the averaging period for calculating the risk free rate. See also response 11 above.

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18	Perth Energy	WACC – Risk Free Rate	A further precedent for calculating the risk free rate which addresses this volatility is provided by SA Water in its recent pricing proposal, which proposed a 180 day observation period to average out the outliers and extend the sample size. In particular, SA Water mentioned that: • actual financing costs may differ significantly from those estimated under a 20 day averaging period; and • the 20 day averaging period does not take into account the potential variability in debt market conditions over the regulatory period. In the SA Water example, a 180 day averaging period to 1 June 2012 for a 10 year Commonwealth Government Bond provided a nominal risk free rate of 3.93 per cent.	The IMO notes that ESCOSA has yet to issue its draft decision in relation to SA Water's proposal. However, in its public consultation issues paper[25] ESCOSA states that its "*preference is to use a 20 day averaging period*".
19	Alinta Energy	WACC – Risk Free Rate	Alinta is concerned that the application of the risk free rate based on the current abnormally low yield on ten year Commonwealth Government bonds does not reflect the true risk free rate but rather is inappropriately depressed compared with its long run average value. Additionally, Alinta notes that once committed the development of generation assets are naturally long term investment decisions (30-40years). The development of an asset such as a power station is very costly and requires significant uncertainty of returns. Investors traditionally look to the capacity price to provide this certainty given the restrictions on bidding in the energy market (i.e. price caps and SRMC bidding requirements). Alinta continues to request to request that the IMO seek advice from an economic consultant to confirm whether:	The AER considered this issue in its *Final Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17* (April 2012) expressing their view that at "*times of uncertainty, investors are prepared to accept a lower yield on relatively safe assets*". The AER went on to state that "*an alternative explanation might be that CGS are currently 'over priced', in the sense that the price of CGS exceeds its fair value, and therefore the yield is 'artificially low', For the AER to make such a conclusion, the AER would, effectively, be saying that it has better information than the market or that it 'knows better' than the many traders in the market whose interactions set the price of CGS. The AER considers there is not a reasonable basis to draw such a conclusion on the evidence before it.*" The

[25] *Review of SA Water's Regulatory Business Proposal for the Revenue Determination Period 2013/14-2015/16, Public Consultation – Issues Paper, October 2012*

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			• Global structural imbalances have created an excess demand for Commonwealth Government Bonds which have subdued their observed price, thereby justifying an adjustment to the risk free rate; and • Longer term, the observed yield on government bond remains an acceptable proxy measure of the risk free rate.	IMO supports this view.
20	Perth Energy	WACC – Inflation	Perth Energy notes that the inflation is set at 2.57 per cent which is close to the mid point in the Reserve Bank of Australia target range of 2 per cent to 3 per cent. This is likely to be close to the outturn inflation rate due to the Reserve Bank's actions on adjusting interest rates. The forecast inflation rate is consistent with generally accepted economic forecasts.	The IMO notes Perth Energy's submission.
21	Perth Energy	WACC – Market Risk Premium (MRP)	In the past, Australian regulators consistently applied a market risk premium of 6 per cent. However, in its 2009 review of WACC parameters, the AER concluded that the market risk premium should be increased to 6.5 per cent on the basis of market conditions at the time. Nevertheless in its final decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, the AER used a market risk premium of 6 per cent for the gas business. In the ElectraNet draft decision (November 2012), the market risk premium was set at 6.5 per cent, consistent with the AER WACC review of May 2009, and consistent with ElectraNet's proposal. Murraylink, a single asset transmission interconnector also received a draft decision in November 2012 with an MRP of 6.5 per cent. This is consistent with 6.5 per cent allowed for ETSA Utilities more than two years ago in 2010. These decisions reflect the regulator's view that current market conditions remain inconsistent with normal, longer term market conditions and that a higher MRP is	The MRP of 6% used in the MRCP is stipulated in the Market Procedure. In the 5-yearly review of WACC parameters completed in 2011, PwC recommended "*a value of the MRP of 6.0 per cent taking into account an emerging regulatory position for a reversion to a long-standing position of adopting an MRP of 6.0 per cent after contemplating a higher value of 6.5 per cent for a period during and after the global financial crisis*". The IMO notes the recent AER decisions quoted by Perth Energy. The IMO also notes however that: • a MRP of 6% has been used in many AER decisions during 2012 including for SP Ausnet, the Roma to Brisbane Pipeline and Aurora; • the ERA has applied a MRP of 6% in its decisions for WAGN, the Dampier to Bunbury

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			warranted.	Pipeline and for Western Power; and • the ACT upheld an MRP of 6% in January 2012 in the application by Envestra Ltd for its SA and QLD gas networks. Consequently, the IMO does not consider that a sustained shift in regulatory practice has occurred in relation to the MRP. The IMO will continue to monitor regulatory practice and will develop a Procedure Change Proposal if a sustained shift in regulatory practice is observed. This is consistent with the IMO's approach to gamma in 2012.
22	Perth Energy	WACC – Market Risk Premium (MRP)	PE submits that the MRP should represent that component that, when applied in a CAPM, offers sufficient incentive for an investor to make efficient investment in new generation capacity in the WEM. Whilst PE acknowledges that the MRP is not business dependent, it seems difficult to understand how a more risky business operating in more difficult times might be fairly treated by an MRP which was less than that applied in a network business.	The IMO disagrees with Perth Energy's suggestion that the MRP should be set at a level so as to offer "*sufficient incentive for an investor to make efficient investment in new generation capacity in the WEM*". As Perth Energy noted in its submission, the MRP is a market-wide parameter that estimates the return that an investor requires above the risk free rate in order to accept average market risk. Please also refer to response 21 above.
23	Alinta Energy	WACC – Market Risk Premium (MRP)	Given PwC's comments (noted above), it reasonably follows that investors expected MRP will also have increased from 6% given the occurrence of a "significant economic event" resulting in greater levels of investment uncertainty. Alinta notes that other electricity regulators have applied higher MRP's in recent years. In particular, following its 2009 review of the WACC parameters the Australian Energy Regulator (AER) has been applying a MRP of 6.5% to transmission and distribution network determinations as reflected in its guideline document. This includes for recent draft determinations such as Electranet and Murraylink. Alinta notes that the AER adopted a value of 6.5% "having regard	See responses 16 and 21 above.

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			to the desirability of certainty and stability". Alinta recommends that in light of continued market evidence of a "significant economic event" having occurred and given that regulatory precedent of the AER, the IMO should consider adopt a MRP of 6.5%, as is applied by other regulators would be appropriate for determining the MRCP.	
24	Merredin Energy	WACC – Market Risk Premium (MRP)	We note PwC's advice to the IMO dated 19 October 2012 titled *Re: Summary of regulatory decisions related to Reserve Capacity Price* discussed the equity market risk premium (EMRP). Professor Robert Officer was quoted by PwC in that report, where Officer had made some good points in relation to the EMRP. We understand from PwC's correspondence that it agrees with Officer's stated position, particularly in respect of the risk free rate and EMRP needing to be set using consistent timeframes (either point in time or 'normalised levels'). Contrary to that advice, the current approach is uses inconsistent time periods, with normalised betas and EMRPs but a point in time parameter for the risk free rate. We suggest a review of the asset beta and EMRP is warranted immediately and prior to finalising the 2015-16 MRCP, particularly as the risk free methodology can not be changed barring an amendment to the market procedures. Given PwC's advice, who were engaged as an expert adviser to the IMO, the IMO should be duty bound to consider and act on that advice of 19 October. Such action should result in a higher and more appropriate EMRP. The recent academic paper *Adjusting the Market Risk Premium to Reflect the Global Financial Crisis* by Bishop, Fitzsimmons and Officer published in FINSIA's Journal of Applied Finance JASSA Issue 1 2011 found the market risk premium to be 9.7% based on the prevailing market volatility at the time of publication. Recognising the movement in markets since that	Please see responses 11 and 21 above.

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			date, an EMRP around 7% would be realistic today.	
25	Community Electricity	WACC – Debt Risk Premium (DRP)	We note the discussion of the relative merits of assessing the Weighted Average Cost of Capital via the cost of bank debt rather than through the corporate bond market. We support the continued use of the corporate bond approach on the grounds that it is the role of the IMO to follow established regulatory practice on such matters and no Australian regulator has used the cost of bank debt approach. It should also be remembered that: • the IMO's determination of the Maximum Reserve Capacity Price is subject to review by the ERA; • the Maximum Reserve Capacity Price is an estimate of the marginal cost of entry of additional Reserve Capacity in the applicable Capacity Year. While it is based on a benchmark power station, such a station probably does not exist in practice in respect of all elements and nuances of the benchmark. It is therefore necessary to assess the integrated package represented by the benchmark, and it is generally not appropriate to isolate for review particular aspects of it on a stand-alone basis without consideration of the interrelatedness with other aspects. [That said, we consider resetting the 'gamma' to be an exception as this is a supposedly fixed parameter in an accounting equation.]	The IMO notes Community Electricity's support.
26	Community Electricity	WACC – Debt Risk Premium (DRP)	We expressly support the application of the ERA's Bond Yield approach to determining the Debt Risk Premium component of the Weighted Average Cost of Capital.	The IMO notes Community Electricity's support.
27	Alinta Energy	WACC – Debt Risk Premium (DRP)	Alinta supports the use of the ERA's bond yield approach for the purposes of determining a WACC for an electricity generation business. However, Alinta considers that using an	The IMO notes Alinta's support for the use of the "Bond-Yield Approach" in determining the DRP. In the Draft Report for the 2015/16 MRCP the IMO

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			investment grade rating of BBB+ is inappropriate for generators in the WEM. The debt levels and riskiness of servicing that debt for electricity generators is significantly greater than for network generation businesses. Further, during the past few years' significant financial problems have been experienced by a number of the Market Generators in the WEM. Given recent experience Alinta questions whether any generators in the WEM (and more broadly Australia) currently have a BBB+ investment grade rating (or even a BBB investment grade rating). Alinta requests the IMO to undertake an assessment of the ratings of independently owned electricity generators in Australia to confirm an appropriate investment grade to be used for the purposes of the ERA's bond yield approach.	applied the "Bond-Yield Approach" as calculated by bonds with a credit rating of BBB and BBB+. This represented a strict application of the ERA's approach in the WAGN final revised decision. However, Step 2.9.7(h) of the Market Procedure requires the DRP to be determined from "*the observed annualised yields of Australian corporate bonds which have a BBB (or equivalent) credit rating*". Consequently the IMO has applied the "Bond-Yield Approach" as calculated from bonds with a BBB rating only in this Final Report.
28	Perth Energy	WACC – Debt Risk Premium (DRP)	The regulatory approaches reviewed by PwC for the IMO consider the debt risk premium for network businesses. This is not appropriate for the MRCP because it is required to reflect the cost of providing reserve generation capacity rather than a monopoly network system.	The methodologies examined by PwC have estimated the debt risk premium from observations of corporate bond yields of a particular benchmark credit rating. As noted in the advice from PwC[26] the DRP has been calculated from observed yields of a selection of corporate bonds with a credit rating of BBB with a term to maturity of at least 2 years. Table 2 in PwC's letter shows that the selected bonds have been issued by a range of companies in various industries including gas pipelines, airports, cement and property.
29	Perth Energy	WACC – Debt Risk Premium (DRP)	In addition, the IMO's Draft Determination notes that stakeholders have suggested that they are more likely to access bank financing rather than corporate debt market	In its review for the stakeholder workshop held on 1 November 2012, PwC stated that "*with respect to the issue of assessing the cost of bank debt, we*

[26] http://www.imowa.com.au/f175,3075586/20121011_IMO_-_PwC_Debt_risk_premium_Final.pdf

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			financing. In network price regulation, debt market financing is used because it is assumed that the regulated businesses have access to these markets. It would be reasonable to assume that network businesses would have access to debt markets. However, it may not be axiomatic that this is also true for a less capital intensive business such as a benchmark provider of Reserve Capacity. There are regulatory precedents for this, which appear more relevant than the large network business precedents on which the IMO has drawn. It would be appropriate for the IMO to consider this matter and its impact on the debt risk premium.	*note that as far as we are aware, no Australian regulator has applied a cost of debt estimate that is based on a measure of the cost of bank debt*." The IMO notes that BBB is the lowest credit rating that is considered "investment grade". In addition to the review by PwC, the IMO separately consulted with banks to determine whether banks maintained a robust benchmark or index of the cost of debt that was publicly available. The banks contacted confirmed that the cost of bank debt was determined on a project-by-project basis and that no such benchmark was publicly available.
30	Perth Energy	WACC – Debt Issuance Costs	While using a consistent level for some parameters over time is a well accepted approach to price regulation (for example, the market risk premium is often kept stable over time by regulators), it seems reasonable to question whether debt issuance costs should be left fixed while the debt risk premium is calculated annually. In times of uncertainty, the costs of issuing debt can vary. This may coincide with large changes in the debt risk premium. Given the potential for debt issuance costs to vary, there may be a benefit in calculating the debt.	See response 11 above.
31	Community Electricity	WACC - Gamma	We expressly support resetting the imputation credit ("gamma") value to 0.25 in line with current Australian regulatory practice.	The IMO notes Community Electricity's support.
32	Perth Energy	WACC – Gamma	PE submits that the move from a gamma of 0.5 to 0.25 recognises that there are different investors participating in the market and that international investors and others do not value franking credits in the same way as an Australian	The financing parameters used within the WACC are based on the assumption that finance is sourced within Australia. This is consistent with the use of Australian benchmarks for other WACC

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			resident taxpayer. The adoption of a gamma of 0.25 in the Australian Competition Tribunal decision recognises the reduction in value of franking credits attributed to a mix of equity providers. It is noted that there are many instances of Australian generation businesses with foreign ownership to support the notion that franking credits should be valued at the lower end of the scale. Given that the generation sector is more likely to need foreign investment to satisfy the equity needs for a new generation project, the gamma should be zero, or at least approach zero to offer sufficient incentive to maintain access to the necessary capital and provide benefits of competition in the WA generation market.	parameters including the risk free rate, inflation, Debt Risk premium and the Corporate tax rate. It is not Australian regulatory practice to determine WACC parameters on the assumption that finance is obtained outside of Australia.
33	Perth Energy	WACC – Beta	In its 2009 WACC Review (for network businesses), the AER changed its previously held position on the value of the equity beta for electricity distribution and transmission businesses from 1.0 to 0.8. Because the AER WACC review sets some parameters for a period until the next WACC review, the equity beta applied in the recent ElectraNet draft decision was 0.8 (November 2012). This was applied to a business with approximately $2 billion in assets, operating a monopoly transmission business under a revenue cap approach. This is therefore a significantly less risky business with more stable revenue streams than a generation business supply reserve capacity. The question of whether it is appropriate to use the equity beta applied to distribution and transmission businesses in a process to determine an MRCP in WA depends on an assessment of whether there is a difference in the systemic risk faced by network monopolies as compared to generation businesses. Reasons for any differences are primarily due to the nature of activities undertaken by the businesses and the	The beta used in the MRCP is stipulated in the Market Procedure. The value of beta was assessed by PwC in its 5-yearly review for the MRCPWG, through examination of a wide range of comparator companies in the electricity generation industry. PwC's analysis and recommendation was based on the assumption in Step 2.9.1 of the Market Procedure that the power station "is assumed to receive capacity credits through the Reserve Capacity Auction and be eligible to receive a Long-Term Special Price Arrangement".

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			costs incurred.	
34	Alinta Energy	WACC - Beta	During the past four years electricity generators have experienced far more volatility than the market as a whole. This is evidenced by the recent significant reductions in electricity demand in the eastern states that have occurred in isolation from a reduction in economic growth. Likewise in Western Australia actual demand for energy has not been as high as was originally predicted given that a number of large loads were assumed in the Statement of Opportunities did not eventuate. Other factors resulting in volatility in the WEM include: • Significant variations in the Reserve Capacity Price that have created significant concerns for investors around expected returns on both new and existing generation assets; • The impact of a Demand Side Management (DSM) on the Reserve Capacity Price, i.e. significant entry of DSM into the market over the last few years has contributed to an oversupply of capacity; • Significant cost to Market Generators of operating in the new Balancing and Load Following markets; • Increases in the penetration of renewable energy technologies have resulted in reduced overnight prices which have on occasions caused base load facilities to turn off over night and have changed requirements for Ancillary Services; • Uncertainty created by the Rule Change Process; • Lack of investment by the private sector in recent times in the WEM except in joint venture with Government, e.g. Vinalco, Mumbida wind farm, Greenough River Solar Farm. Given the volatility in the operating environment for electricity	See response 33 above.

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			generation assets in Australia and specifically Western Australia, Alinta considers that the current value for the equity beta is inappropriate and resulting in a "non-real world" WACC outcome. Even at the assumed gearing levels, an equity beta of less than one does not adequately reflect the volatility in expected returns and therefore the relative riskiness faced by a standalone generator in Western Australia. An equity beta of less than one may be appropriate for an existing state owned base load generator however the risk profile is significantly greater for a privately funded new entrant electricity generator. As the MRCP based on the development of a new 160MW Open Cycle Gas Turbine, Alinta considers it is appropriate to assume the higher risk profile would apply. While the overall impact on the nominal return on equity is as a result of a combination of parameters, including the risk free rate of return and MRP (both discussed in this submission), Alinta considers that the IMO should engage an economic consultant to re-examine the equity beta given that it does not adequately reflect the riskiness of investment in a generator in the WEM.	
35	Merredin Energy	WACC - Beta	We consider that financiers will be continue to be concerned by the volatility of MRCP changes and this will, in turn, increase the cost of funding. This volatility should feed into the asset beta and the WACC. We note that no justification for retaining an asset beta of 0.5 has been provided. This number was based on dated historical data that is unreflective of the risks associated with constructing and operating a WEM peaking generation plant. We suggest an asset beta should be at least 0.6 based on the analysis presented in our previous submissions to the IMO.	Please see responses 3 and 33 above.
36	Merredin	WACC -	The expected rate of inflation (parameter (i)) should be derived from the difference in nominal and inflation linked	Step 2.9.7(k) of the Market Procedure requires that the value of the inflation parameter be determined

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	Energy	Inflation	bond yields published by the RBA, rather than taking a single one year projection of 3.25% and nine years of 2.5% which is largely an arbitrary assumption. The IMO's existing methodology is inconsistent with the market procedure as the RBA has not published specific inflation forecasts out to 2022. Using RBA published bond yield data for bonds maturing in 2022, without interpretation or extrapolation, would be consistent with the market procedures and give a more sensible expected inflation result. Based on RBA published bond yield data (as underpinned in Graph 5.9 of the RBA's Statement on Monetary Policy November 2012), long term expected inflation (parameter (i)) should be 2.1%.	with "*regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.*" The IMO considers that it has determined the value of the inflation parameter in accordance with the Market Procedure. The IMO notes that the recent RBA forecasts of CPI inflation are 2-3% for the 2013/14 financial year and the 2014 calendar year[27]. Analysis in a recent discussion paper published by the RBA[28] supports the use of the mid-point of the RBA's target range of inflation for the outer years: "*At horizons over which monetary policy has a substantial influence, deviations of inflation from the target should generally be unpredictable. If there were predictable deviations, it would mean that the central bank was expecting that it would miss its target and was not acting to prevent this.*"
37	Perth Energy	WACC – Gearing Ratio	The debt to equity ratio assumed by the IMO appears more consistent with the generation sector, albeit with a higher debt ratio than is experienced in the sector.	The IMO notes Perth Energy's submission. The gearing ratio is stipulated in the Market Procedure. The IMO notes that PwC, in its review for the MRCPWG, recommended that the gearing ratio be reduced from 40 per cent to 35 per cent based on observations from the list of comparator companies in the electricity generation industry. However, the MRCPWG advised that gearing ratios for Market Participants in the SWIS were likely to be higher

[27] Statement on Monetary Policy, November 2012
[28] Available at http://www.rba.gov.au/publications/rdp/2012/2012-07.html

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				than this and that it was appropriate to retain a gearing ratio of 40 per cent for the MRCP.
38	Merredin Energy	Fixed O&M	Merredin Energy has recently entered into an O&M agreement and a separate energy dispatch services agreement. The cost of the energy dispatch services is a fixed annual fee of $200,000 regardless of the GWhs generated. The costs of the energy dispatch services have been completely ignored by SKM. The services are necessary in order to comply with the new balancing market regime including lodging all STEM and balancing bids, commissioning, testing, outage and other notices. We have engaged Perth Energy to provide energy dispatch services and understand it is the only business that provides such services to independent generators. Accordingly, the fixed O&M costs in the MRCP must be increased by $200,000. If the IMO is minded to continue ignoring those costs, we call on the IMO to make that service available to generators free of charge.	The cost described by Merredin Energy relates to its interaction with the energy market. The IMO considers that such a cost should be compensated through the energy market. Further, the Market Procedure does not make specific allowances for the cost of operational interaction with the Market as it is envisaged that these will be limited for a peaking plant that operates infrequently. Market Participants may submit standing offers into both the STEM and the Balancing Market. The IMO notes that the MRCP is based on a theoretical power station and may not reflect the specific risks and circumstances of individual projects. As the MRCP reflects the marginal cost of entry of new capacity, the IMO considers it inappropriate to include such corporate overhead costs that may be associated with a single-asset company.
39	Merredin Energy	Fixed O&M	We note very little supporting information has been provided by SKM on the O&M components generally. We consider the general O&M costs including the allocations to plant operator labour and corporate overheads to be substantially understated. It might be useful for a further analysis of the O&M costs be undertaken prior to setting the final MRCP. It would also be useful for SKM to consider the costs associated with staying abreast of and complying with changes to the WEM procedures in the O&M costs.	SKM has provided for $2.2M in annual O&M costs in its report with a high-level breakdown, to which are added insurance and network access charges (a further $2.8M). The IMO notes that SKM's estimates are based on SKM's expertise from a range of projects with varying characteristics, not from a deterministic calculation. The IMO notes that the MRCP is based on a theoretical power station and may not reflect the specific risks and circumstances of individual projects. As the MRCP reflects the marginal cost of entry of new capacity, the IMO considers it

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
				inappropriate to include corporate overhead costs that may be associated with a single-asset company.
40	Merredin Energy	Fixed O&M	SKM estimated the annual costs of EPA charges and emissions tests to total only $32,000. We would certainly welcome the opportunity for SKM to complete that work for Merredin at a fixed fee of that amount! The cost of burning diesel for compliance tests should be included in the consent costs. Expected STEM revenues earned from the testing regime could be netted off the costs, although those revenues are likely to be negligible (as discussed above in relation to the commissioning costs). The consent cost parameter should also include the costs associated with maintaining and renewing generation licences and compliance with the Clean Energy Act (Cth) which is a recent additional obligation placed on generators.	The IMO considers that a prudent generator will endeavour to schedule any requirement for the testing of a facility to meet Reserve Capacity Test requirements, at the same time as any other regulatory or operational requirements to operate the facility. As the MRCP reflects the marginal cost of entry of new capacity, the IMO considers it inappropriate to include corporate overhead costs.
41	Community Electricity	Fixed O&M – Network Access Charges	We expressly support using the approved Network Access Price List in determining the network access charges, including any adjustments as necessary.	The IMO notes Community Electricity's support.
42	Merredin Energy	Fixed O&M – Insurance Costs	Merredin Energy recently placed asset replacement and business interruption insurance with Chartis. As part of that process, Chartis required that we commission a site survey annually. Chartis quoted $20,000 cost of the initial survey it was to conduct, with the survey cost charged to Merredin Energy. While that is only a modest cost in the scheme of insurance, we recommend the costs of annual insurance surveys be incorporated in the MRCP.	The IMO has consulted with a well-known insurance broker in relation to site surveys for the placement of insurance. This broker has confirmed to the IMO that it is common practice to for insurers to require that a site survey be completed before offering insurance. The IMO has included an allowance of $20,000 to meet the cost of performing an annual site survey.
43	Merredin Energy	Fixed O&M – Insurance	The sums insured are not specifically identified but can be inferred. For asset replacement and business interruption	The IMO has consulted with a well-known insurance broker in relation to the insurance of fuel. This broker has confirmed to the IMO that it is

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
		Costs	insurance the sum insured should be increased to include: • $743,800 worth of liquid fuel stored on site. Stored fuel is a valuable commodity and in the event of a total loss, the insurer should be expected to meet the cost of refilling tanks. We remain perplexed as to why any owner of a power station would elect to exclude that from the sum insured. • Following a total loss event and the rebuild of the plant, further commissioning and testing work would need to be undertaken. The costs of burning diesel to complete the commissioning work would ordinarily be borne by the insurer and therefore needs to be included in the sum insured. Based on Merredin Energy's recent commissioning experience (discussed earlier in this submission) we calculate the increase to the sum insured to be $4.0m for this item. • The costs of debris removal and decontamination expenses should also be included in the sum insured.	common practice to insure the fuel stock. Consequently, the IMO has increased the assumed limit of liability in its calculation of the asset replacement and business interruption insurance cost to include the full Fixed Fuel Cost. The IMO notes that the assumed limit of liability includes all costs covered by margin M (18.77% of EPC). Margin M includes allowances for commissioning and testing of plant. The IMO considers that some of the costs covered by margin M would not be required to be paid in the event of a total loss event (such as the cost of raising capital and environmental approvals), while some additional site preparation may be required. On balance, the IMO considers that the assumed limit of liability would provide adequate coverage for a total loss event. The IMO also notes that the Margin M also includes a substantial allowance of 5% for Contingencies. In its report, SKM indicates that this allowance may include a range of costs including "*removal of debris or contamination*".
44	Merredin Energy	Fixed O&M – Insurance Costs	Merredin Energy's business interruption insurance policy has a 30 day deductible period. We would encourage the IMO to consider applying a lower deductible and increase the premium. If the IMO remains minded to maintain a 60 day deductible period (or $4.3m), we would argue it is duty bound to include an allowance for the costs of forced outage refunds to reflect the cost of this self insurance. We would suggest a forced outage of two months for each 30 years of operations (i.e. an average cost of $143,000 pa or 0.06% of the business interruption sum insured).	The IMO notes that the estimate of business interruption insurance costs in the 2012 MRCP was based on a 45-day deductible period. However, the in consulting with well-known insurance brokers the IMO received advice that it has become common practice for power station operators to have a 60-day deductible period. As noted in response 34 above, the MRCP is based on a theoretical power station and may not reflect the specific risks and circumstances of individual

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
				projects.
45	Merredin Energy	Fixed O&M – Insurance Costs	Any prudent owner of a power station should also maintain minimum workers compensation cover and pollution liability insurance. Pollution liability insurance covers the risks associated with the gradual leakage of diesel from the storage tanks and is essential for a power station owner with 815kL of diesel continually stored on site. These risks can lead to material financial losses and are not covered by standard asset replacement or business interruption insurance. The premia associated with these policies is should be added to the annual insurance costs.	The IMO notes Merredin Energy's comments. In relation to workers compensation insurance, the MRCP reflects the marginal cost of entry of new capacity and hence the IMO considers it inappropriate to include corporate overhead costs. Step 2.5.3(b) of the Market Procedure stipulates that the MRCP is to include estimated insurance costs "*in respect of power station asset replacement, business interruption and public and products liability insurance*". This precludes the inclusion of an allowance for pollution liability insurance. The IMO will discuss this issue with the MAC in 2013. The IMO suggests that Merredin Energy make a submission to the ERA as part of its upcoming review (as required under MR 2.26.3).
46	Verve Energy	Capacity Refund Allowance	As part of the submissions process on the Five-Yearly Review of the Methodology and Process for Determining the MRCP (PC_2011_06) Verve Energy noted a concern that the non-inclusion of an adjustment for Forced Outage rates in the MRCP formula could have a serious financial impact, even for plants with a relatively low Forced Outage rates. Verve Energy's full submission on this is available on the IMO's website. In response to this concern the IMO noted that: "…an allowance for Forced Outages should be reconsidered in the future, based on analysis of market data following the implementation of any changes to the Reserve Capacity refund regime, which are expected to be significant…"	The IMO notes Verve's comments. The IMO will discuss this issue with the MAC in 2013. The IMO suggests that Verve Energy make a submission to the ERA as part of its upcoming review (as required under MR 2.26.3).

No.	Submitter	Component/ Issue	Comment/Change Requested	IMO's response
			Verve Energy is aware that, as part of the Reserve Capacity Mechanism Working Group's deliberations, there has been an in principle agreement regarding the concept of adopting a dynamic refund mechanism. As such, Verve Energy requests that the IMO add a review of "the potential inclusion of an adjustment for Forced Outages in the MRCP calculation" into its work plan. Verve Energy requests that this review to commence six months after the implementation of a dynamic refund mechanism.	

6. CONCLUSION

The IMO has conducted a review of the main factors used to determine the MRCP, in accordance with the Market Procedure.

For the 2013 Reserve Capacity Cycle, the IMO proposes that the MRCP be set at $157,000 per MW per year.

The MRCP of $157,000 per MW per year represents a decrease of 4.2% from the 2012 MRCP. The main drivers of the lower MRCP have been the reduction in WACC as well as a net decrease in capital costs related to the Power Station and Fixed Fuel Costs.

The 2013 MRCP computation has been included in Appendix B and a comparison between the 2012 and 2013 MRCPs can be found in Appendix C.

APPENDIX A: WEIGHTED AVERAGE COST OF CAPITAL (WACC)

The pre-tax real Officer WACC is used for the determination of the Maximum Reserve Capacity Price. The formulae are shown below:

$$WACC_{real} = \left(\frac{(1 + WACC_{nominal})}{(1+i)} \right) - 1$$

and

$$WACC_{nominal} = \frac{1}{(1 - t(1-\gamma))} R_e \frac{E}{V} + R_d \frac{D}{V}$$

where the nominal Return on Equity is calculated as:

$$R_e = R_f + \beta_e \times MRP$$

and the nominal Return on Debt is calculated as:

$$R_d = R_f + (DRP + d)$$

Pricewaterhouse Coopers (PwC) calculated the debt risk premium and the IMO reviewed the remaining Annual parameters. A table of the parameters and values are shown in Table A1 below. The volatile Minor parameters, highlighted in yellow, have been recalculated since the publication of the final report so that the most recent numbers are used.

Table A1: WACC parameters for 2012 and 2013

Parameter	Notation	2013 Value	2012 Value
Nominal Risk Free Rate of Return (%)	R_f	3.14	3.92
Expected Inflation (%)	i	2.57	2.55
Real risk free rate of return (%)	R_{fr}	0.55	1.34
Market Risk Premium (%)	MRP	6	6
Asset beta	β_a	0.5	0.5
Equity beta	β_e	0.83	0.83
Debt Margin / Debt Risk Premium (%)	DRP	2.71	4.13
Debt issuance costs (%)	d	0.125	0.125
Corporate tax rate (%)	t	30	30
Franking credit value	γ	0.25	0.5
Debt to total assets ratio (%)	D/V	40	40
Equity to total assets ratio (%)	E/V	60	60

For the purposes of the 2013 MRCP:

WACC = 5.95%

APPENDIX B: CALCULATION OF THE MAXIMUM RESERVE CAPACITY PRICE

The Maximum Reserve Capacity Price is calculated as described by the *Market Procedure: Maximum Reserve Capacity Price*. This is shown below:

MRCP = ANNUALISED_FIXED_O&M + (ANNUALISED_CAP_COST / CC)

where:

MRCP is the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction.

ANNUALISED_FIXED_O&M is the annualised fixed operating and maintenance costs for the power station and any associated electricity transmission facilities, expressed in Australian dollars, per MW per year.

ANNUALISED_CAP_COST is the CAPCOST, expressed in Australian dollars, annualised over a 15 year period using the Weighted Average Cost of Capital (WACC).

CC is the expected Capacity Credit allocation determined in conjunction with the power station capital cost, expressed in MW.

Table B1: 2013 MRCP and associated parameters

Parameter	Value	Unit
2012 MRCP	**$157,000.00**	**A$/MW/Year**
Where		
ANNUALISED_FIXED_O&M	$34,238.67	A$/MW/Year
ANNUALISED_CAPCOST	$19,599,805.92	A$/Year
CC	159.6	MW

Table B2: ANNUALISED_CAPCOST and associated parameters

Parameter	Value	Unit
CAPCOST	**$190,938,543.97**	**A$**
Where		
PC	$829,446.75	A$/MW
M	18.87%	%
TC	$115,124.00	A$
CC	159.6	MW
FFC	$7,069,232.08	A$
LC	$2,693,872.28	A$
WACC	5.95%	%
Annualisation		
ANNUALISED_CAPCOST	**$19,599,805.92**	**A$/Year**
Where		
CAPCOST	$190,938,543.97	A$
WACC	5.95%	%
Term of Finance (Years)	15	Years

Parameter	Value	Unit
CAPCOST	**$190,938,543.97**	**A$**
Where		
PC	$829,446.75	A$/MW
M	18.87%	%
TC	$115,124.00	A$
CC	159.6	MW
FFC	$7,069,232.08	A$
LC	$2,693,872.28	A$
WACC	5.95%	%
Annualisation		
ANNUALISED_CAPCOST	**$19,599,805.92**	**A$/Year**
Where		
CAPCOST	$190,938,543.97	A$
WACC	5.95%	%
Term of Finance (Years)	15	Years

APPENDIX C: COMPARISON BETWEEN THE 2012 AND 2013 MAXIMUM RESERVE CAPACITY PRICES

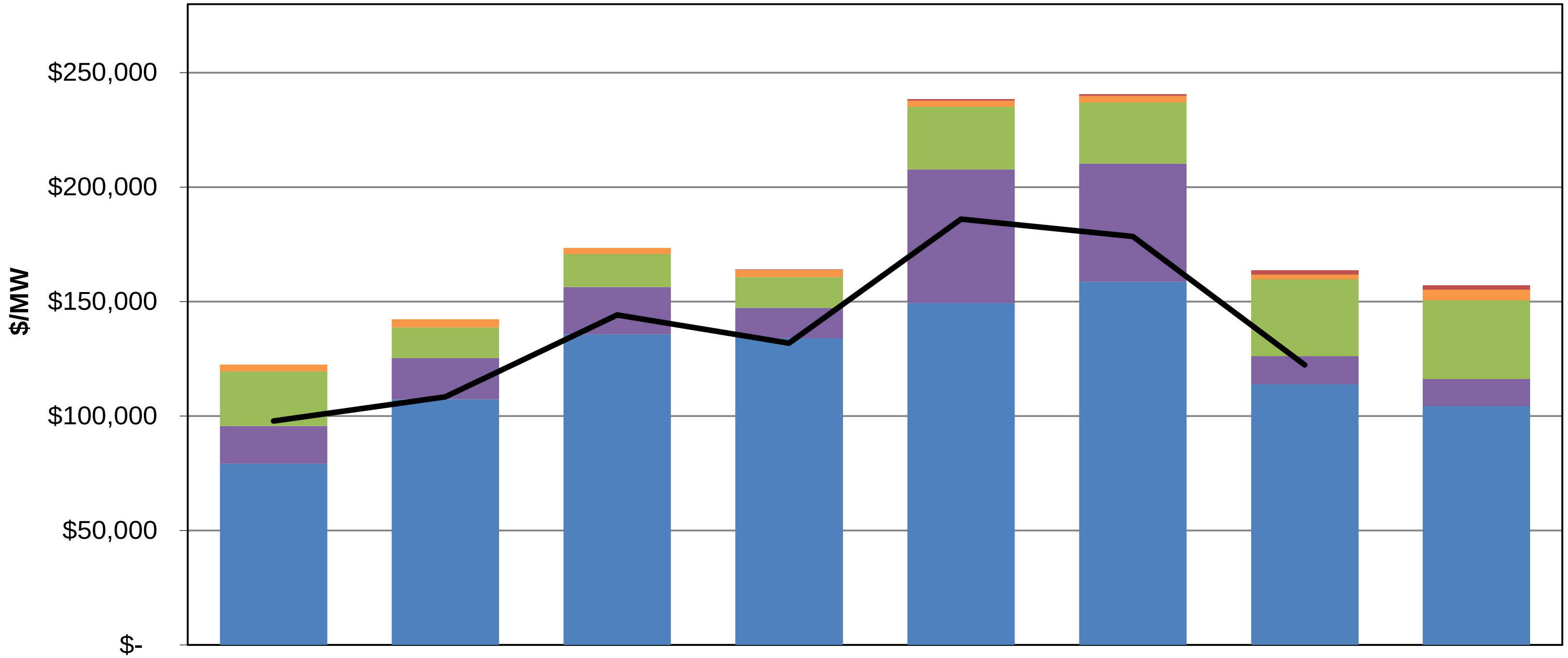
Table C1: Comparison between 2012 and 2013 MRCPs

Parameter	Reserve Capacity Year 2013	2012	Units
PC	$829,446.75	$858,987.37	A$/MW
M	18.87%	18.2%	%
TC ($/MW)	$115,124.00	$109,821.00	A$/MW
FFC	$7,069,232.08	$3,183,074.82	A$
LC	$2,693,872.28	$2,804,181.83	A$
CAPCOST	$190,938,543.97	$191,790,889.30	A$
Term of Finance	15	15	Years
WACC	5.95%	6.83%	%
ANNUALISED_CAPCOST	**$19,599,805.92**	**$20,829,728.91**	**A$/Year**
CC	159.6	159.6	MW
ANNUALISED_CAPCOST	$19,599,805.92	$20,829,728.91	A$/Year
ANNUALISED_FIXED_O&M	$34,238.67	$33,391.76	A$/MW/Year
MRCP	**$157,000.00**	**$163,900.00**	**A$/MW/Year**

Table C2: Impact of year-on-year changes in input parameters

	Impact ($)	Impact (%)	MRCP ($)
2014/15 MRCP			**163,900**
Escalation factors	+ 400	+ 0.2%	164,300
Power Station costs	- 4,300	- 2.6%	160,000
Margin M	+ 600	+ 0.4%	160,600
Fixed Fuel Cost	+ 2,800	+ 1.7%	163,400
Land Cost	- 100	- 0.1%	163,300
Transmission Cost	+ 600	+ 0.4%	163,900
WACC	- 7,700	- 4.7%	156,200
Fixed O&M	+ 800	+ 0.5%	157,000
Combined impact	**- 6,900**	**- 4.2%**	**157,000**

APPENDIX D: VARIATION IN THE MAXIMUM RESERVE CAPACITY PRICE AND CONSTITUENT COSTS



Capacity Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Power Station Cost	$ 79,110	$ 107,404	$ 135,701	$ 134,091	$ 149,306	$ 158,710	$ 113,971	$ 104,178
Transmission Costs	$ 16,558	$ 18,017	$ 20,672	$ 13,151	$ 58,493	$ 51,621	$ 12,329	$ 12,164
Fixed O& M	$ 23,900	$ 13,363	$ 14,392	$ 13,431	$ 27,335	$ 26,649	$ 33,384	$ 34,239
Fuel Costs	$ 2,907	$ 3,456	$ 2,631	$ 3,151	$ 2,615	$ 2,825	$ 2,239	$ 4,680
Land Costs	$ -	$ -	$ -	$ 293	$ 769	$ 818	$ 1,973	$ 1,783
MRCP (nearest $100)	$ 122,500	$ 142,200	$ 173,400	$ 164,100	$ 238,500	$ 240,600	$ 163,900	$ 157,000
Excess Capacity	6.43%	11.44%	2.19%	5.83%	8.99%	14.59%	13.79%	-
Reserve Capacity Price (per yr)	$ 97,837	$ 108,459	$ 144,235	$ 131,805	$ 186,001	$ 178,477	$ 122,427	-

APPENDIX E: ABBREVIATIONS

ACT – Australian Competition Tribunal

AER – Australian Energy Regulator

CAPM – Capital Asset Pricing Model

CPI – Consumer Price Index

DRP – Debt Risk Premium

ERA – Economic Regulation Authority

GDP – Gross Domestic Product

GST – Goods and Services Tax

IMO – Independent Market Operator

MRCP – Maximum Reserve Capacity Price

MRCPWG – Maximum Reserve Capacity Price Working Group

MRP – Market Risk Premium

MW – Megawatt

OCGT – Open Cycle Gas Turbine

O&M – Operation and Maintenance

PwC – Pricewaterhouse Coopers

RBA – Reserve Bank of Australia

SKM – Sinclair Knight Merz

SWIS – South West interconnected system

WACC – Weighted Average Cost of Capital

WEM – Wholesale Electricity Market

Landgate

Your Ref:	RSC181
Our Ref:	Job:136467 (DC:RS) File:29425-2010
Enquiries:	Darren Criddle Ph: 9273 9026
E-mail:	darren.criddle@landgate.wa.gov.au

11 September 2012

Independent Market Operator
Manager System Capacity
PO Box 7096 Cloisters Square
PERTH WA 6850

FOR THE ATTENTION OF MR GREG RUTHVEN

Dear Mr Ruthven

LAND VALUES FOR RESERVE CAPACITY PRICE

Further to your e-mail instructions from Mr Johan van Niekerk and Mr Greg Ruthven of the Independent Market Operator, I have prepared the following assessments on the notionally proposed sites listed below as at the 30 June 2012.

ASSESSMENT INSTRUCTIONS

Instructions have been received from Mr Johan van Niekerk "Independent Market Operator", requesting unimproved market assessments for hypothetical land sites suitable for the development of a power plant, in the following nominated regions.

As per our previous report dated 29 September 2011, we have been requested to provide value estimates for hypothetical sites in the Kwinana and Pinjar areas (metropolitan region) and Collie, Kemerton Industrial Park, Geraldton, Eneabba and Kalgoorlie regions.

With regard to all regions; the assessments are based on a hypothetical 3 hectare site or the minimum land area required should that be greater than 3 hectares.

- Pinjar Region (3 hectare site)
- Kwinana Region (3 hectare site)
- Kemerton Industrial Park Region (5 hectare minimum site)
- Collie Region (3 hectare site)
- Geraldton Region (3 hectare site) – North Country Region
- Eneabba Region (3 hectare site) – North Country Region
- Kalgoorlie Region (3 hectare site)

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Western Australian Land Information Authority ABN 86 574 793 858

The assessments are based on the following,

- No specific sites have been identified.
- The hypothetical land sites are generic for each region and have no distinct beneficial or detrimental features that would affect the development of a power station or their inherent value as a power station site.
- The hypothetical land sites are within or near to existing industrial estates or land that would be suitable for and permit the development of a power station.

REGION SUMMARIES

PINJAR REGION

The suburb of Pinjar is located approximately 30 kilometres north of the Perth CBD. Much of the area is State Forest and a water catchment area with some land reserved for public purpose, parks and recreation and rural land. Neighbouring land to the south west of Pinjar has a variety of different land uses from rural to residential and includes the Meridian Park industrial estate in Neerabup.

Analysis of industrial land sales in Neerabup, Wangara, Landsdale and Gnangara show levels for lots of approximately 3 hectares in the range of **$1,500,000 to $2,000,000** per hectare. This is the same range as advised in our 2011 assessment, however evidence indicated levels should be adjusted toward the lower end of this range.

KWINANA REGION

The Kwinana industrial area is located approximately 30 kilometres south of the Perth CBD and adjoins both Naval Base and East Rockingham industrial areas overlooking Cockburn Sound.

Kwinana is an established industrial location with all essential services available and good access to Perth CBD, port facilities and the South-West region of the state.

Analysis of industrial land sales in Kwinana and surrounding areas show levels for lots of approximately 3 hectares in the range of **$2,000,000 to $2,750,000** per hectare. This range has been extended at the lower limit from our 2011 advice and our assessment adjusted accordingly.

KEMERTON INDUSTRIAL PARK REGION

Kemerton Industrial Park is located approximately 17 kilometres north east of Bunbury and 160 kilometres south of Perth.

Kemerton Industrial Park was established in 1985 for heavy industry and has good access to the South-West region, Rockingham, Kwinana and Perth. Information gathered from the Kemerton Strategic Plan and the City of Bunbury's Planning Services indicate that the minimum lot size within the Kemerton Industrial Park is 5 hectares.

Information and evidence gathered in the Kemerton Industrial Park and the surrounding region show levels for lots of approximately 3 hectares in the range of **$225,000 to $275,000** per hectare. This has remained unchanged from our 2011 assessment.

COLLIE REGION

The town of Collie is located approximately 200 kilometres south east of Perth. Major industries that support the town include coal mining, farming and forestry.

Information and evidence gathered for land suitable for the development of a power plant in the Collie region, but not in the town site show levels for lots of approximately 3 hectares in the order of **$100,000** per hectare. This has remained unchanged from our 2011 assessment. (Industrial 3 hectares sites inside of the Collie townsite show levels in the range of $150,000 per hectare).

GERALDTON REGION

Geraldton is located approximately 425 kilometres north of Perth. Geraldton is a key port and administrative centre for the mid west region. Major industries that support the city include tourism, agriculture, fishing, mining and trade.

Analysis of land sales suitable for the development of a power plant in the Geraldton region show levels for lots of approximately 3 hectares in the order of **$150,000** per hectare. This has remained unchanged from our 2011 assessment.

ENEABBA REGION

The town of Eneabba is located approximately 300 kilometres north of Perth. The town services the surrounding agricultural industry and the nearby mineral sands facility.

Information and evidence gathered show levels for lots of approximately 3 hectares suitable for the development of a power plant in the region surrounding Eneabba in the order of **$40,000** per hectare. This has remained unchanged from our 2011 assessment.

KALGOORLIE REGION

Kalgoorlie is located approximately 595 kilometres east of Perth. Kalgoorlie is the administrative centre for the eastern Goldfields region. Major industries that support the city include tourism, pastoral and mining.

Analysis of information and land sales suitable for the development of a power plant in the Kalgoorlie region show levels for lots of approximately 3 hectares in the range of **$850,000** per hectare (suitable 3 hectares sites outside of the Kalgoorlie townsite show levels in the range of $300,000 per hectare). This has remained unchanged from our 2011 assessment.

COMMENTARY

The Perth and regional Western Australian industrial land markets have remained steady over the past twelve months. The mining boom and continued economic growth for Western Australia has resulted in constant demand for industrial facilities for companies directly involved in mining and those servicing the industry.

In relation to the current land value assessments for the hypothetical sites within the metropolitan and country areas we have made some changes. It should be noted that there has been limited volumes of relevant vacant industrial land sales across the state and these amendments are not necessarily an indication of market trends, rather they reflect our analysis of the current market evidence available.

Overall land values are generally forecast to remain stable, particularly in the outer metropolitan and regional industrial precincts, however it is possible there maybe some growth in land values for the inner industrial areas (including Kwinana) due to increases in demand for limited stocks.

ASSESSMENT

The approach to these assessments has been by the method of direct comparison. The value is derived by comparison to recent sales of properties with typical characteristics for land suitable for the construction of a power plant in the nominated regions.

The assessments provided for the hypothetical sites are on the basis they have no distinct beneficial or detrimental features that would affect the development of a power station or their inherent value as a power station site.

Having regard to the available information and evidence, an estimate of value for each of the proposed hypothetical sites in the nominated regions is considered to be as follows.

REGION	LAND AREA (Hectares)	RATE PER HECTARE	ASSESSED VALUE
Pinjar	3	$1,700,000	**$5,100,000**
Kwinana	3	$2,300,000	**$6,900,000**
Kemerton	5	$250,000	**$1,250,000**
Collie	3	$100,000	**$300,000**
Geraldton	3	$150,000	**$450,000**
Eneabba	3	$40,000	**$120,000**
Kalgoorlie	3	$850,000	**$2,550,000**

ASSUMPTIONS, CONDITIONS, LIMITATIONS

As instructed, this assessment has been completed on the following basis.

- The proposed locations have not been physically inspected.
- The report has been completed using Landgate records and information gathered from external sources only.
- Landgate records relied upon are correct as at the date of this report.
- The assessment amount is exclusive of GST (Goods and Services Tax).
- The assessment amount assumes an unencumbered fee simple title and that any allowance for possible heritage restrictions, native title claims or contamination has not been considered.
- The hypothetical land sites are generic for each region and have no distinct beneficial or detrimental features that would affect the development of a power station or their inherent value as a power station site.
- The hypothetical site for each region can be developed as a power station.
- Our investigations with the relevant Local Authorities revealed no legislative or local planning requirement for setbacks or buffer zones in excess of the standard setbacks outlined within each Local Authorities town planning scheme for the development of a site within existing industrially zoned estates. However town planning officers emphasised that no definitive decision or recommendation could be made without a development application containing detailed plans for a specific lot.

  Having regard to the above we have completed our assessments with the assumption that a 3 hectare site will be sufficient for the development of a power plant.

This assessment has been prepared by Darren Criddle under delegation of the Valuer General as defined in Part II of the *Valuation of Land Act 1978*.

In accordance with the Federal Privacy Act, information supplied is now regarded as private information. Under the Act, information collected for one purpose may only be used for a secondary purpose if that purpose is related and could be reasonably expected. In this context, this Office is not able to give permission for the information to be published by a third party. All data and analysis produced by this Office is provided on the condition that it is the responsibility of the receiver of such information to conform with privacy legislation.

The report is not to be reproduced either wholly or in part, or relied upon by third parties for any use, without the express authority of the Valuer General.

Thank you for your instructions in this matter and if you have any further queries relating to this advice do not hesitate to contact me on 9273 9026.

Yours sincerely

DARREN CRIDDLE - AAPI
CONSULTANT VALUER
PROPERTY & VALUATIONS

VIN LUMBUS - AAPI
MANAGER MARKET VALUES
PROPERTY & VALUATIONS

SINCLAIR KNIGHT MERZ

SKM

imo

INDEPENDENT MARKET OPERATOR

Review of the Maximum Reserve Capacity Price 2013

- WP04558-OSR-RP-0001
- Rev 3
- 24 January 2013

Review of the Maximum Reserve Capacity Price 2013

- WP04558-OSR-RP-0001
- Rev 3
- 24 January 2013

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Contents

Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
A	02/10/2012	Tim Johnson	Tim Johnson	02/10/2012	Project Director Review
0	02/10/2012	Tim Johnson	Tim Johnson	02/10/2012	Issue to IMO
1	16/10/2012	Tim Johnson	Tim Johnson	16/10/2012	Project Director Review pre issue to IMO
2	30/10/2012	Tim Johnson	Tim Johnson	30/10/2012	Update following further comments from IMO
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1. Introduction

As part of the establishment of the Wholesale Electricity Market (WEM) within the South West Interconnected System (SWIS), the Government of Western Australia (WA) set up the Independent Market Operator (IMO) to administer and operate the market.

The Market Rules require the IMO to conduct a review of the Maximum Reserve Capacity Price (MRCP) each year. As part of this process Sinclair Knight Merz (SKM) has been commissioned to determine the following for the year 2013:

- Capital cost (procurement, installation and commissioning, excluding land cost) of a generic single unit, industry standard, liquid fuelled, 160MW open cycle gas turbine (OCGT) power station.
- Fixed operation and maintenance (O&M) costs of the above facility with capacity factor of 2 per cent. The costs shall be in 5 year periods covering 1 to 30 years.
- Fixed O&M costs of the connection assets consisting of a generic 330kV three breaker mesh switchyard configured in a breaker and a half arrangement, that facilitates the connection of a 160MW OCGT power station to an existing transmission line. The costs shall be in 5 year periods covering 1 to 50 years.
- Fixed O&M costs of a 2km, 330kV overhead single circuit steel lattice tower transmission line that connects the power station and the connection switchyard, whereby the switchyard is located in the vicinity of an existing 330kV transmission line. The costs shall be in 5 year periods covering 1 to 60 years.
- Note: insurance expenses are excluded from the above estimates of the fixed O&M costs.
- Fixed fuel costs of the above facility including a 1,000 tonne diesel fuel tank supplying fuel to the power station to enable 14 hours of operation at maximum capacity
- Owner's costs such as legal, approval, environmental and financing costs associated with the term 'M' used in the WEM Rules.

This report should be read in conjunction with the scope of work agreed between the IMO and SKM which explains the approach of this report in detail and is attached in **Appendix C**.

2. Generation plant capital cost

SKM has estimated the capital cost (capex) comprising engineering, procurement, installation and commissioning, excluding land costs of a generic single unit liquid fuel E-class open cycle gas turbine (OCGT) power station with inlet air cooling (where effective) and capable of operating on liquid fuel but excluding liquid fuel storage. The capital cost estimate includes all components and costs associated with a complete gas turbine project consistent with the Scope of Works detailed in **Appendix C**.

2.1. Methodology

SKM has undertaken the following steps to establish the capital costs for a generic single unit 160 MW OCGT plant:

- A Siemens SGT5-2000E with a net nameplate (ISO) rating of 165MW was selected as the reference machine for the study.
- Utilised the 2012 IMO capital cost estimate using Thermoflow GT Pro®/PEACE® for the reference machine with liquid fuel burners, water injection for NO_X emission control, evaporative inlet air cooling. The evaporative air cooling technology was selected as the most effective inlet cooling technology based on previous analysis undertaken for the IMO[1] and is consistent with SKM's understanding of the technologies commonly adopted for installations in the South West of Western Australia.
- Updated the reference plant model to include 2012 pricing for the main plant equipment.
- Escalated the cost of the remaining items using various historic (year end to June 2012) escalation indices appropriately composed to each make-up component of the total capex to provide an estimate in June 2012 dollar terms.
- Benchmarked the plant capital costs ($/kW basis) against a recently completed project in WA
- Provide the likely net maximum output for the reference machine at 41°C with evaporative cooling, likely humidity conditions and any other relevant factors using GT Pro®/PEACE®.

The SKM study is based on liquid fuel (distillate) being supplied and stored, fully in accordance with the gas turbine manufacturer's specification requirements, and used as the sole fuel source for the operation of the plant. Other potential liquid fuels or the provision of fuel treatment or conditioning facilities have not been considered in the development of any capital or operating cost estimates presented in this study. Note that the cost of the infrastructure to achieve the above is given in **Section 5** – Fixed fuel costs.

In developing the matrix of costs, SKM has utilised:

[1] Analysis can be found at http://www.imowa.com.au/f2179,1630289/WP04268-RPT-ME-001-A_1_Capacity_Augmentation_on_MRCP_Rev1.pdf

- Knowledge and experience of generation project development.
- Database for power station capital and operating costs.
- Knowledge of the impact of the flow through of commodity price increases, labour costs, etc., on generation station capital costs and hence appropriate escalation indices.
- Knowledge and experience in generation project costing, including typical allowances for owner's costs.

In developing the cost estimates, SKM has assumed a standard green field site located in Western Power's SWIS region having no special geological, environmental, permitting or consenting peculiarities. In particular it has been assumed that there are no unusual requirements for ground preparation, such as piling or land remediation.

The project costs are substantially based on historical project information and the output of the project data price review.

2.2. Project data price review

In developing the end cost estimate, SKM utilised reference project data developed for the 2012 IMO report. The reference project consists of Thermoflow GT Pro® heat balance model and corresponding PEACE® cost estimate. The model utilised information (i.e. total-man hours, labour rates, and equipment costs) garnered from a number of OCGT projects and studies that had been completed in Australia from 2007-2010.

The reference project cost model was updated to reflect to current (2012) pricing for main plant equipment. The remaining project capital costs components were escalated using various historic (year end to June 2012) escalation indices appropriate to each make-up component of the total capex to provide an estimate in June 2012 dollar terms.

2.3. Development of the generic OCGT capital cost estimate

The capital cost estimates is based on a single dual fuel (natural gas and distillate fuel oil) generating unit. The capital costs exclude the distillate fuel storage and unloading systems, that are determined separately in Section 5. Demineralised water treatment plant, a 1,200 tonne demineralised water storage tank (equivalent to 1,000 tonne of distillate use at a water-to-fuel mass ratio of 1.2:1), and storage for 240 tonne of potable water storage plus 1 hour of fire control are included in the capital costs.

The cost estimate has been based on dual fuel (natural gas and distillate) operation for gas turbines fitted with dry low emissions (DLE) combustion technology. NO_X emissions would typically be in the range of 25ppmv dry at 15% O_2 reference conditions when firing natural gas and 42ppmv dry at 15% O_2 when operating on distillate fuel oil with water injection. The generic cost estimates assume that water injection for NO_X emissions abatement will be required for liquid fuel operation and that on site water treatment and storage facilities will be included. Low NO_X burners are included in the capital cost estimate.

In addressing any need for water injection requirements, the potential source of the water, the treatment and conditioning of the water to achieve the demineralised quality required for any water injection systems, the on-site storage capacity requirements of such water and the disposal and treatment of effluent from any treatment system have been taken into consideration. However, these assumptions are based on sufficient[2] potable or similar quality water supplies being available local to the facility either through pipe or tanker delivery. The requirements for extensive or complex water abstraction or treatment facilities have not been considered.

2.4. OCGT capital cost estimate

A breakdown of the capital cost estimate for a 160 MW generic single OCGT plant is given in Table 2-1 below. The estimate represents a generic cost for an OCGT plant constructed on an EPC basis. Owner's costs additional to the EPC contract price have been excluded, and are accounted for in the calculation of the term "M" in **Section** 7.

The total capital cost estimate was calculated as **A$121,748,821** which equates to **A$763/kW**[3].

Table 2-1 Generic 160 MW OCGT capital cost estimate

Item	Cost [$]
Main Plant Equipment	64,234,348
Balance of Plant	3,166,176
Civil Works	13,572,453
Mechanical Works (including installation)	13,125,062
Electrical Works (including installation)	2,713,135
Buildings	2,471,411
Engineering & Plant Start-up	3,687,638
Contractor's Costs	18,778,598
Total EPC Cost	121,748,821

All costs are presented as mean values and are in June 2012 dollars. The reference price for main plant equipment is based upon EUR/AUD exchange rate of 0.811.

SKM notes that the total cost estimate has reduced by approximately **A$4.6million** dollars from that estimated in the "2012 Review of the Maximum Reserve Capacity Price" report.

The majority of the main plant equipment for the OCGT plant project is manufactured overseas in Europe, thus the exchange rate movements between 2011 and 2012 have a significant impact on the total estimated capital cost. The weakening Euro or conversely the relative strength of the

[2] Sufficient quality is defined as potable water capable of operating in the evaporative cooler at 2-3 cycles of concentration.
[3] Based on 159.6 MW net output defined in section 2.5.

Australian dollar results in a reference price decrease of approximately 10% for the SGT5-200E gas turbine plant.

This decrease in balance of plant, mechanical and electrical works was impacted by combination of the falling prices of copper and steel and the weakened Euro and American dollar relative to the Australian dollar.

The increase in local costs is reflective of the continuing tight market for construction labour and plant in Western Australia.

2.5. Likely output at required conditions

The output of the reference OCGT, with evaporative type combustion air inlet cooling and water injection for emissions abatement purposes, at 41°C, 30% relative humidity and typical atmospheric air pressure conditions is detailed in the table below.

- **Table 2-2 Generic 160 MW OCGT parameters**

Parameter	Units	Value
GT Model		Siemens SGT5-2000E
Configuration		Open cycle
Fuel		Distillate
Evaporative inlet air cooling effectiveness	[%]	85
Water injection ratio	[M_w/M_f]	1.2
Site altitude	[m]	25
Temperature	[^oC]	41
Relative Humidity	[%]	30
Gross output	[MW]	162.0
Net output	[MW]	159.6

3. Generation fixed operation & maintenance costs

3.1. Assumptions and exclusions

An OCGT plant based on a single gas turbine capable of delivering a nominal 160MW output operating on distillate fuel oil has been evaluated for a 30 year operating life.

SKM has developed an estimate for fixed O&M costs for the peaking power plant based on a 2% capacity factor, expected to operate infrequently solely on distillate fuel oil. Gas connection costs are therefore not considered in this estimate. Connection switchyard and overhead transmission line fixed O&M are covered separately in Section 4 of the report.

In accordance with the September 2009 report[4] for the IMO, prepared by MMA in conjunction with SKM, the cost of scheduled maintenance overhauls based on number of starts and number of operating hours has been considered as a variable O&M cost, and is not included in this estimate. An allowance for regular balance of plant upkeep and maintenance has been included.

A generation utility owner's annual revenue entitlements will include a component for the depreciation of their assets. Depreciation relates to capital costs, distributing the loss in value of the assets over the lifetime of the plant. It is not a part of the ongoing costs to operate and maintain the assets, and as such it has not been considered in this estimate or in previous estimates.

3.2. Generation operation & maintenance costs

The fixed O&M cost elements shown below in Table 3-1 have been developed from cost data derived from a range of sources including an amalgam of data from current and recent similar OCGT projects. The addition of evaporative inlet air cooling and associated raw water storage has negligible impact on the fixed balance of plant maintenance costs.

- **Table 3-1 OCGT plant fixed O&M costs**

O&M Cost Component	[$M pa]
Plant operator labour	0.538
OCGT substation (connection to tie line)	0.247
Rates	0.060
Market fee	0.060
Balance of plant	0.131
Consent (EPA annual charges emissions tests)	0.032

[4] *MMA September 2009, 'Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2009', Available on the IMO website.*

O&M Cost Component	[$M pa]
Legal	0.027
Corporate overhead	0.227
Travel	0.026
Subcontractors	0.354
Engineering support	0.071
Security	0.130
Electrical (Including control & instrumentation)	0.128
Fire	0.062
Total	**2.093**

These costs have been escalated, where appropriate, to June 2012 dollar terms. The costs for statutory reporting requirements, for which are common requirements to all generating plants, are inclusive of the costs allocated to the corporate overhead and subcontractor components.

Five yearly aggregate fixed OCGT O&M costs are provided in Table 3-2 for each five year period of the 30 year operating life.

- **Table 3-2 Fixed OCGT plant O&M costs (June 2012 dollars)**

Five Yearly Intervals	1 to 5	6 to 10	11 to 15	16-20	21-25	26-30	1 to 30
Fixed O&M Costs (A$)	$10,463,467	$10,463,467	$10,463,467	$10,463,467	$10,463,467	$10,463,467	$62,780,803

All costs are presented as mean values.

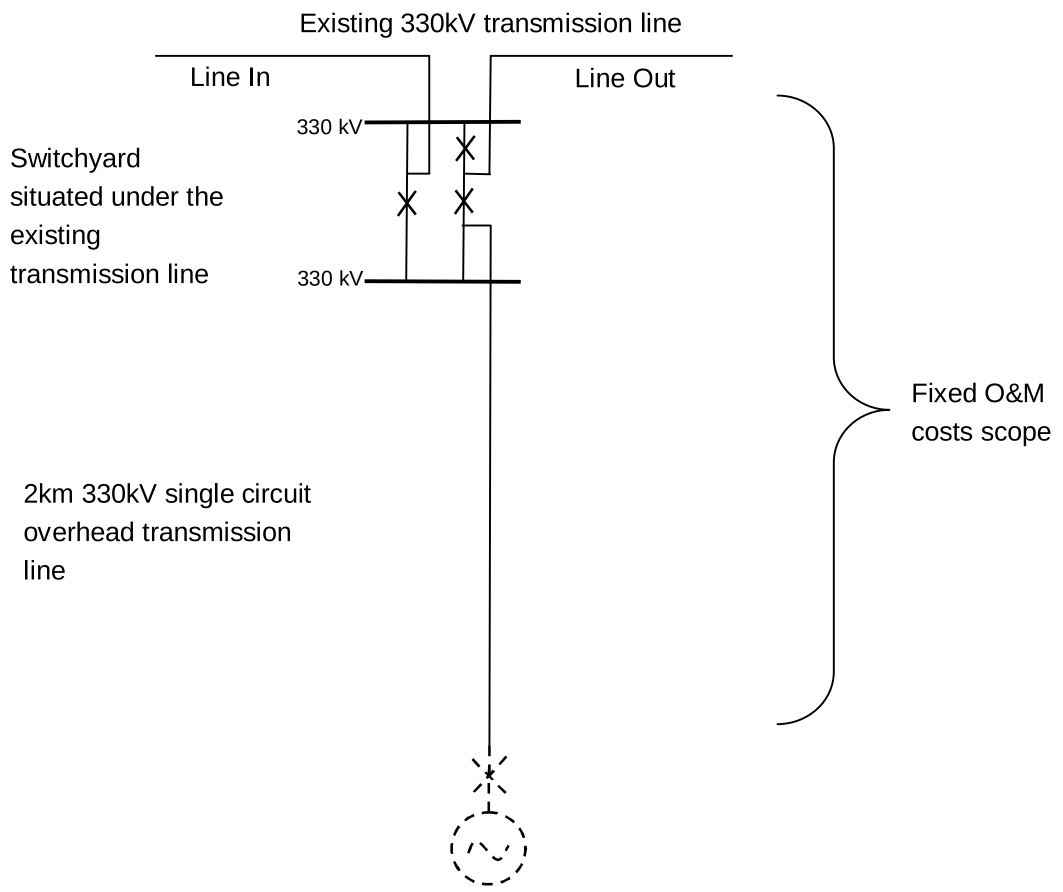
4. Connection switchyard and overhead transmission line fixed operation and maintenance costs

4.1. General

The connection switchyard fixed O&M costs have been based on the arrangement shown in Figure 4-1.

The fixed O&M costs for this section have been calculated from the isolator on the high voltage side of the generator transformer and therefore do not include any of the costs associated with the generator transformer and switchgear.

- **Figure 4-1 Overall connection arrangement.**



The new transmission line is assumed to be a single circuit 330kV construction with 2 conductors per phase. The rating of the line has been selected to facilitate the transport of up to 200MVA (at a power factor of 0.8, a 160MW OCGT can export up to 200MVA).

4.2. General issues and assumptions

SKM has developed the fixed operation and maintenance costs for the network connection on an asset class basis. Therefore a bottom-up approach has been used to estimate the fixed O&M cost of switchyard and transmission line assets based on recent data from several Australian transmission network service providers (TNSPs). It is noted that these O&M estimates are based on the assumption that the assets represent an incremental addition to a large asset base.

Maintenance cost for an asset is incurred periodically according to its maintenance routines. Since this routine is different for different asset classes, SKM has smoothed these periodic costs evenly over the life of the switchyard and transmission line. The annualised fixed O&M cost estimate allows for the following:

- Cost of labour for routine maintenance.
- Cost of machine/miscellaneous items for routine maintenance.
- Overheads (management, administration, operation etc).

The annualised fixed O&M cost estimates for the switchyard and the transmission line are reported in Section 4.3 and Section 4.4 respectively.

The annualised fixed O&M cost does not allow for defect or asset replacement during the lifetime of the assets. It should be noted that annual insurance costs and tax have been omitted from the annualised fixed O&M costs as these cost components will be dependent on the ownership arrangement and beyond the scope agreed between IMO and SKM.

Depreciation is a separate individual component that forms a part of a regulated utility's annual revenue entitlement. Unlike O&M costs, depreciation relates to the capital cost of the assets. It is an accounting method that allocates the capital cost of the assets over the series of accounting periods to gradually write-off the value of the installed assets from the accounting book. Depreciation is not a part of an asset's ongoing cost to maintain and operate it and thus is different from O&M costs. Therefore, it is not included in the fixed O&M costs estimation.

4.3. Switchyard annualised fixed operational & maintenance costs

SKM has assumed that the average life of the 330kV switchyard assets is 50 years. Table 4-1 shows the cumulative annualised fixed O&M costs presented in 5 yearly periods over the lifetime of the switchyard assets. The annualised fixed O&M cost over the asset lifetime for the switchyard is $58,000 pa in June 2012 dollar terms.

- **Table 4-1 Annualised fixed O&M costs for switchyard assets.**

Period	Cumulative Annualised Fixed Switchyard O&M Costs (in 2012 A$)
1 to 5 years	$290,000
6 to 10 years	$290,000
11 to 15 years	$290,000
16 to 20 years	$290,000
21 to 25 years	$290,000
26 to 30 years	$290,000
31 to 35 years	$290,000
36 to 40 years	$290,000
41 to 45 years	$290,000
46 to 50 years	$290,000

4.4. Transmission line annualised fixed operational & maintenance costs

SKM has assumed that the average life of the 330kV transmission line is 60 years. Table 4-2 shows the cumulative annualised fixed operation and maintenance costs presented in 5 yearly periods over the lifetime of the transmission line assets. The annualised fixed O&M cost over the asset lifetime for the transmission line is $1,130 pa in June 2012 dollar terms.

- **Table 4-2 Annualised fixed O&M costs for transmission line assets**

Period	Cumulative Annualised Fixed Transmission Line O&M Costs (in 2012 A$)
1 to 5 years	$5,650
6 to 10 years	$5,650
11 to 15 years	$5,650
16 to 20 years	$5,650
21 to 25 years	$5,650
26 to 30 years	$5,650
31 to 35 years	$5,650
36 to 40 years	$5,650
41 to 45 years	$5,650
46 to 50 years	$5,650
51 to 55 years	$5,650
56 to 60 years	$5,650

5. Fixed fuel costs

5.1. Introduction

The estimation of the capacity price for 2013 is to include, as per previous years, costs associated with the fuel supply. The cost is denoted as the Fixed Fuel Cost (FFC) in the Market Procedure.

This component is the cost associated with the development and construction of an onsite liquid fuel oil storage and supply facilities, with supporting infrastructure, with sufficient capacity for 24 hours of operation on liquid fuel, including the cost of initially filling the tank with fuel to a level sufficient for 14 hours operation.

5.2. Fixed fuel cost scope

5.2.1. IMO defined requirements

The IMO defined Fixed Fuel Costs for the liquid fuel storage and handling facilities are to include:

a. A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund suitable for 14 hours operation.

b. Facilities to receive fuel from road tankers.

c. All associated pipework, pumping and control equipment.

5.2.2. Included scope

The scope of work, for the supply of diesel fuel oil included as the basis of the estimation of the Fixed Fuel Cost component, comprises:

i. Road tanker fuel oil unloading facilities, including:
   a. 2 x fuel road tanker oil unloading station arms, interconnecting header piping and valves.
   b. 2 x motor driven fuel unloading pumps complete with inlet suction strainers, interconnecting piping and valves.
   c. Fuel oil delivery metering equipment.
   d. Interconnecting piping, valves and fittings from the unloading station to the fuel oil storage area.
ii. Bulk fuel oil storage facilities, including:
   a. 1 x bulk diesel fuel oil storage tank, complete with all necessary fittings.
   b. 1 x waste oil collection tank, complete with all necessary fittings.
iii. Fuel forwarding and supply facilities, including:
   a. 2 x duty and standby motor driven fuel oil forwarding pumps, complete with inlet suction strainers, interconnecting piping and valves.
   b. 2 x duty and standby filter separator trains.
   c. 1 x fuel supply metering equipment.

d. Interconnecting piping, valves and fittings from the fuel tank to the forwarding pumps and from the forwarding pumps to the open cycle gas turbine (OCGT) fuel oil connection, with recirculation return to storage.

iv. Oily water treatment and separation equipment, including:
   a. 2 x motor driven waste water collection and supply pumps complete with inlet suction strainers, interconnecting piping and valves.
   b. Oily water separator, above ground plate type separator or similar.
   c. Interconnecting oily waste water, waste oil piping and treated water interconnecting piping, valves and fittings.

v. Electrical equipment and supporting systems for the above equipment, including interconnecting cabling and fittings.

vi. Local plant mounted instrumentation, control and protection systems for the above equipment, including interconnecting cabling and fittings

vii. Civil and structural works, including:
   a. Fuel oil road tanker unloading and oil spill containment area.
   b. Bulk fuel oil storage tank foundations and concrete containment bund area.
   c. Fuel unloading and forwarding pump area foundations and spill containment area.
   d. Weather protection canopies or similar structures.
   e. Miscellaneous equipment and piping supports and structures.

The assumed main limits of supply and terminal interface connection points include:

i. Fuel oil delivery road tanker vehicle unloading / loading connections.
ii. Waste oil collection tanker vehicle loading connections.
iii. Fuel oil supply connection to the OCGT at a single connection point.
iv. Fuel oil return connection from the OCGT at a single connection point.
v. Treated water discharge connection to the site drainage system at a single point local to the fixed fuel oil facility perimeter boundary.
vi. AC power supply connection at the fixed fuel oil facility distribution board equipment.
vii. Earthing connections to the power station earth grid local to the fixed fuel oil facility perimeter boundary.
viii. Control and communications connections at a marshalling panel provided within the fixed fuel oil facility.

5.3. Basis of design

5.3.1. Process design, assumptions and qualifications

The concept design and associated cost estimate for the fixed fuel oil storage and supply facilities are based on the following concept design, assumptions and qualifications:

i. The fixed fuel oil facilities are to be designed to unload, store and supply standard automotive diesel fuel oil, fully suitable for use and service in a gas turbine power station facility, in accordance with the OCGT manufacturer's recommendations and requirements.

ii. The fixed fuel oil facility provisions exclude any fuel systems directly associated with the OCGT package systems, including high pressure fuel oil supply and metering pumps; fuel oil conditioning and regulation equipment; OCGT fuel metering equipment; fuel line flushing or similar equipment; combustion equipment; etc.

iii. The fixed fuel oil unloading, storage and supply facilities will form an integral element of the overall OCGT power station installation. They will be located directly adjacent and within the boundaries of the overall power station and as such it is assumed they will be developed and constructed at the same time as the power station.

iv. In accordance with the above, it has been assumed that all environmental and similar consents and approvals, for the fixed fuel oil facility, will be covered within the overall power station approvals processes.

v. It is assumed that the area for the fixed fuel oil facility will be cleared and generally graded to a level profile, as part of the main power station development site works. No bulk earthworks or similar provisions have been included within the fixed fuel oil estimated requirements.

vi. It is assumed that the fixed fuel oil facility and the power station site elevations are approximately the same, with no substantial benching between the respective facilities.

vii. As with the main power station, it is assumed that the fixed fuel oil facility site is suitable for the intended purpose and has no special or unusual geological features, requiring removal of contamination or similar remediation; removal of underground obstructions; rock excavation; piling or similar structural improvement works.

viii. It is assumed that site access and access roads to the fixed fuel oil facility will be shared with the main power station. Separate stand alone road tanker or maintenance vehicle access roads; vehicle turning or general parking areas (other than the main road tanker unloading bay); access gates; or similar facilities, have not been considered or included in the fixed fuel oil facility installation.

ix. Similarly, it is assumed that security and isolation fencing for the fixed fuel oil facility will form part of the overall power station boundary fencing provisions.

x. It is assumed that access control, CCTV or similar surveillance and security facilities will be covered as part of any overall power station provisions and are not separately covered within the fixed fuel cost.

xi. It is assumed that the fixed fuel oil equipment will be suitable for outdoor installation. The main fuel oil storage containment and road tanker unloading areas will not be covered. The fuel oil pumping and electrical equipment areas will be provided with local open sided weather protection canopies.

xii. No fuel oil heating or similar conditioning has been considered or included within the fixed fuel oil facility requirements. Any heating or similar requirements for fuel viscosity regulation at inlet to the OCGT are assumed to be provided (if required) within the power station scope.

xiii. It has been assumed that insulation and cladding of the fixed fuel oil facility equipment is not required.

xiv. Similarly, it has been assumed that fuel will be delivered to the facility in a suitable quality and condition in accordance with Australian standards. Other than standard filtration and the draw off and separation of free water, no additional fuel oil treatment or conditioning has been considered or included.

xv. It is assumed that power station fire water supply facilities (e.g. the fire water storage and pumping capacity), will be sufficiently rated to meet the hazard requirements of the fixed fuel oil facility. The installation of separate or dedicated fire water storage and pumping capacity, serving the fixed fuel oil storage facility had not been considered or included. It is assumed that the power station fire main and hydrant system will be extended to include hydrant outlet points (not less than 2 separate individual pillar hydrants) local to the fixed fuel oil facility. Fixed tank shell water spray manifolds or internal tank fire foam dispensers, within the bulk storage tank facilities, have not been considered or included.

xvi. Fuel will be delivered to the fixed fuel oil facility in standard road tanker vehicles. The fuel oil unloading facility will consist of a fuel oil unloading bay sized to accommodate a maximum road tanker overall vehicle length of 36.5m. The assumed road tanker unloading bay will be sized to accommodate and unload 1 x single tanker at a time. A maximum unloading bay width of 6.0m has been assumed. Twin unloading connection points to simultaneously unload two road tanker vehicle storage cylinders will be provided.

xvii. Fuel oil will be transferred from the road tankers by the unloading pumps. Twin unloading pumps will be manifolded together and will be capable of operating in parallel, to discharge and transfer the full contents of the tanker to the bulk storage facility within 1 hour. The fuel oil unloaded will be metered.

xviii. A single bulk fuel oil storage tank has been considered, in accordance with previous reports.

xix. Fuel oil from the storage tank shall be delivered to the forwarding pump suction for supply to the OCGT. Duty and standby forwarding pumps will be provided, with suitable filtration and separation equipment provided for each stream.

xx. It has been assumed that the maximum overall route length of fuel oil supply piping from the forwarding pumps to the OCGT inlet connection will be 100m.

xxi. In typical OCGT applications a fuel oil return line from the OCGT to fuel oil storage facility is required. A fuel oil return line of up to 100m overall route length has been included.

xxii. The fixed fuel oil unloading, storage and fuel oil pumping areas will be within containment bund areas. It is assumed that all containment bunds including the road tanker unloading bay will be concrete construction, with suitable low permeability construction joint seals. It is assumed that concrete surfaces will not be provided with additional coatings. Containment bunds will be designed in accordance with AS 1940 requirements.

xxiii. It has been assumed that all piping will be located above ground, on low level pipe supports, wherever practicable. Other than the main supply to / from the OCGT, fuel oil piping will be located predominantly within the fuel oil equipment spillage containment areas. As such dual wall or 'pipe in pipe' fuel oil piping construction has not been considered or included.

xxiv. A waste oil collection tank will be located within the main fuel oil storage containment bund. Waste oil sludge and emulsions form the main fuel oil storage tank will be periodically drained to the waste oil collection tank. Waste oil pumps and piping will be provided to discharge the waste oil to a waste oil tanker vehicle, for disposal.

xxv. All rainwater collected within oil containment bund area drainage sumps. Sump pumps will discharge collected and potentially contaminated to a plate type oily water separator. The oily water separator will be located within the main fuel oil storage tank containment area. Separated oil will be discharged from oily water separator to a waste oil collection tank. Treated water from the oily water separator will be discharged to the power station drains system at the fixed fuel oil facility perimeter boundary.

xxvi. Waste oils, free oils and emulsions will not be discharged into any stream which directly feeds the oily water separator.

xxvii. A fuel oil facility switch board and motor control centre will be provided for location within the fixed fuel oil facility, local to the fuel equipment. Interconnecting cabling and fittings from the switchboard and motor control centre to each of the fixed fuel oil facility power consumers has been included. It has been assumed that a power supply, including cabling and fittings, from the power station to the fixed fuel oil supply switchboard incomer is included in the power station scope.

xxviii. Earthing and lightning protection provisions are included for the fixed fuel oil facility. It is assumed that the fixed fuel oil facility earth grid will be connected to the main power station earth grid.

xxix. Local instrumentation, including level, pressure, temperature and flow is provided. Interconnecting control and monitoring cabling and fittings, between plate mounted instrumentation and a local marshalling panel will be provided, as appropriate. Key parameters, and signals, specifically level and flow indication and alarms will be made available at a marshalling panel for connection to the power station control and monitoring systems. Control and monitoring cabling between the power station and the fixed fuel oil facility is excluded.

xxx. The fixed fuel oil facility cost estimate will separately include provisions for the initial fuel oil fill quantities, based on 14 hours operation at nominally 160 MW capacity and fuel cost per litre as reported by the IMO in the “2012 Review of the Energy Price Limits for the Wholesale Electricity Market in the SWIS (dated June 2012).

xxxi. No contingency factor has been applied to the determined fixed fuel cost.

5.3.2. Codes and standards

The bulk fuel oil storage facility will be designed in accordance with the requirements of AS 1940 “Storage and Handling of Flammable and Combustible Liquids”.

It is assumed that the bulk fuel oil diesel fuel oil storage tank will be designed and constructed in accordance with the American Petroleum Institute (API) 650 requirements, or similar alternative acceptable standard.

Piping systems will be designed in accordance with the requirements of AS 4041 "Pressure Piping".

5.3.3. Fuel oil characteristics

The fuel to be stored and supplied to the OCGT is automotive diesel fuel oil, classified as a "combustible liquid", Class C1". It is assumed that "Ultra Low Sulphur" specification fuel oil, in accordance with Western Australian fuel supply requirements, will be provided.

The physical and heating values properties of diesel fuel vary, within specified limits, depending on fuel grade and source. For this report it is assumed that the fuel oil higher heating value (HHV) will be 46 MJ/kg and the corresponding specific gravity will be 0.84.

5.3.4. Bulk fuel storage capacity

The required overall fuel oil storage working capacity is 1000 tonnes, this is estimated as able to provide 24 hours of operation at 160 MW of generation.

Based on a specific gravity of 0.84 the minimum required working bulk fuel oil storage tank working capacity must be not less than 1200m^3. The estimated minimum tank gross capacity, assuming a 10% allowance provision for minimum working fluid level above the tank bottom and fluid thermal expansion, will being region of 1310m^3.

5.3.5. Bulk fuel oil storage tank

The bulk fuel oil storage tank is considered to be a site erected vertical cylindrical type, above ground tank, with a fixed roof.

The currently estimated tank dimensions are 14.2m diameter x approximately 9.0m high.

The material of construction is carbon steel. The tank external surface will be protected and painted with an epoxy or similar coating paint system. The tank internal surfaces will be typically protected only with holding delivery / construction primer, with no further protection. The tank roof and shell areas, above the maximum fuel oil level, will be suitably coated.

It is assumed that a floating suction will be provided for the main fuel oil outlet connection. Additional tank process accessories include fuel oil inlet and return connections; vent, drain and waste draw off nozzle connections; and level and temperature instrumentation connections.

The tank floor will be graded to fall to an inverted sludge collection sump. Waste oil piping from the collection sump to the tank shell will be provided.

The tank will be provided with shell and roof access manways. The tank roof perimeter will be provided with handrails, local to the access manway, with an access stairway provided to roof level.

It is assumed that a conventional tank concrete ring beam foundation, with a compacted sand / bitumen mix infill, will be provided.

5.3.6. Bulk fuel oil storage containment bunds

The bulk fuel oil storage tank will be located within a containment bund, consisting of a concrete ground slab and concrete bund walls.

The containment bund will be sized in accordance with AS 1940 requirements, to contain and prevent overtopping of the bund, including the maximum fuel oil storage volume; plus an allowance for fire water spay volume; plus the potential for residual rainwater collection in the bund.

Based on these requirements and assuming a 10 year ARI event, then it is assumed that the overall bund dimensions will be in the region of 32m x 32m x 1.6m high.

5.3.7. Road tanker unloading area

The fuel tanker vehicle unloading bay will be concrete slab construction, with sloped edge containment beams and entry and exit trafficable containment “humps”, suitably graded and drained to a containment drainage sump. The fuel tanker area containment volume will be sized for the maximum volume of a single vehicle tanker failure, with an additional allowance for fire water and similar provisions to prevent overtopping.

5.3.8. Fuel oil pump equipment area

The fuel oil unloading stations, unloading pumps, forwarding pumps and associated fuel oil conditioning equipment will be located in fuel oil area equipment area, located directly adjacent to the road tanker unloading bay and the main fuel oil tank containment bund. The fuel oil equipment area will be bunded, to contain any spillages, which will be drained to a containment drainage sump.

It is intended that a weather protection canopy be provided over the fuel oil pump equipment area.

The electrical switchboard equipment and associated control and monitoring equipment will be located adjacent to the fuel oil pump equipment.

5.3.9. Oil and water waste facilities

Waste oil sludge and oil emulsion from the main fuel oil storage will be drained to a waste oil collection facility. Similarly fuel oil pump and fuel oil filter body equipment oil drains will be contained and discharged to the waste oil collection tank. A 10m^3 packaged horizontal, cylindrical waste oil collection tank is included. The waste oil tank will be located within the main fuel oil storage tank containment bund. Oil drain pumps will be provided to discharge the waste oil to a waste collection tanker vehicle.

Oily water, from all fuel oil containment bund drain collection sumps, will be pumped (using progressive cavity or similar type pumps) and delivered to an oily water separator unit. The oily water separator unit will be a standard plate type separator suitably rated to enable treatment of not less than $20m^3/h$ of oily waste water.

Free oil or oil emulsions will not be passed through the oily water separator, but will be separately collected and drained to the waste oil collection tank. Separated oil from the oily water separator will be discharged to the waste oil collection tank.

Separated treated water from the oily water separator unit will be discharged to the power station site drains, local to the fixed fuel oil facility.

5.4. Estimated cost

5.4.1. Estimate classification

SKM has generally adopted the AACE (Association for the Advancement of Cost Engineering) international recommended practices for the classification of capital cost estimates (CAPEX), in accordance with the table in Appendix B. Based on the current level of information and the level of completed engineering and definition, the presented Fixed Fuel Cost estimate is a Class 4 Order of Magnitude Estimate.

This classification is directly comparable with the Type 1 estimate basis, used and reported in previous years.

5.4.2. Basis of the estimate

The basis of the capital cost estimate is in accordance with the criteria outlined in the table and includes the following information sources:

- Factoring of a June 2012 budget quotation, for a comparable project, based on the supply, installation and testing of fuel oil storage tanks of the same capacity.
- Materials take-offs of the preliminary civil and structural design completed for this facility, to which composite material rates were applied.
- Similarly, application of composite estimated installed rates for estimated piping quantities and similar commodities.
- Application of factors for the remaining scope of works as described in the table.

The estimated capital cost outcome is detailed in the following sections.

5.4.3. Fuel facilities costs

The estimated capital cost for the fixed fuel oil facility as presented in this report is **A$ 5.81 million**.

The estimate is an Order of Magnitude Class 4 type estimate.

5.4.4. Cost of fuel

The estimated cost of diesel fuel is A$ 23.62/GJ (higher heating value), based on the IMO "2012 Review of the Energy Price Limits for the Wholesale Electricity Market in the SWIS (dated June 2012)" report. This cost includes delivery transportation but excludes excise and GST.

This corresponds to A$ 1.0865/kg based on a higher heating value of 46 MJ/kg; or A$ 0.9127/litre based on a specific gravity of 0.84.

To maintain consistency with previous years' reports, the first fill fuel oil quantity, based on 14 hours operation and an allowance for maintaining a minimum tank working volume, is 815m^3.

The estimated cost of first fill capacity as presented in this report is **A$ 0.74 million**.

5.4.5. Estimate summary

The estimated capital cost breakdown is summarised as follows:

- **Table 5-1 Estimate Summary**

No.	Item description	A$ k
1	Main Plant Equipment, including installation: ▪ Main fuel oil storage Tank	$ 1,491.0
2	Mechanical Balance of Plant (BoP) equipment, including installation: ▪ Fuel oil pump equipment. ▪ Oily water separator equipment. ▪ Piping and fittings	$ 707.2
3	Civil and Structural Works, including installation	$1,899.2
4	Electrical and Control Works, including installation	$ 426.6
5	Spares and consumables	$ 67.3
6	Engineering, procurement and construction management (12%)	$ 542.9
7	Contractor's On-costs, including risk, insurance and profit	$ 678.6
A	**Total - Fixed Fuel Oil Facility CAPEX**	**$ 5,812.8**
B	**Base fuel storage of 815 m^3 @ A$ 0.9127/l**	**$ 743.8**
	TOTAL	**$ 6,556.6**

6. Cost escalation forecast

6.1. Background

SKM has been actively researching the cost of capital infrastructure works, particularly in the electricity industry, for a number of years, and has developed a cost escalation modelling process which captures the impact of forecast movements of specific input cost drivers on future electricity infrastructure pricing, providing robust cost escalation rates.

SKM's capex cost escalation model has been used extensively in developing cost escalation indices for a number of transmission and distribution network service providers throughout Australia. The SKM cost escalation methodology has also been accepted by the AER in revenue proposals submitted by these utilities.

The model draws upon strategic procurement studies that SKM conducted in 2006 and 2010 which surveyed the equipment capital costs of a broad range of NSPs throughout Australia. Procurement specialists and equipment suppliers/manufactures were also brought into the process to ascertain the weighting of underlying cost drivers that influenced the final cost of each plant and equipment item. These cost drivers were identified through the projects undertaken by the utilities.

Historical and forecast movements of these underlying cost drivers are periodically obtained from various sources and are used to populate the model. This information is typically sourced from well recognised public domains as well as being acquired from professional subscription services. The escalation factors developed for the IMO were based on the most up-to-date information available at the time of compilation.

6.2. Limitation statement

Forecasts are by nature uncertain. SKM has prepared these projections as an indication of one possible outcome it considers likely in a range of possible outcomes. SKM does not warrant or represent the selected outcome to be more likely than other possible outcomes and does not warrant or represent the forecasts to be more accurate than other forecasts. These forecasts represent the authors' opinion regarding the outcomes considered possible at the time of production, and are subject to change without notice.

SKM has used a number of publicly available sources, other forecasts it believes to be credible, and its own judgement and estimates as the basis for developing the cost escalators contained in this report. The actual outcomes will depend on complex interactions of policy, technology, international markets, and multiple suppliers and end users, all subject to uncertainty.

6.3. Individual escalation driver forecasts

6.3.1. General

Table 6-1 presents the forecasted nominal end of June escalation rates for each driver over the next 5 years.

- **Table 6-1 Individual nominal escalation rate forecast year to June for next 5 years**

	CPI	EGW Labour	WA Labour	Copper	Steel	Construct
2013 Nominal	3.00%	4.32%	4.29%	-7.73%	-0.01%	3.10%
2014 Nominal	2.50%	4.32%	4.29%	4.18%	6.55%	2.75%
2015 Nominal	2.50%	4.32%	4.29%	3.31%	2.41%	2.49%
2016 Nominal	2.50%	4.32%	4.29%	2.43%	0.71%	2.61%
2017 Nominal	2.50%	4.32%	4.29%	0.29%	2.76%	2.59%

Commentary on the methodology for developing each of the individual driver escalation rates are in the following sections.

6.3.2. CPI

SKM applies a method of forecasting the position of CPI as accepted by the Australian Energy Regulator (AER) in several recent Final Decisions for distribution utilities, including the NSW, Queensland and Victorian distribution businesses.

This method adopts the following process:

- Use two years of forecasts from the most recent Reserve Bank of Australia (RBA) Monetary Policy Statement – (the August 2012 Monetary Policy Statement, Economic Outlook, Inflation, Table 6.1 forecasts were used).
- Thereafter extrapolate CPI as the RBA and the Treasury inflation target's midpoint of 2.50 per cent.

The CPI figures used in SKM forecast modeling are presented in Table 6-2

- **Table 6-2 Year to June CPI forecast**

Year to June	2012	2013	2014	2015	2016	2017
CPI Forecast	1.18%	3.00%	2.50%	2.50%	2.50%	2.50%

6.3.3. EGW labour

This labour price index captures the labour cost escalation for electricity, gas, water and waste water (EGW) or 'Utilities' sector. As this workforce has been in high demand and seen greater than average wage increments in recent times, SKM deemed it necessary to separate these costs from general labour.

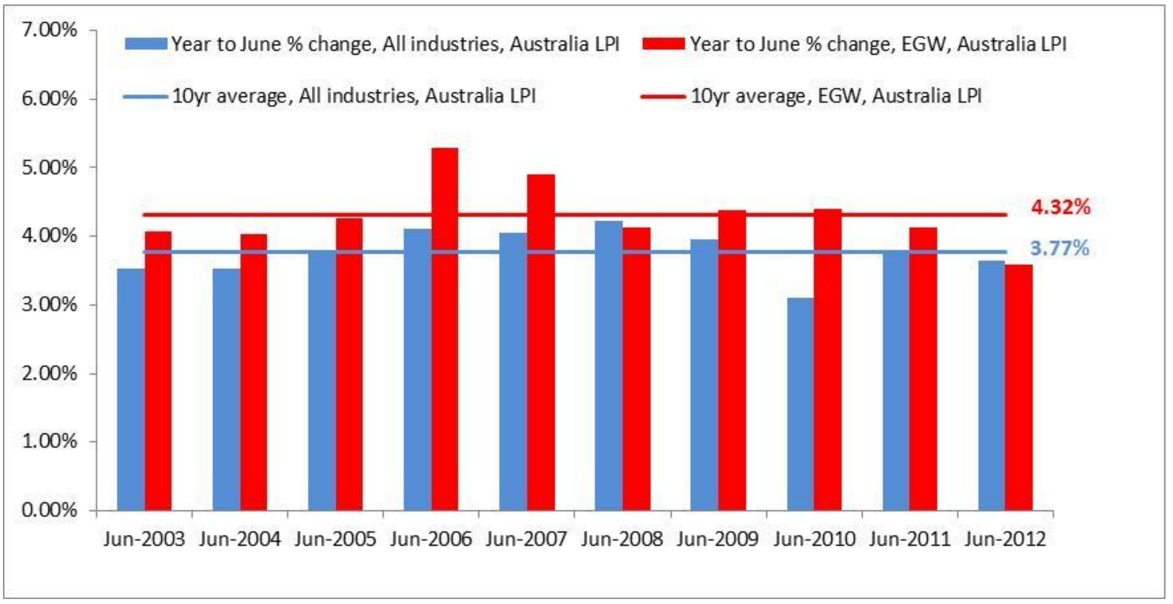
SKM used the data published by the Australian Bureau of Statistics (ABS) to develop this cost escalation component. The ABS 6345.0 Labour Price Index; Table 2a to 9a All WPI series: original (financial year index numbers for year ended June quarter); financial year index; total hourly rates of pay excluding bonuses; Australia; private and public; electricity, gas, water and waste services; Series ID A2705170J was used for this purpose.

Table 6-3 and Figure 6-1 provide further details of the background data.

Table 6-3 Annual change in EGW industries Australia LPI

Year To:	EGW industries Australia LPI	Annual Change %
Jun-2002	73.8	
Jun-2003	76.8	1.07%
Jun-2004	79.9	4.04%
Jun-2005	83.3	4.26%
Jun-2006	87.7	5.28%
Jun-2007	92.0	4.90%
Jun-2008	95.8	4.13%
Jun-2009	100.0	4.38%
Jun-2010	104.4	4.40%
Jun-2011	108.7	4.12%
Jun-2012	112.6	3.59%
10 Year Average %		**4.32%**

- **Figure 6-1 Annual change % of EGW industries Australia LPI vs. All industries Australia LPI**



6.3.4. WA labour

The second of the two cost escalation rates related to labour was included as a means to account for changes in general labour. The rate for WA was separated from the national rate as it was considered important to differentiate WA labour rate increases from the national average as a means to more closely reflect the actual costs.

SKM again used the data published by the ABS to develop this rate. The ABS 6345.0 Labour Price Index; Table 2a to 9a All WPI series: original (financial year index numbers for year ended June quarter); financial year index; total hourly rates of pay excluding bonuses; Western Australia; private and public; all industries; Series ID A2705992V was used for this purpose.

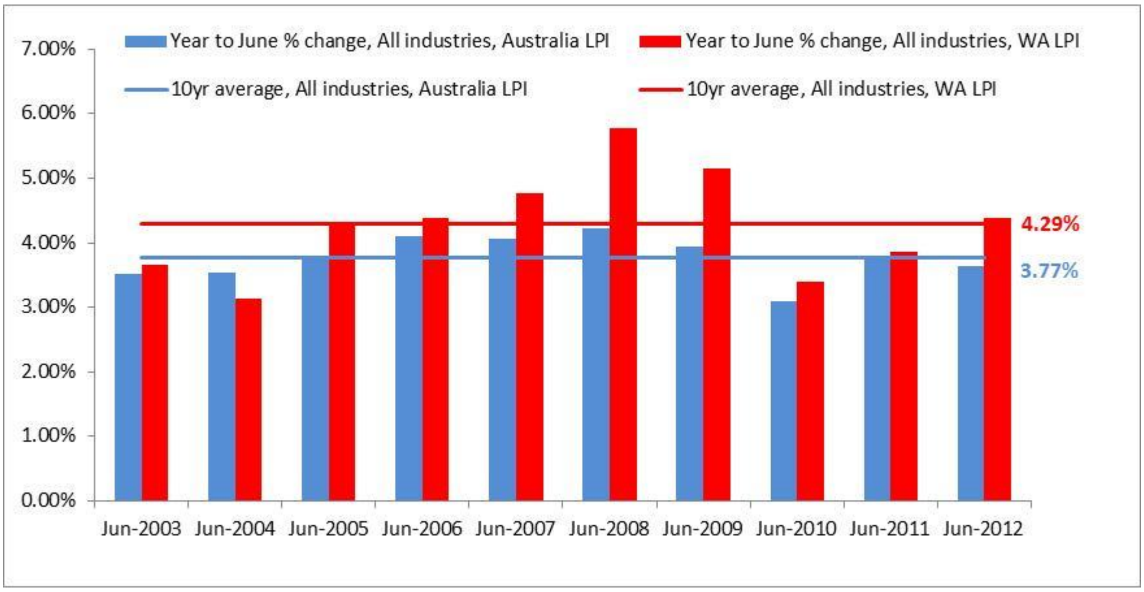
Table 6-4 and Figure 6-2 provide further details regarding the background data.

- **Table 6-4 Annual change in All industries WA LPI**

Year To:	All industries WA LPI	Annual Change %
Jun-2002	73.7	
Jun-2003	76.4	3.66%
Jun-2004	78.8	3.14%
Jun-2005	82.2	4.31%
Jun-2006	85.8	4.38%
Jun-2007	89.9	4.78%
Jun-2008	95.1	5.78%
Jun-2009	100.0	5.15%

Year To:	All industries WA LPI	Annual Change %
Jun-2010	103.4	3.40%
Jun-2011	107.4	3.87%
Jun-2012	112.1	4.38%
10 Year Average		**4.29%**

- **Figure 6-2 Annual change % of All industries WA LPI vs. All industries Australia LPI**



6.3.5. Australian to US dollar exchange

As internationally traded commodities used in SKM's forecasts, such as copper and steel, are traded in nominal US dollars (USD), the Australian dollar's (AUD's) relative position to the USD will, in itself, influence the cost of finished goods to an Australian utility. Where economic forecasts are presented in real terms these are converted to nominal USD using US CPI forecasts.

As a final step after determining forecast USD prices for each globally traded commodity, SKM converts the underlying commodity cost to AUD.

For this study, SKM considers the AUD/USD exchange rate to gradually decrease from the present 1.05 to 0.89 over the required forecast horizon. This foreign exchange forecast rate is based on the AER's decision on Queensland's Powerlink recent reset submission dated April 2012. This forecast is also consistent with the recent publication subscribed by SKM on forex forecast rate from NAB Research dated 24 September 2012.

6.3.6. Copper

When developing forecasts for the future annual market price position of the various materials' key cost drivers, SKM's methodology places greater weight on credible market prices than pure economic forecasts. SKM uses market forward prices as far as these are available in the future, and then a linear interpolation to future economic and other credible market forecasts beyond the time horizon covered by futures markets.

The emphasis within this process is to include as much recent and credible information as is available at the time of developing the forecast cost driver movements.

An example of the application of SKM's methodology is the process for developing future price positions for commodity based cost drivers such as aluminium, copper and oil, within the SKM model.

In this instance the process applied by SKM uses a five step approach. This approach is followed in order to produce specific data points between which a simple method of interpolation is able to be applied, in order to fill in any missing data points and arrive at the required market pricing positions. SKM's cost escalation model has a resolution of one month, and all prices are determined monthly, with annual averages used to smooth volatility from month to month.

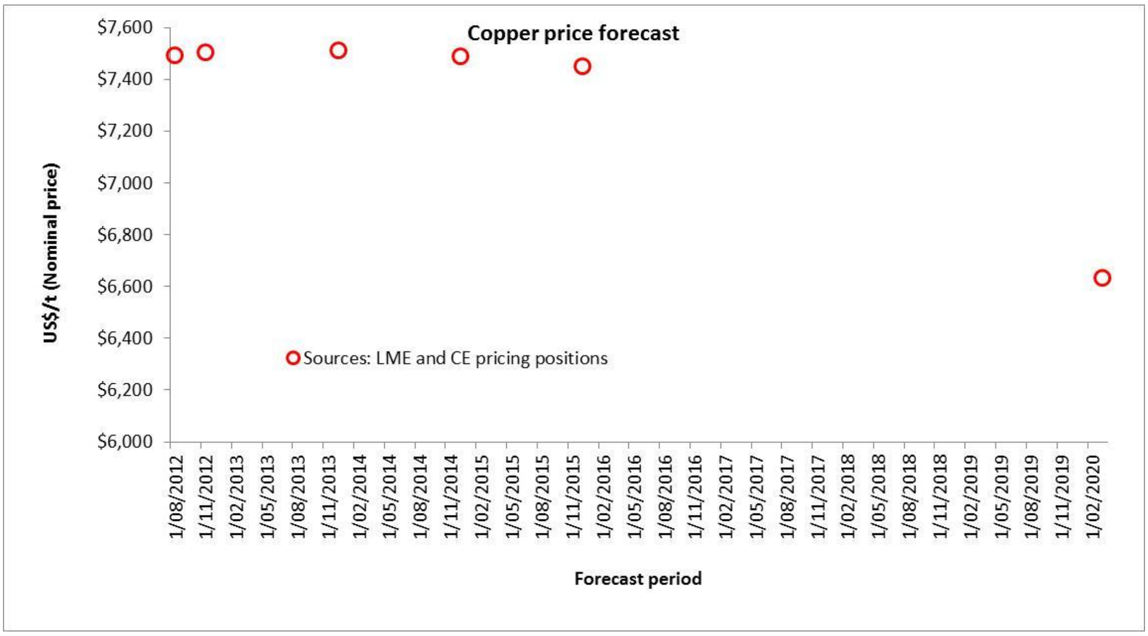
Because of the volatility in daily spot and futures markets, SKM uses monthly averages of such prices as the basis for developing its forecasts. The use of monthly averages assists to ensure that future prices are neither unnecessarily inflated, nor deflated, through the application of a daily peak, or trough, during the interpolation of prices for the commodity in question. The five steps involved are:

1) Determine the average of the most recent month of London Metal Exchange (LME) copper prices/tonne.
2) Determine the average of 3, December of +1 year, December of +2 year and December of +3 year months LME contract prices for the most recent month.
3) Determine the most recent Consensus Long-Term Forecasts position (taken as 7.5 years from survey date[5]).
4) Apply linear interpolation between each of the data points above.
5) Identify the June points for the relevant years in the interpolated results, and calculate annual year to June average prices as the underlying commodity cost movement to be used in the equipment escalation model.

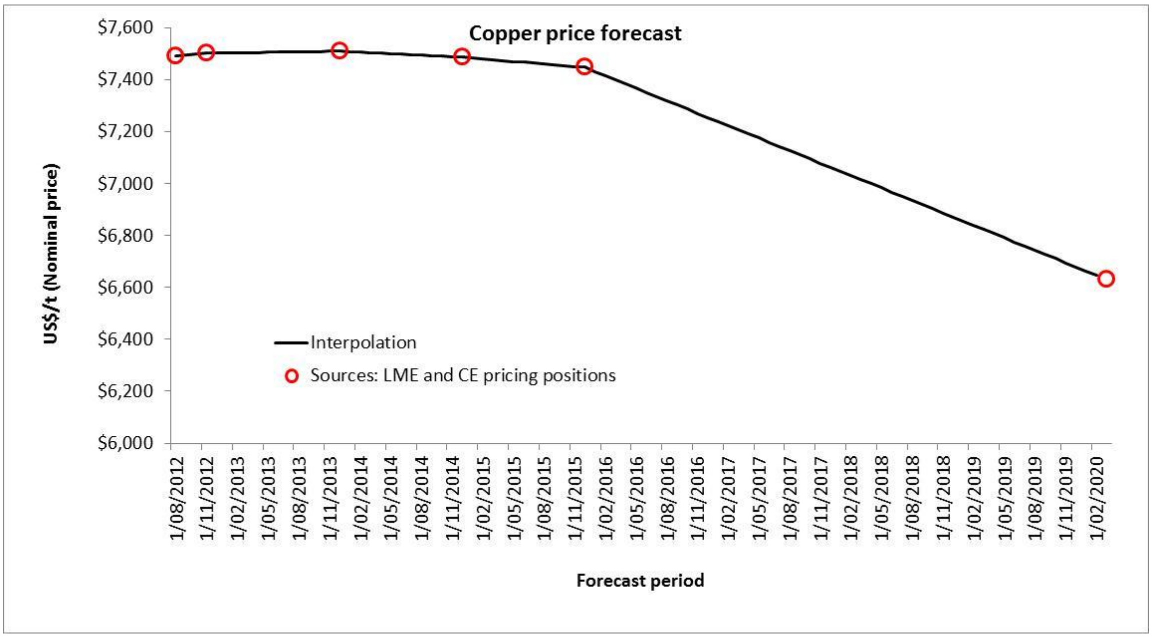
This methodology is illustrated in Figure 6-3 and Figure 6-4.

[5] The Consensus Long-term forecast is listed in the publication as a 5 – 10 year position. As a reasonable assumption, SKM consider the position to refer to the mid-point of this range, being 7.5 years, or 90 months. The long term (real) forecast is adjusted for US CPI to determine a long term (nominal) price. Market prices are by definition nominal.

- **Figure 6-3 Diagram of SKM methodology for Cu forecast price (Steps 1-3)**



- **Figure 6-4 Diagram of SKM methodology for Cu forecast price (Steps 4-5)**



The average year to June input numbers used during SKM's escalation modelling of the copper nominal prices are presented in Table 6-5. It has been converted to Australian dollars and the impact of the Australian carbon price mechanism has been duly considered. Refer Section 6.4 regarding the impact of Australian carbon price mechanism.

Table 6-5 Forecast average annual copper price (A$/tonne nominal)

Year end to	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18
Cu Price	$7,901	$7,290	$7,595	$7,846	$8,037	$8,060	$8,069
Annual Change		-7.73%	4.18%	3.31%	2.43%	0.29%	0.12%

6.3.7. Steel

SKM's methodology used for developing forward market positions for copper and aluminium is presently not considered suitable for steel, due to the lack of a clear benchmark steel futures market. SKM notes that the LME commenced trading in steel billet futures in February 2008 and the available future contract prices are applicable only for delivery to Dubai and Turkey[6]. While the steel billet is a semi-finished product, its price movement has a strong correlation with the end product like steel reinforcement bar (used for construction), and therefore its forecast or future price trend can be used to calculate the escalation rate for steel[7]. However, one of the limitations for using the LME forecast prices for steel billet is the unavailability of a longer term trend (prices available up to 15 months only).

Due to the above stated reasons, SKM has used the Consensus Economics forecast as the best currently available outlook for steel prices. Consensus Economics provides quarterly forecast prices in the short term, and a "long term" (5-10 year) price.

SKM has used the August 2012 Consensus Economics survey report to compile the steel escalation information provided in this report. This publication provided quarterly forecast market prices for steel from present month (i.e. August 2012) to +26 months, as well as a long-term forecast pricing position i.e. annual average of +2 years, +3 years, +4 years, and +5–10 year position which is taken as 7.5 years (90 months) from survey date.

Consensus Economics provides two separate forecasts for steel, using hot rolled coil (HRC) steel prices in the USA domestic market and the other the European domestic market. The Consensus Economics US HRC price forecasts are presented in US$ per *short ton,* which SKM converts into metric tonnes for consistency with the European price.

SKM's methodology uses a five step approach to produce specific data points between which a simple method of interpolation is able to be applied, in order to fill in any missing data points and arrive at the required pricing positions.

Because of the volatility in daily spot and futures markets, SKM uses the monthly average of these two forecasts (US HRC and EU HRC) as its steel price inputs to the cost escalation modelling process. The use of monthly averages assists to ensure that future prices are neither

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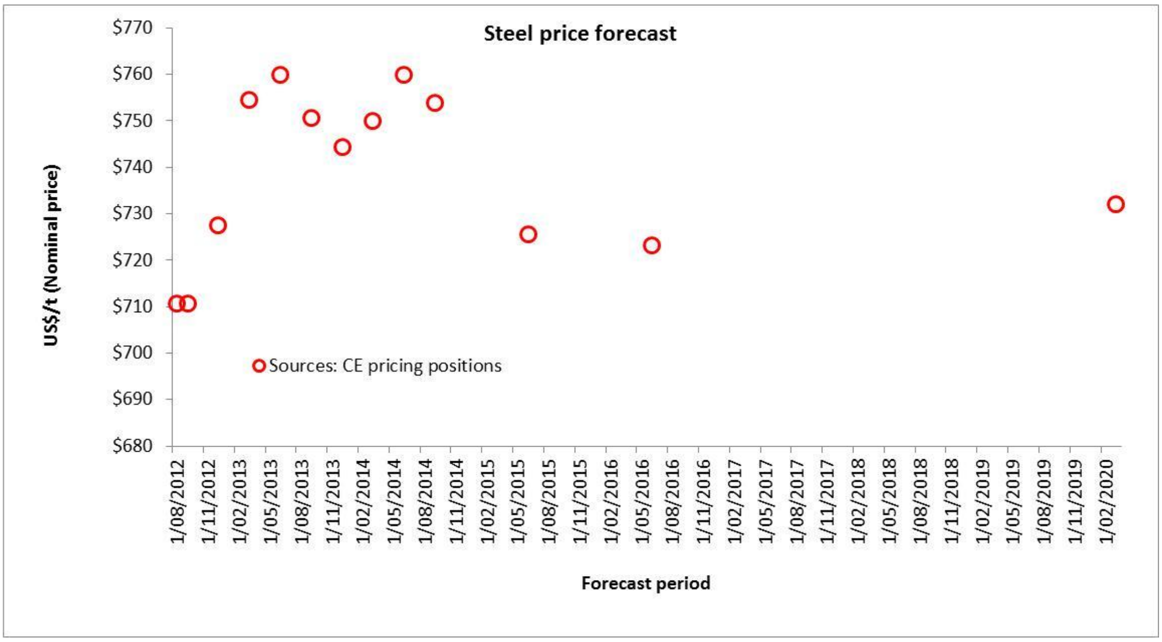
[6] http://www.lme.co.uk/5723.asp
[7] http://www.lme.com/steel-faqs.asp

unnecessarily inflated, nor deflated, through the application of a daily peak, or trough, during the interpolation of prices for the commodity in question. The five steps involved are:

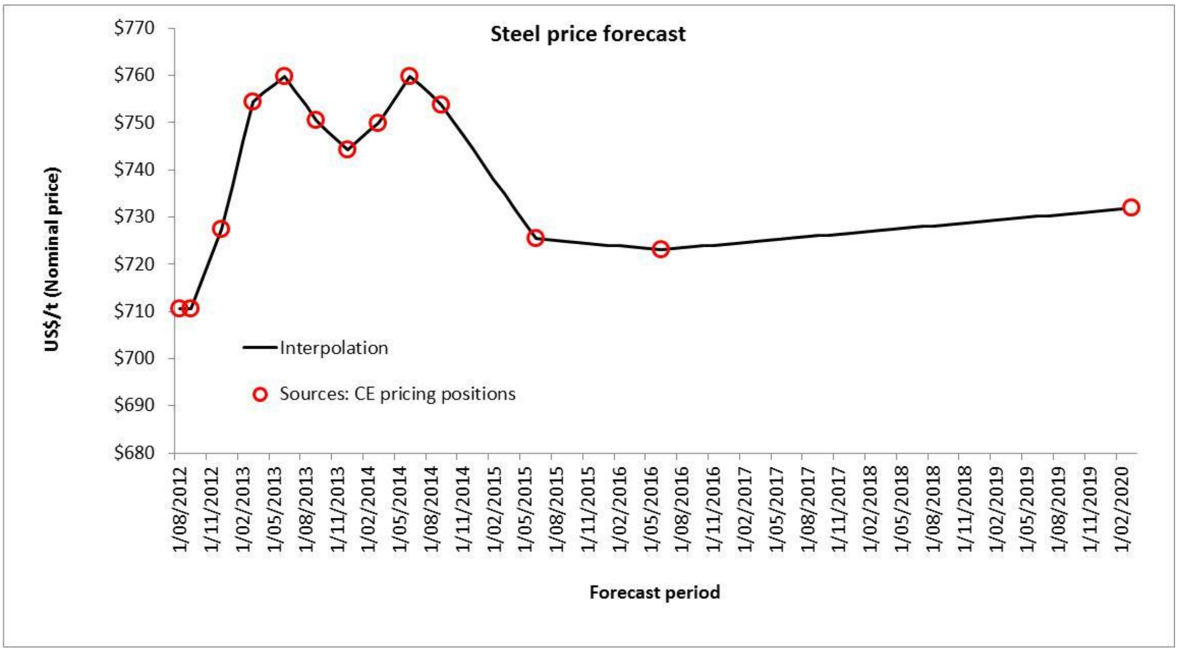
1) Determine the average of the most recent month USA and European Consensus Economics survey average HRC steel price/ metric tonne.
2) Determine the average of the most recent USA and European 2, 5, 8, 11, 14, 17, 20, 23, 26, June of +2 years, June of +3 years, and June of +4 years months Consensus Economics survey average HRC steel price/ metric tonne.
3) Determine the average of the most recent USA and European Consensus Economics survey of Long-Term Forecasts positions average HRC steel price/ metric tonne.
4) Apply linear interpolation between each of the above data points.
5) Identify the June data points for the relevant years in the interpolated results, and calculate annual year to June average points from these June points, and feed these prices into the model.

This methodology is illustrated in Figure 6-5 and Figure 6-6.

- **Figure 6-5 Diagram of SKM methodology for steel forecast price (Steps 1-3)**



- **Figure 6-6 Diagram of SKM methodology for steel forecast price (Steps 4-5)**



The average year to June input numbers used during SKM's esalation modelling of the steel nominal prices are presented in Table 6-6. It has been converted to Australian dollar and the impact of the Australian carbon price mechanism has been duly considered. Refer Section 6.4 regarding the impact of Australian carbon price mechanism.

- **Table 6-6 Forecasted average annual steel price (A$/metric tonne nominal)**

Year end to	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18
Steel Price	$714	$713	$760	$778	$784	$806	$831
Annual Change		-0.01%	6.55%	2.41%	0.71%	2.76%	3.19%

6.3.8. Engineering construction

The Australian Construction Industry Forum (ACIF)[8] is the peak consultative organisation of the building and construction sectors in Australia. The ACIF has established the Construction Forecasting Council (CFC)[9] through which it provides a tool kit of analysis and information. SKM referred to a range of forecast trends generated by the CFC as a proxy for the future movement in the price of civil work or engineering type construction work in the WA market.

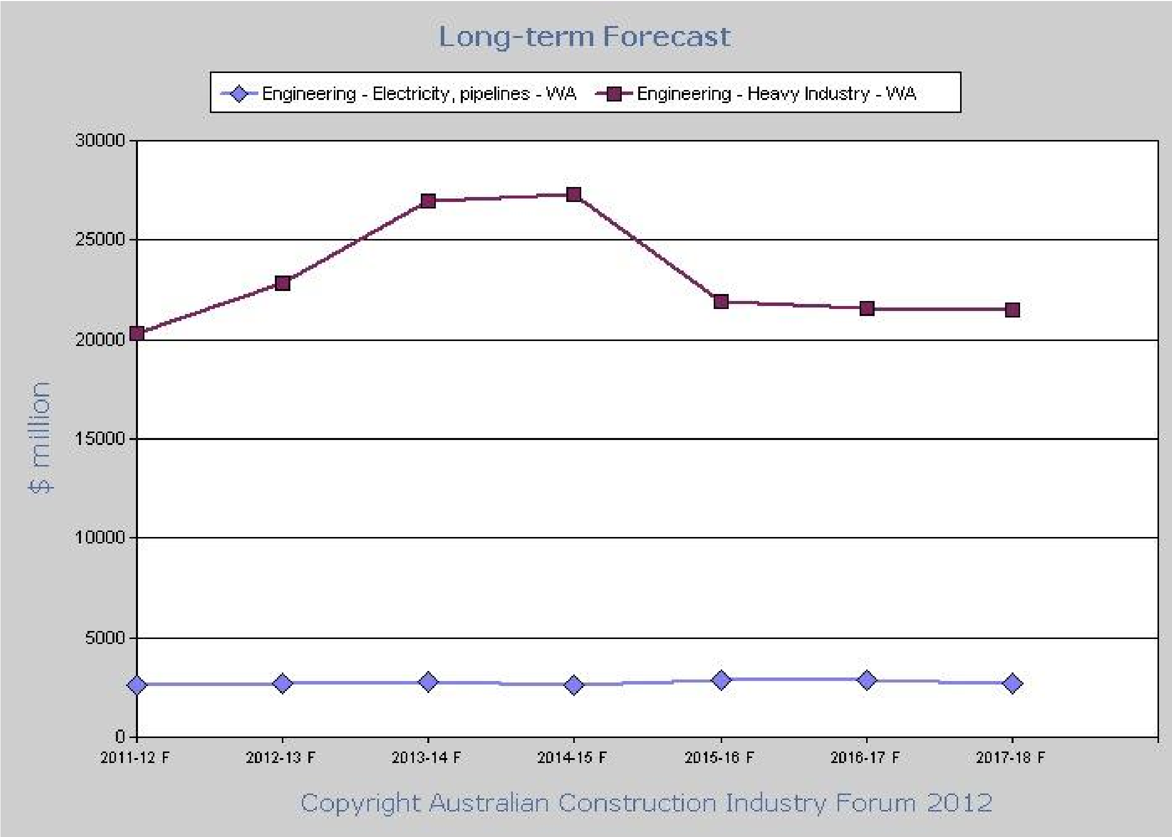
In commenting on activity in construction related to the electricity and pipeline industry, the CFC in its most recent commentary (dated April 2012) notes the following:

[8] http://www.acif.com.au/
[9] http://www.cfc.acif.com.au/cfcinfo.asp

> *"Electricity and pipelines are a large and growing category. A significant driver of the long term trend in this category is investment in infrastructure required to upgrade and increase the capacity of networks. Further, we see the impact of policy levers on this class, such as the CPM and the RET and these are driving expenditure on large renewables projects, such as $2bn on a wind farm in Silverton and $2bn on the Solar Dawn project"*[10].

This statement along with the commentary on construction activities related to heavy industry is illustrated in Figure 6-7 which shows forecast trends in WA.

Figure 6-7 Engineering (electricity & pipeline) construction volume in Australia and WA



This outlook is likely to sustain the market demand for related construction materials and activities, and thus the resultant market prices. The CFC also provides forecasts of the price index related to 'engineering' construction category for overall Australia region. This is illustrated in Figure 6-8 and the figures with the calculated annual % change (or escalation factor) are shown in Table 6-7.

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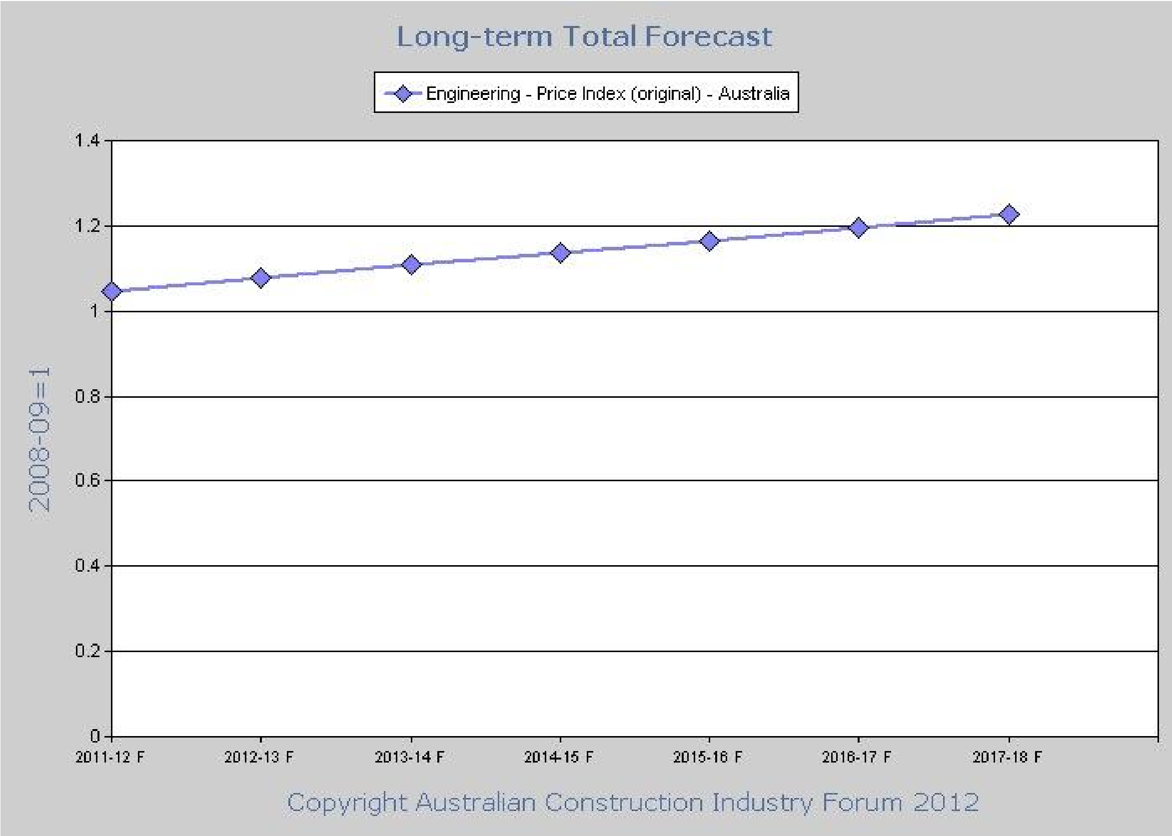
[10] http://www.acif.com.au/forecasts/summary/highlights-for-engineering-construction

- **Figure 6-8 Australia wide engineering construction price index forecast**



- **Table 6-7 Australia wide engineering construction nominal escalation factor forecast**

Year end to	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18
Price Index (2008-09 = 1.00)	1.046	1.079	1.108	1.136	1.166	1.196	1.226
% change		3.10%	2.75%	2.49%	2.61%	2.59%	2.54%

6.4. Carbon price mechanism impact

SKM has modelled the impact of an introduction of a carbon price mechanism in Australia on the future price of the commodities and the results shows that the impact ranges from being very small to nil. The inclusion of an Australian carbon price to the commodities (copper and steel) price results in the upper extent of impact of the carbon price mechanism; assuming that the cost increase experienced by manufacturers in Australia can be passed through in full. However, in reality the actual impact (or lack of) will be affected by various factors which are discussed below:

- The impact and therefore the inclusion of the Australian carbon price on the power station capital asset classes is dependent on the asset component make-up profile, prospective asset/project suppliers portfolio, market dynamics, competition and international pricing pressure. It is noted most of the power station capital plant equipment will be sourced from the international market which does not have any impact of an Australian carbon price mechanism. Only assets which are locally manufactured and for which the scope for international competition is negligible, will experience and be able to pass through the local carbon price impact. The magnitude of this impact is however very small and the extent of the pass through to the customer is uncertain. Further, given that some locally manufactured items will be made from imported materials, the international price may also act to constrain local price impacts.

- The assistance level for the Emission Intensive Trade Exposed (EITE) industries is generous for industries in the 'High' emission category and is designed to gradually decrease as the affected industries improve their efficiency and productivity increases in due course. This existing trade assistance is effective at vastly reducing but not eliminating this impact.

- Compared to aluminium production (for example), the emission intensity (measured in *tonnes of* CO_2 *emitted per tonne of commodity produced*) of copper and steel production are relatively low. Therefore, the additional cost of carbon emission for copper and steel production is relatively lower.

- Post July 2015 the Australian carbon price mechanism will be linked with the European Union Emission Trading Scheme allowing the trade of the carbon permits between the two markets. The future carbon emission permit price from the EU ETS market is considerably lower than the expected Australian future price of carbon permission modelled by the Australian Treasury. SKM has considered 50:50 weightings between the EU ETS future price and the Australian Treasury forecasted price for the carbon permits from July 2015 onwards. This provision has further reduced the impact of Australian carbon price mechanism on commodities price.

Based on these factors, SKM has not included the impact of the Australian carbon cost to the provided forecast of commodities price due to the anticipated negligible impact. The detailed description of the SKM modelling steps for calculating the impact of carbon price mechanism is provided in **Appendix A**.

6.5. Weighting of the cost drivers

An understanding of the appropriate application of weighting for each cost driver to each item of plant and equipment has been developed by SKM over time as a result of a series of strategic surveys of Australian electricity utility plant and equipment cost, in-depth discussion with the manufacturers and suppliers, a detailed understanding of rise and fall clauses in client procurement contracts, and advice from SKM's team of professional economists and engineers.

The power station, connection switchyard and the overhead transmission line costs are disaggregated into the respective underlying commodity component cost items and the escalation rate of each individual cost drivers are applied proportionally, to understand the effect of escalation of each cost driver to the overall asset costs.

6.6. Capital cost escalation factors

The final nominal capital cost escalation factors determined by SKM for the annual forecast year to end of June for the next 5 years are shown in Table 6-8.

- **Table 6-8 Nominal capital cost composite escalation factor annual forecast year to June for next 5 years**

Assets	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17
Power Station	1.62%	4.39%	3.33%	2.85%	3.07%

The nominal escalation factors in this table are the resulting averages of the cost driver indices weighted by the cost items makeup proportion of the respective capital costs. For example, the component makeup of the power station capital cost estimate appears in Table 2-1 of this report. Each of the listed cost items is influenced by multiple underlying commodity cost driver indices in different proportions.

Using the escalation factors in Table 6-8, the total capital cost estimate of the power station on **1 April 2015** is forecasted as **A$132,379,701** which equates to **A$829/kW**[11]. This forecast estimate is as per Section 2.3.1 (a) of the Market Procedure for MRCP (version 5) which requires the estimate as at April in Year 3 of the Reserve Capacity Cycle.

6.7. Fixed operational & maintenance cost escalation factors

The final nominal operating cost escalation factors determined by SKM for the annual forecast year to June for the next 5 years are shown in Table 6-9.

- **Table 6-9 Nominal fixed O&M cost composite escalation factor annual forecast year to June for next 5 years**

Assets	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17
Power Station	3.79%	3.60%	3.61%	3.62%	3.62%
Connection Switchyard	4.32%	4.32%	4.32%	4.32%	4.32%
Overhead Transmission Line	4.32%	4.32%	4.32%	4.32%	4.32%

The fixed O&M cost escalation factors for the connection switchyard and the overhead transmission line follows the Australian Electricity Gas Water Labour Price Index. The fixed O&M cost escalation factor for the power station is the resulting average of the cost driver indices

[11] Based on 159.6 MW net output defined in section 2.5.

weighted by its cost items makeup proportion. The makeup components of the power station fixed O&M cost appears in Table 3-1 of this report. Each of the listed cost items is influenced by one or multiple cost driver indices.

Using the escalation factors in Table 6-9, the fixed O&M cost estimate of the power station in **October 2015** is forecasted as **A$2.353million per annum** (or A$11.76million for a 5 years period in Oct 2015 dollars).

Similarly, the fixed O&M cost estimate of the connection switchyard and the overhead transmission line in **October 2015** are **A$66,550 per annum** (or A$332,748 for a 5 years period in Oct 2015 dollar) and **A$1,297 per annum** (or A$6,483 for a 5 years period in Oct 2015 dollars) respectively.

These forecast estimates are as per Section 2.5.6 (a) of the Market Procedure for MRCP (version 5) which requires the fixed O&M estimates as at October in Year 3 of the Reserve Capacity Cycle.

7. Calculation of the M factor

7.1. Introduction

The allowance, M, to be included for "Legal, Insurance, Approvals, Other Costs and Contingencies" is to be estimated in accordance with Section 1.12.1 of the Market Procedure as:

> *The IMO shall engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:*
>
> *(a) Legal costs associated with the design and construction of the power station;*
> *(b) Financing costs associated with equity raising;*
> *(c) Insurance costs associated with the project development phase;*
> *(d) Approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;*
> *(e) Other costs reasonably incurred in the design and management of the power station construction; and*
> *(f) Contingency costs.*

The factor M is applied to the estimated capital cost of the power station expressed in AUD/kW. The capital cost in the method to which the M factor is applied is the power plant capital costs excluding transmission connection capital cost and land capital cost (which are separate factors).

7.2. Implications of the specified procedure

The following assumptions regarding the structure of the assumed OCGT project can be derived from the procedures:

- The costs are based on the costs to develop a single unit "E" class liquid fuelled gas turbine plant of nominal capacity 160MW. When calculating specific costs the capacity at 41°C is considered.
- The plant operates at a low capacity factor (2%).
- The plant would be developed upon industrial land. The nominated locales are areas where existing similar plants are located and other industrial facilities:
  - Collie Region.
  - Kemerton Industrial Park Region.
  - Pinjar Region.
  - Kwinana Region.
  - North Country Region.
  - Kalgoorlie Region.

- The costs of acquiring land are excluded from the M parameter.
- The power plant is delivered on a single package, turnkey EPC contract.
- The power plant costs are estimated based on a notional project being committed at the current time. The commissioning time may be of the order of three years in the future to coincide with the period the capacity auction was undertaken for. Since the delivery time of such a gas turbine can be up to 2 years from the time of EPC contract closure, the factors should consider that prices for plant etc may be subject to 1 year of variation between the time of the auction and the time of financial closure of the EPC contract.
- The procedure is not explicit in identifying whether a project financed model or a corporate financed model of the power station development should be assumed. The discussion in the procedure regarding the project being eligible to receive a 'Long Term Special Price Arrangement' suggests project finance whereas the relatively low debt issuance cost prescribed (12.5bp) and the specification for comparator companies in the WACC review suggest corporate finance. The project development costs for a project financed project tend to be higher due to additional processes undertaken (preparation, issue and attendance upon Information Memoranda, debt syndication, due diligence reviews, etc.). It is considered appropriate that the form of financing model be more appropriately considered within the development of the WACC parameter than within the M parameter.
- The recognition of costs attributable to the project development commences at the time of the auction that is taken to be approximately 1 year before financial close and prior to approval and procurement processes being undertaken. The cost of these processes is thus included within the M factor.

7.3. Derivation of the M factor for 2013

7.3.1. Values applied in 2012

Costs for indirect capital cost elements vary widely between projects and there is a lack of specific data from the WA market. Consideration is given to the 2012 scope and values and whether any changes are considered appropriate in the 2013 review.

The parameters applied in the 2012 review for the M factor are listed in Table 7-1. These components are discussed below.

- **Table 7-1 Calculation of the M factor in 2012**

Component of 'M'	2012 % of EPC
Project Management	1.8%
Project Insurance	0.4%
Cost of Raising Capital	3%
Environmental Approvals	0.8%
Legal Costs	1.1%
Owner's Engineer - Part A (Including concept design, specification, tendering, contract negotiations)	0.4%
Owner's Engineer - Part B (Including construction phase OE costs, oversee project, witness tests & commissioning)	2.8%
Initial Spares requirements	0.8%
Site Services (provision of potable water, construction power, communications, domestic sewerage etc. at site)	0.1%
Start-up Costs	2.0%
Contingencies	5.0%
Total M	**18.2%**

These were applied to a base EPC capex estimate of A$126.4million in 2012. The following analysis is based on a 2013 estimate of A$121.7million.

The prescribed method is unchanged from the 2012 update.

7.3.2. Project management and owner's engineering

These costs typically are made up of consulting engineering services and have been broken down into three components – project management by the developer / owner and owner's engineering costs which may be via a contract with a services provider. The latter are separated into pre and post commitment costs. As before, we have used the producer price indices to escalate the 2012 costs. The change in producer price indices (PPI) (Australia wide) for "Engineering design and engineering consulting services" from June 2011 to June 2012 has been 5.0%[12].

7.3.3. Legal

The legal costs allowed in 2012 amounted to A$1.46million. This would be expected to cover a full service such as for a project financed project. For a corporate financed project, delivered on an EPC basis, the project agreements are more limited (EPC, connection agreement, loan agreement, land purchase, fuel supply agreement, etc.). The allowance previously applied should suffice.

[12] ABS "6427.0 Producer Price Indexes, Australia", Table 22. Selected output of division M professional, scientific and technical services, group and class index numbers, Series A2314202T.

The 2012 amount has been escalated at the PPI rate for "Legal services" of 4.1%[13].

7.3.4. Insurance

The insurances purchased by the owners are highly dependent on the contractual framework used to deliver the power station. Insurances required during construction may include:

- Insurance to cover any assets the owner carries during construction, this may include early order plant.
- Owner's public liability and professional indemnity insurances.
- Other owners insurances during construction.

An allowance of 0.5% has been provided in the margin M to cater for these costs. This is an increase from the 2012 update due to recent market information on increases in insurance premiums.

7.3.5. Approvals

The cost of environmental approvals depends on the 'level of assessment' as set by the Environmental Protection Authority (EPA) under the Environmental Protection Act 1986 (the EP Act) and whether the development would affect any 'Matters of National Environmental Significance', thereby triggering Commonwealth approvals processes (the Environmental Protection and Biodiversity Act).

Should the State level be set to 'Assessment on Referral Information' (ARI) then costs may be significantly lower than the level of assessment being set to 'Public Environmental Review' (PER), in accordance with the EP Act. The significance of likely environmental impacts, scale of the development and its location, discharge requirements, technology options etc. will decide what level of assessment is required by the regulator. This includes factors such as (but not limited to) whether the site is greenfield or brownfield, existing environment (such as local airshed, water resources, proximity of sensitive receptors (dwellings), etc.), requirement for specialist studies to support the referral and community expectations.

For an ARI-type level of assessment, expected costs would be of the order of A$100K to A$500K, varying with the level of desktop environmental studies required. The core of this is the development of approvals strategy, some preliminary environmental baseline studies (largely desktop), consultation with the regulators, and general project management of the process.

If the project is assigned a PER level of assessment the amount of work can be far more significant. In addition to the above, the project may require detailed environmental studies relevant to the project area, community consultation, as well as a significant review and response

[13] ABS op cit, Series A2314223C.

to comment period. Indicative costs would be in the order of A$600K to A$2.0million for this level, depending upon the significance of the environmental factors.

As for application and process fees, these are insignificant in comparison to the cost of getting the studies and documentation ready for the regulators decision making processes.

The ARI level processes have been amended and this makes the costs somewhat more uncertain. At this time the impact is thought to be more upon schedule than the cost of the processes.

An OCGT project operating at a very low capacity factor, located in an existing precinct and sited sensitively with regards to other stakeholders, as would be expected in commercial practice, is thought more likely to be able to use the simpler approvals process.

For this review a midrange allowance of A$1.0million is applied. This is unchanged from the 2012 update.

7.4. Financing costs associated with equity raising

The specification for consideration of the WACC parameters requires comparator companies with market capitalisation of at least A$200million. For "typical" parameters of P/E ≈ 15 and payout ratio of 60% internal equity growth would be in the order of A$5million/year. A company of this scale would be expected to need to raise equity to finance a project of this scale at an assumed 40% gearing, as prescribed in the method. For larger energy companies this may not necessarily be the case.

For a project financed project, the cost of raising equity would include the sponsor's equity raising costs and also the costs of establishing the project vehicle.

The actual cost will be highly specific to the circumstances of the project and its developer.

In 2012 an allowance of 3% was provided for the "Cost of raising capital", on the basis this was equity raising costs only (a debt issuance cost being included within the WACC).

The allowance of approximately 3% is still considered appropriate.

7.5. Start-up costs

Start-up costs were considered for the first time in 2012. For an OCGT plant the primary start-up costs would include:

- Costs of recruiting and training staff and employing staff during the period prior to commercial operations.
- Cost of fuel and consumables used in testing and commissioning.

A 2% allowance is recommended.

7.6. Initial spares

The 2012 allowance for initial spares of 0.8% is considered reasonable.

7.7. Contingency costs

The "contingency" allowed in 2012 was 5%, reflecting an allowance for minor and unidentified items. These could include things such as office fit-out, office equipment, pre-work on the site prior to the EPC contract (e.g. access, fencing/security, removal of debris or contamination etc to facilitate studies), special tools etc.

For this review, an overall contingency allowance of 5% is included, consistent with SKM's interpretation of the Scope of Works (detailed in **Appendix C**) and previous year's reports.

7.8. Overall M factor

The M factor resulting from this analysis is given in Table 7-2.

Table 7-2 Calculation of M factor 2013

Component of 'M'	2012 % of EPC	2013 % of EPC	2013 $k AUD
Project Management	1.80%	1.96%	$2,391
Project Insurance	0.40%	0.50%	$609
Cost of Raising Capital	3.00%	3.00%	$3,651
Environmental Approvals	0.80%	0.82%	$1,000
Legal Costs	1.10%	1.19%	$1,448
Owner's Engineers - Part A (including concept design, specification, tendering, contract negotiations)	0.40%	0.44%	$531
Owner's Engineers - Part B (including construction phase OE costs, oversee project, witness tests & commissioning)	2.80%	3.06%	$3,718
Initial Spares requirements	0.80%	0.80%	$974
Site Services (provision of potable water, construction power, communications, domestic sewerage etc. at site)	0.10%	0.10%	$122
Start-up costs	2.00%	2.00%	$2,434
Contingencies	5.00%	5.00%	$6,085
Total M	**18.20%**	**18.87%**	**$22,962**

As noted above, the 160MW OCGT plant capital cost estimate and 'M' factor combined are calculated to reflect a "most likely" outcome, consistent with SKM's interpretation of the scope of work.

Appendix A SKM modelling for impact of carbon price mechanism

The introduction of an Australian carbon price mechanism has imposed costs on emitters of greenhouse gases from July 2012. However, the existing assistance for "emission intensive trade exposed (EITE)" industries is designed to reduce the impact of this mechanism on some emissions intensive industries such as Copper and Steel during the initial stages of this scheme.

The elements of carbon price mechanism impact that were included in SKM modelling are:

- Projected Australian carbon permit prices based on Treasury modelling;
- The recent (28 August 2012) announcement that from July 2015 the Australian CEF scheme will be linked with the current European carbon pricing scheme allowing the trading of permits between the two schemes;
- Emissions intensity of emission intensive materials[14];
- Percentage of costs passed through to take account of EITE assistance levels which are assumed to reduce regularly over the foreseeable future; and
- Expectation/appreciation of an OCGT power station asset class, its component make-up profile, supplier's portfolio and available competitors, open market dynamics and international pricing pressure.

The effect of CEF on cost drivers is modelled through the assignment of greenhouse emission intensity to each of the cost drivers. The emission intensity or embodied emission is described in *Tonnes of CO_2 emitted per tonnes of produced commodity* and is prescribed by the CEF scheme. These factors are multiplied by projected emissions permit prices to derive an additional "carbon price" effect for each of the individual input drivers or commodities. The model allows for different treatment of EITE commodities (e.g. Copper), in line with proposed compensation measures included in the December 2008 CEF White Paper and subsequent policy announcements. The model also draws on the expectation or appreciation of an OCGT power station on the origin of all its asset categories (i.e. local vs. import vs. mix) to accurately consider the extent of influence of Australian carbon price in the production of such assets.

We consider that the impact of the Australian carbon price mechanism on imported material and components will be immaterial as the Australian carbon price is expected to have no or negligible impact on the international price of materials. While it is difficult to gauge the impact of the carbon price on locally manufactured materials and items of equipment, our methodology allows an estimate to be made of additional costs to local manufacturers which they might be able to pass (0% to 100%) through to customers. As such, we would expect this to set the upper limit for locally produced products.

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[14] SKM has based its assessment of emissions intensity on the Commonwealth Government's assessment of emissions intensity of EITE industries, using actual Australian manufacturing data.

The calculations of carbon permit prices are summarised in Table 3. SKM has used nominal permit prices as the primary CEF input to the cost escalation model from FY2012-13 to FY2014-15. SKM has used a 50:50 split of the forecasted Treasury permit prices and the average August 2012 European Energy Exchange[15] future contract prices for carbon permits from FY2015-16 onwards. An exchange rate of AUD 1 = EUR 0.73[16] has been used to convert European permit prices to nominal Australian prices.

Table 3 Australian carbon permit nominal prices

YE to June (Nominal)		Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18
Australian Treasury forecast	(A$/$CO_2$t)	NA	$23.00	$24.15	$25.40	$28.60	$30.51	$32.74
EU ETS future market price	(A$/$CO_2$t)					$12.38	$13.05	$13.32
50:50 weightings						$20.49	$21.78	$23.03
Carbon Price	(A$/$CO_2$t)		$23.00	$24.15	$25.40	$20.49	$21.78	$23.03

Source: SKM interpolation of CEF Treasury modelling permit projections (2010 and 2020), European Energy Exchange carbon permit futures.
Note: 2012-13 administered price starting at $23 and increasing at 2.5% real.

Coupled with the CEF price, the emissions intensity of each input cost driver is required to determine the anticipated impact on input prices. SKM has sourced emissions intensity figures from Commonwealth Government assessments of emissions intensive industries as shown in Table 4.

Assistance for EITE industries is also part of current policy, with the percentage level of assistance sourced from Department of Climate Change documents relating to the operation of the EITE assistance scheme. The factors used in the CEF modelling are shown in Table 4 below. For EITE industries rated as “High” assistance starts at 94.5% in 2012-13 financial year and reduces by the carbon productivity contribution of 1.3% pa.

Table 4 Emissions intensity and pass-through assistance | year end to June

Commodity	EITE Asst	Emission Intensity [t CO_2e/t]	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18
Copper	High	1.95	NA	94.5%	93.3%	92.1%	90.9%	89.7%	88.5%
Steel	High	2.37	NA	94.5%	93.3%	92.1%	90.9%	89.7%	88.5%

Source: Commonwealth Government

[15] European Energy Exchange http://www.eex.com
[16] Forecast value used by National Institute of Economic and Industry Research (NIEIR) in report to the Australian Energy Market Operator (AEMO) for the National Electricity Forecasting Report dated May 2012.

Pass-through coefficients for each of these price impacts have been developed based on expected EITE assistance levels.

SKM has calculated the expected price impact on each of these commodities by multiplying the carbon price by the emissions intensity, subtracting the percentage impact of EITE existing assistance, to determine a per unit (tonne) emissions cost for each commodity. This impact was then added to the base forecast to determine a future price path including carbon price mechanism cost impacts. SKM has assumed that the carbon price mechanism and the EITE assistance scheme will continue to exist in the same form to 2020.

Appendix B Estimate Classification Criteria

APPENDIX B2 ESTIMATE CLASSIFICATION CRITERIA

The following table indicates the requirements for compiling capital cost estimates to the nominated accuracy, and also as a basis for the review process at this phase of the study. This is a guide only and may vary in some areas due to the documentation made available at the time the study period commences.

	Class 4 *Order of Magnitude/Concept*	Class 3 *Pre-Feasibility Study (PFS)*	Class 2 *Feasibility Study (FS)*	Class 1 *Definitive Estimate*
METHODOLOGY	Capacity factored (1) Equipment Factored (2) Historical data/Parametric models	Combination of MTO's, budget pricing, factors and semi-detailed unit rates	Detailed MTO's, detailed unit costs, budget pricing for all major equipment. Defined equipment list	Combination of commitments, awarded contracts, defined unit rates & detailed MTO's
PURPOSE	Preliminary economic and technical Investigation. Project screening. Comparison of alternatives, configurations and options.	Economic Feasibility of one or more chosen options.	Project Approval and basis of securing financing. "Bankable " study	Detailed Control. Target measurement Change/Variation Monitor and control of implementation phase.
BASIS OF ESTIMATE				
Accuracy - Indicative Range	±30% to ±100%	±20%to ±25%	±10%to ±15%	±5% to ±10%
Accuracy Development	Judgmental	Evaluated	@Risk Detail Analysis	@Risk Detail Analysis
Level of Project Definition	0% to 5%	10% to 30%	30% to 70%	70% to 100%
Level of Engineering(% of total)	0 to 2%	2 to 5%	15 to 30%	30 to 100%
Expected Contingency Range	25% to 40%	15% to 20%	10% to 15%	5% to 10%
Contracting Strategy	Assumed	Preliminary	Defined	In Place
SITE				
Location	Assumed	Specific	Specific	Final
Maps and Surveys	None	Preliminary	Some detail	Detail
Soil Tests & Geotechnical	None	Preliminary	Final	Final
Site Visits	Not Required	Desirable	Essential	Construction Start
Construction Support	Assumed	Proposed method	Detail support	Final
Construction site Agreement	Assumed	Assumed	Prelim discussion	Final / In Place
Delivery Strategy	Assumed	Preliminary	Defined	Fixed
Labour Awards	None	Assessed	Detailed basis	Actual
GENERAL PROJECT DATA				
Project Scope Description	General	Defined	Defined	Defined
Plant Production/Facility Capacity	Identified	Defined	Defined	Defined
Hydrology and Soils Report	Assumed	Defined	Defined	Actual
Integrated Project Plan	General	Preliminary	Specific	Fixed
Project Master Schedule	Assessed	Preliminary	Detailed	Defined
Escalation Strategy	None	Preliminary	Defined	Defined
Work Breakdown Structure (WBS)	Outlined	Preliminary	Complete	Fixed/Package
Project Code of Accounts	None	Preliminary	Defined	Complete
Foreign Exchange	None	Preliminary	Defined/Agreed	Fixed
Contingency/Accuracy Strategy	Assessed/Factored	Deterministic	Probabilistic	Detail calc. on ETC
Estimate Basis Document	Outlined	Defined	Detailed	Detailed
ENGINEERING DELIVERABLES				
Design Criteria	Outlined	Preliminary	Optimised/Final	Fixed
Technology	Existing	Selected Options	Confirmed/Complete	Complete
Block Flow Diagrams	Basic	Preliminary/Complete	Optimised/Final	Complete
Plot Plans	None	Preliminary	Detailed	Complete
Process Flow Diagrams (PFD's)	None	Started/Preliminary	Optimised/Final	Complete
Utility Flow Diagrams (UFD's)	Outlined	Started/Preliminary	Preliminary/Complete	Complete
Piping & Instr. Diagrams (P&ID's)	None	Outlined	Optimised/Final	Complete
Heat & Material Balances	None	Preliminary	Optimised/Final	Complete
Process Equipment List	None	Preliminary	Detailed	Complete
Utility Equipment List	None	Preliminary	Detailed	Complete
Electrical Single Line Diagrams	None	Preliminary	Preliminary/Detailed	Complete
Specifications & Data Sheets	None	Preliminary	Detailed	Complete
General Arrangement Drawings	None	Preliminary	Approved for Design	Complete
Spare Parts Inventory	None	% of Direct Costs	Detailed	Complete
Detailed Design Drawings	None	None	None	Preliminary/Complete
CAPITAL COST ESTIMATE				
Direct Costs	Factored	Combination	Detail	Actual/Detail
Indirect Costs	Factored	Combination	Detail	Actual/Detail
Major Equipment Costs	Data Base / Factored	Single Source	Multiple Source	Fixed Tender
Civil Work	Rough quantity	Preliminary	Detailed Take-off	Tender Prices/Contracts
Structural Work	$/unit vol.	Prelim take-off	Detailed Take-off	Tender Prices/Contracts
Piping & Instrumentation	% Machinery	Prelim take-off / %	Detailed Take-off	Tender Prices/Contracts
Electrical	$/kW	Prelim take-off	Detailed Take-off	Detailed/Contracts
Installation	Factored/%	Site Hours/Rates	Site Hours/Rates	Site Hours/Contracts
Owners Costs	Factored/%	Excluded	Provided	Detailed

Appendix C Scope of work

C.1 Project scope

SKM shall provide the following estimates and information.

C.1.1 Development of costs for the power station

1. Advice including an estimate of the costs associated with engineering, procurement and construction of the Power Station as at April in Year 3 of the Reserve Capacity Cycle. This advice shall include:
    a. A summary of any escalation factors used in the determination.
    b. Likely output at 41°C which will take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors.
2. The Power Station costs shall be determined with specific reference to the use of actual project-related data or current market information and shall take into account the specific conditions under which the Power Station will be developed. This may include direct reference to:
    a. Existing power stations or power station projects under development, in Australia and more particularly Western Australia.
    b. Cost information obtained from the market sources such as supplier and manufacturer for recent and relevant actual cost reference.
    c. Worldwide demand for gas turbine engines for power stations.
    d. The engineering, design and construction, environment and cost factors in Western Australia.
    e. The level of economic activity at the state, national and international level.
3. Development of the Power Station costs shall include components for the gas turbine engines, and all Balance of Plant costs that would normally be applicable to such a Power Station based *GT Pro* breakup. This will include the following items:
    a. Equipment;
    b. Civil Works;
    c. Mechanical Works;
    d. Electrical Works;
    e. Buildings and Structures;
    f. Engineering and Plant start-up (includes commissioning); and
    g. Miscellaneous and other costs.
4. The Power Station upon which the Maximum Reserve Capacity Price shall be based will:
    a. be representative of an industry standard liquid-fuelled Open Cycle Gas Turbine (OCGT) power station;
    b. have a nominal nameplate capacity of 160 MW prior to the addition of any inlet cooling system;
    c. operate on distillate as its fuel source with distillate storage for 14 hours of continuous operation;

d. have a capacity factor of 2%;
e. include low Nitrous Oxide (NO_x) burners or associated technologies (e.g. water injection) as considered suitable and required to demonstrate good practice in power station development;
f. include an inlet air cooling system where this would be cost effective; and
g. Include water receival and storage capability to support 14 hours of continuous operation.

C.1.2 Fixed operating and maintenance costs

1. Fixed Operating and Maintenance (O&M) costs for the Power Station inclusive of the following items:
    a. Plant operator labour;
    b. OCGT substation (connection to tie line);
    c. Rates;
    d. Market fee;
    e. Balance of plant;
    f. Consent (EPA annual charges emission tests);
    g. Legal;
    h. Corporate overhead;
    i. Travel;
    j. Subcontractors;
    k. Engineering support;
    l. Security;
    m. Electrical (including Control & Instrumentation); and
    n. Fire.
2. Fixed Operating and Maintenance (O&M) costs for the associated transmission connection work (i.e. the overhead transmission line and the connection switchyard) inclusive of the following items:
    a. Cost of labour for routine maintenance;
    b. Cost of machine/plant/tool hire for routine maintenance; and
    c. Overhead (management, administration, operation etc).
3. It is noted that SKM will not provide an estimate of annual asset insurance cost required to insure the replacement of power station capital equipment, infrastructure, and associated transmission connection work.
4. The estimated fixed O&M cost will not allow for defect or asset replacement during the lifetime of the assets.
5. SKM notes that the maintenance cost for an asset is incurred periodically according to its maintenance routines. Since this routine is different for different asset classes, SKM will smooth these period costs evenly over the life of the power station, transmission line and connection switchyard and convert into an annualised fixed O&M costs.
6. To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component shall be presented for each 5 year period up to 60 years.

7. Fixed O&M costs must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using the following escalation factors which shall be provided as part of the advice provided under scope C.1.2 and applied to relevant components within the Fixed O&M cost:
   a. Generation O&M Cost escalation factor for Generation O&M costs;
   b. a Labour cost escalation factor for transmission and switchyard O&M costs; and
   c. CPI for fixed network access and/or ongoing charges determined with regard to the forecasts of the Australian Bureau of Statistics and, beyond the period of any such forecasts, the mid-point of the ABS's target range of inflation.

C.1.3 Fixed fuel cost

2. Fixed fuel costs for the liquid fuel storage and handling facilities including:
   a. A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund suitable for 14 hours operation.
      1. Facilities to receive fuel from road tankers.
      2. All associated pipework, pumping and control equipment.
3. The estimate will be based on the following assumptions:
   a. Land is available for use and all appropriate permits and approvals for both the power station and the use of liquid fuel have been received.
   b. Any costing components that may be time-varying in nature must be disclosed by the IMO. Such components might be the cost of the liquid fuel, which will vary over time and as a function of exchange rates etc.
4. SKM notes that the costing must only reflect fixed costs associated with the fixed fuel cost (FFC) component and must include an allowance to initially supply fuel sufficient to allow for the Power Station to operate for 14 hours at maximum capacity.
5. Fixed fuel costs (FFC) must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where costs have been determined at a different date, those costs must be escalated using the annual CPI cost escalation factor.

C.1.4 Legal, financing, insurance, approvals, other costs and contingencies (margin M)

1. The IMO shall engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:
   a. legal costs associated with the design and construction of the power station;
   b. financing costs associated with equity raising;

c. insurance costs associated with the project development phase;
d. approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;
e. other costs reasonably incurred in the design and management of the power station construction; and
f. Contingency costs.

Total Transmission Cost Estimate for the Maximum Reserve Capacity Price for 2015/16

8 October 2012

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1 Introduction

This document provides the calculation of the Total Transmission Costs (TTC) in accordance with section 2.4 of the IMO Market Procedure: Maximum Reserve Capacity Price Version 5 for 2015/16.

The IMO Market Procedure for the determination of the Maximum Reserve Capacity Price (MRCP) requires Western Power to use actual capital contributions from users to calculate a single estimate of Total Transmission Costs. However, Western Power must reiterate that any future capital contributions for new connections must be assessed on an individual basis under the Contributions Policy as approved by the ERA and in no way relate to the transmission component of the MRCP.

It should be noted that Western Power is obligated under relevant legislation to treat commercially sensitive customer information on a confidential basis. Individual customer capital contributions which are now required to be used to calculate the TTC can not be publically disclosed by Western Power. The IMO has requested Western Power use the spreadsheet they provide which has been verified by the IMOs' auditor to implement the requirements of the new procedure. Western Power has collated customer capital contributions and included them in the spreadsheet provided by the IMO to calculate an average Total Transmission Cost per MW.

The new procedure also requires that Western Power appoint a suitable auditor to review the application of the process in step 2.4.1.

2 MRCP Procedure

2.1 Methodology

In accordance with the IMO market procedure, Western Power must provide an estimate of the TTC using the methodology specified.

In summary, the estimated TTC is largely based on a weighted average over 5 years of the capital contributions (either paid historically or expected to be paid to Western Power under Access Offers and Western Power's Contribution Policy as approved by the ERA) only for generators that are capable of being gas or liquid fuelled.

The calculation must exclude any facility where:

- the significant driver for the location of the facility is the access to source energy (fuel or renewable) or the need to embed the generation with a load (electrical or heat); or
- the facility is connected on a shared distribution feeder; or
- the capital contribution does not relate to a significant increase in the Declared Sent Out Capacity associated with the facility.

Where no capital contributions have been paid in a particular year an estimate of shallow transmission connection costs only for the works required to connect a relevant generator to the shared transmission is used.

Western Power must estimate the shallow transmission connection costs for the works required to connect a relevant generator to the shared transmission network in accordance with section 2.4.2 of the procedure.

The estimate of shallow connection costs is also used to determine the basis of escalation of network infrastructure costs where relevant, and it is calculated as an average change over 5 years in the estimates calculated consistent with section 2.4.2.

For more details of methodology, please see the new revised procedure on the IMO web site.

http://www.imowa.com.au/f711,1679263/PC_2011_06_Market_Procedure_for_Maximum_Reserve_Capacity_Price_FINAL_clean.pdf

2.2 Western Powers' Contributions Policy and NFIT

Actual transmission connection costs are governed by the Access Code 2004, the New Facilities Investment Test (NFIT), and Western Powers' Access Arrangement, and Contributions Policy approved by the ERA.

In accordance with section 5.2 of Western Powers' contributions policy, a contribution payable by a customer for any works is calculated by:

- determining the appropriate portion of any of the *forecast costs* of the *works* which do not meet the *new facilities investment test,*
- adding any applicable costs related to ensuring *technical rules* compliance for the network,
- adding the full *costs* of any *works* to provide *connection assets*, and the full amount of any *non-capital costs* that Western Power incurs acting efficiently in accordance with *good electricity industry practice*,

- acting as a *reasonable and prudent person*, Western Power may determine that the costs be allocated to the applicant and other users based on the relative use of the *works (in accordance with section 5.4),*
- deducting the amount likely to be recovered in the form of *new revenue* gained from providing *covered services* to the *applicant*, as calculated over the reasonable time, at the *contributions rate of return*.

Western Power believes that recent connections have been somewhat opportunistic and the capital contributions have been consequently low (relatively speaking).

These lower costs are now required to be included in the MRCP calculation. Western Power expects the new procedure will consequently result in a decrease in the transmission cost component of the MRCP. However, it should be noted that future capital contributions which may be required from users in no way relate to the transmission component of the MRCP. A capital contribution required from any new user will be assessed individually and depend on the amount of network investment that may or may not pass the New Facilities Investment Test which may ultimately be determined by the ERA.

2.3 Shallow Connection Costs

For the purposes outlined in step 2.4.1 of the market procedure, Western Power must also estimate the shallow transmission connection costs for the works required to connect a relevant generator to the shared transmission network.

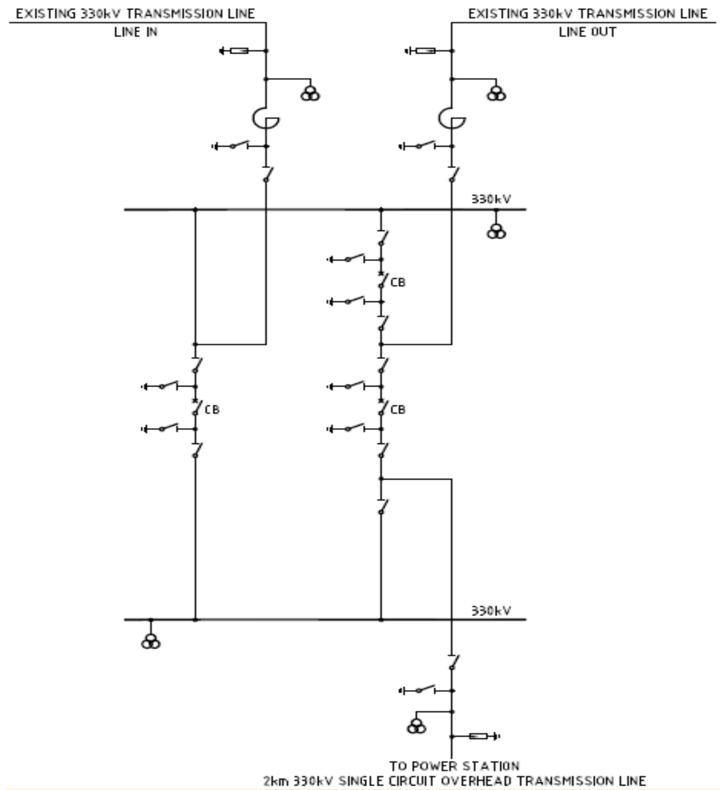
In summary, estimates in accordance with section 2.4.2 of the procedure are required for the costs for the following:

- a substation,
- 2 km of overhead line to the power station, and
- an overhead line easement.

Each of these cost components are discussed below.

2.3.1 Substation

In accordance with the Market Procedure the Transmission Connection Cost Estimate should include the cost of a generic three breaker mesh substation configured in a breaker and a half arrangement. The connection of the substation into the transmission line should be turn-in, turn-out and will be based on the most economical (i.e. least cost) solution. The typical three-switch mesh 330 kV substation configuration which has been used recently in the SWIS has been assumed as shown in the single line diagram below.



The table below lists the estimated costs of a typical new substation. It should be noted that the estimate does not include the cost of the land nor does it take into account any site specific details.

Total Substation Cost

Description	Cost
330kV Breaker & Half, 3xCircuit Breakers, 3xGantry, 2xCircuits	$ 4,240,000
Site Works - Terminal Station 1 Yard (3 Bays)	$2,810,000
Terminal Relay Room	$2,370,000
TOTAL	$9,420,000

2.3.2 *Overhead Line to Power Station*

In accordance with the MRCP Procedure the Transmission Connection Cost Estimate should include the cost for 2 km of 330 kV overhead single circuit line to the power station that will have one road crossing. It shall be assumed that the transmission connection to the Power Station will be located on 50% flat - 50% undulating land, 50% rural - 50% urban location and there will be no unforeseen environmental or civil costs associated with the development.

The table below shows the estimated costs of the 2km transmission line connection.

Connection Transmission Line Costs

Description	Cost
Connection Assets (Two kilometres of single circuit steel towers to connect the generator)	$8,007,652

2.3.3 Easement for Overhead Line

In accordance with the MRCP Procedure, the cost of an easement for the 2km overhead line has been provided by the IMO in accordance with section 2.4.2(h) of the new procedure and is $5,146,959[1].

2.3.4 Total Shallow Connection Cost

The Total Shallow connection costs calculated in accordance with section 2.4.2 of the procedure is $22,574,611[2].

Total Transmission Connection Cost Estimate

Description	Cost
Substation	$9,420,000
Transmission line	$8,007,652
Line easement	$5,146,959
TOTAL	**$22,574,611**

The Substation and Transmission Line costs have decreased by 18% and 4% respectively compared to last year as a result of both internal efficiency improvements in Western Power and significant reductions in market rates for contract services, materials, plant and equipment. In particular, external market fluctuations attributed to economic down turn has seen contractual rates reduce in many areas, particularly civil works, and the latest quotations for steel procurement associated with Transmission Lines have provided reductions in cost compared to last year.

The Line easement costs provided to Western Power by the IMO have reduced by 4% due to a reduction in the valuation from the Valuer General's Office.

[1] Typographical error corrected. Previous number was $4,758,600.
[2] Typographical error corrected. Previous number was $22,186,252.

3 Total Transmission Costs

Western Power is required to provide an estimate of the Total Transmission Costs in accordance with section 2.4 of the IMO Market Procedure: Maximum Reserve Capacity Price Version 5. In accordance with the procedure, Western Power has sought agreement with the IMO regarding which generators should be included in the calculation of the TTC, and has collated all relevant information including confidential capital contribution data and estimates of shallow connection costs for the current and previous years. The TTC has been calculated in accordance with the specified methodology which is summarised in section 2.1 of this report.

3.1 Total Transmission Costs

The Total Transmission Costs calculated in accordance the Market Procedure is $115,124 / MW.

3.2 Escalation Factor for Network Infrastructure

The escalation factor for network infrastructure calculated in accordance with section 2.4.1(d) of the Market Procedure is -2.91%.

3.3 Audit Report

The new procedure requires that Western Power appoint a suitable auditor to review the application of the process in step 2.4.1, and the auditor's report is attached in Appendix A.

Appendix A. Auditor's Report

ERNST & YOUNG

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To the Directors of Electricity Networks Corporation

Independent Assurance Practitioner's Review Report

Report on the Total Transmission Cost Estimate for the Maximum Reserve Capacity Price for 2015/16

We have reviewed the process adopted by Electricity Networks Corporation ("Western Power") to estimate the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 as required by the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5.

Respective Responsibilities

Management of Western Power are responsible for the preparation of the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 in accordance with the requirements of the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5.

Our responsibility is to express a conclusion on the process adopted by Western Power in determining the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 as required by the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5. Our review has been conducted in accordance with Auditing Standard ASAE 3000 *Assurance Engagements other than Audits or Reviews of Historical Financial information*, to provide limited assurance that Western Power has followed the process to determine the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 as required by the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5. Our procedures consisted of making enquiries of persons responsible for the preparation of the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 Report and applying analytical and other review procedures. These procedures have been undertaken to form a conclusion that nothing has come to our attention that causes us to believe that Western Power has not, in all material respects, undertaken a process to determine the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 that is in accordance with the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5.

Use of Report

This review report was prepared for Western Power in accordance with the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5. We disclaim any assumption of responsibility for any reliance on this report to any persons or users other than Western Power, or for any purpose other than that for which it was prepared.

Inherent Limitations

Because of the inherent limitations of any process, it is possible that fraud, error or non compliance with a process may occur and not be detected. A review is not designed to detect all instances of non compliance with the requirements of the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5 as it generally comprises of making enquiries of persons responsible for the preparation of the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 Report and applying analytical and other review procedures. The review conclusion expressed in this report has been formed on the above basis.

RK:KE:ElectricityNetworks:006

ERNST & YOUNG

Independence

In conducting our review, we have complied with the independence requirements of Australian professional accounting bodies.

Conclusion

Based on our review, which is not an audit, nothing has come to our attention that causes us to believe that Electricity Networks Corporation has not, in all material respects, adopted a process to estimate the Total Transmission Costs for the Maximum Reserve Capacity Price for 2015/16 that is in accordance with the Independent Market Operator's Market Procedure: Maximum Reserve Capacity Price Version 5.

Ernst & Young

Robert A Kirkby
Partner
Perth
8 October 2012

RK:KE:ElectricityNetworks:006

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Greg Ruthven - Manager System Capacity
IMO
Governor Stirling Tower
197 St Georges Tce
Perth WA 6000

2 January 2013 *WP04558*

Dear Greg,

2015/16 MCRP Construction Insurance Cost

SKM has considered the construction insurance costs given as a part of margin M in its report to you on the 2015/16 MRCP costs.

In light of the changes to insurance premiums generally and with regard to the likelihood that premiums may not reduce significantly in the new few years we have amended the allowance from 0.4% to 0.5%.

The remainder of our report is unchanged.

Yours sincerely

Tim Johnson
Leader Strategic Consulting, Power WA & NT
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Cc Johan van Niekerk, IMO
Jaden Williamson, SKM

Mr Allan Dawson
Chief Executive Officer
Independent Market Operator
Level 3, Governor Stirling Tower
197 St Georges Terrace
Perth WA 6000

15 October, 2012

Dear Mr. Dawson,

Re: Review of debt and equity related issues within the WACC used in the Maximum Reserve Capacity Price

You have engaged PricewaterhouseCoopers (PwC) to undertake a review of debt and equity related issues within the weighted average cost of capital (WACC) used in the Maximum Reserve Capacity Price (MRCP). As the Independent Market Operator (IMO) in Western Australia, you have received a number of comments from stakeholders that have suggested that components of the previous methodology used by the IMO to estimate a WACC for this purpose did not reflect real world costs. In response, you have commissioned this review to examine the issues raised in the submissions.

Our Scope

The Scope of Works that you provided to us comprised three parts, which can be summarised in the following questions:

Issue 1: How is the risk free rate being applied to estimate the cost of equity?

Issue 2: What alternative methods are being applied to estimate the debt risk premium?

Issue 3: Is the value of gamma being amended from 0.5 to 0.25?

We note from our discussions and correspondence with the staff of IMO, that in preparing the WACC for use in the Maximum Reserve Capacity Price, the IMO does not consider itself to be a leader in the field of WACC. As such, in reviewing methodologies for determining each of the WACC parameters you have instructed us to:

- Only consider methodologies that have been used by one or more Australian regulators, particularly in WA if possible, whose decisions are subject to merit review;[1] and

- Can be determined from publicly available data.

You have also directed us not to provide our own opinions about the correctness of regulatory decisions, and not to refer to current practice in parallel fields (such as corporate valuations).

[1] For example, this requirement of IMO meant that we could not consider the decisions of the Independent Price and Regulatory Tribunal (IPART), or of the Queensland Competition Authority (QCA).

In this letter, based on these directions, we have provided a summary of the IMO's past practice for each of the issues listed above, and a summary based on our review of Australian regulatory practice in jurisdictions whose decisions are reviewable. Further discussion of Australian regulatory practice (within the constraints set out above) in relation to each of the issues is provided in the Appendix.

Issue 1: How is the risk free rate being applied to estimate the cost of equity?

The IMO's previous practice

The previous methodology applied by the IMO estimated the WACC by reference to the annualised yield on Commonwealth Government bonds, where this rate reflects the average over a short, recent period. A number of stakeholders have suggested to the IMO that its previous WACC methodology failed to reflect the 'real world' costs of equity owing to the fact that the yields on Commonwealth bonds are currently at historical lows.

Summary of current Australian regulatory practice where decisions are potentially subject to merit review

Despite a significant fall in the spot risk free rate over the last year, the AER and ERA have continued to apply the spot risk free rate (rather than an estimate of the long term risk free rate):

- The Australian Energy Regulator (AER) has made a number of regulatory pricing decisions in the past year, and has maintained a position of incorporating the observed risk free rate into its WACC calculations, which have resulted in historically low estimates of the cost of equity and hence regulated rates of return for energy distribution and transmission businesses.

- This approach has been justified by the AER on grounds that it maintains an objective and consistent position over time.

- The Economic Regulation Authority of Western Australia (ERA) has followed the approach of the AER.

- A formal appeal on this issue in the context of current market conditions has not been brought before the Australian Competition Tribunal (ACT), and has therefore not been tested in that forum.

We caution, however, that this position is contentious – refer to the Appendix for more detail.

Issue 2: What alternative methods are being applied to estimate the debt risk premium?

The IMO's previous practice

The debt risk premium (DRP) estimated by the IMO has previously been derived from the yields on Australian corporate bonds with a BBB equivalent credit rating. Several stakeholders have suggested to the IMO that it is unlikely that a developer would raise debt finance in the bond market, and would be more likely to obtain bank funding.

Under its previous approach the IMO assumed a BBB credit rating and estimated the debt risk premium for 10 year debt based on extrapolation of the 7 year Bloomberg BBB fair value curve. Extrapolation was undertaken by referencing the historical increment in the debt risk premium in the Bloomberg AAA rated fair value curve from 7 to 10 years. It has been suggested that bank debt is a more appropriate benchmark for the costs faced by a developer of a stand-alone generator.

Summary of current Australian regulatory practice where decisions are potentially subject to merit review

Among Australian regulators whose decisions are subject to merit review there is currently a significant degree of variety and instability in the methodologies used to estimate the debt risk premium.

ERA

The ERA applies what it terms the 'bond yield approach' to estimate a debt risk premium. In its 28 February 2011 Final Decision on WA Gas Networks Pty Ltd (ATCO), the ERA applied this approach to estimate a debt risk premium.[2] The ERA established a set of criteria by which it chose bonds based on:

- A credit rating of BBB-/BBB/BBB+ by Standard and Poor's;
- Time to maturity of 2 years or longer;
- Bonds issued in Australia by Australian entities and denominated in Australian dollars;
- Inclusion of both fixed bonds and floating bonds; and
- Inclusion of both Bullet and Callable/Putable redemptions.

The ERA's method was appealed to the Australian Competition Tribunal (the Tribunal), which substantially upheld the ERA's method, with the only modification required being to alter its weighting method as it gave inordinate weight to certain observations.

AER

The AER's recent final decisions on Powerlink, Aurora Energy,and Roma to Brisbane Pipeline decisions, and its SPI Networks (Gas) Pty Ltd draft decision have broadly accepted the extrapolated Bloomberg curve methodologies that were proposed by these businesses.[3] This methodology is to estimate the 7 year BBB+ debt risk premium based on the Bloomberg BBB 7 year fair value curve, and then to extrapolate this value to 10 based on:

- In the case of Powerlink and Aurora Energy - the average annual increment of the debt risk premium observed for paired bonds (i.e. bonds with different terms to maturity issued by the same firm), where the terms to maturity are approximately equal to 7 and 10 years;

[2] Economic Regulation Authority (Western Australia) (28 February, 2011), *Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, pp. 75-92.
[3] AER (2012), pp.154-155.

- In the case of the Roma to Brisbane Pipeline – the increment in the Bloomberg AAA fair value curve using its last historical spread to the Commonwealth Government Securities (CGS) yield; and

- In the case of SPI Networks (Gas) Pty Ltd – the average annual increment of the debt risk premium observed for paired bonds (with some slight modifications to the paired bonds proposed by SPI Networks (Gas) Pty Ltd).[4]

However, in its recent decisions on the Roma to Brisbane pipeline and SPI Networks (Gas) Pty Ltd, the AER has noted the Tribunal's decision in the ATCO case, and has expressed its concern that the Bloomberg methodology is providing cost of debt estimates that are too high. As a result the AER is undertaking an internal review of the issue.

Summary with respect to estimation of the debt risk premium

In summary, there is no single debt cost estimation methodology that is widely applied by Australian regulators whose decisions are subject to merit review.

Of the two contrasting estimation methodologies outlined above, the approach applied by the ERA would provide a lower cost of debt relative to the AER's method. When last applied by the ERA, the cost of debt was estimated for a term to maturity of near 5 years due to its application of a 2 year cut-off rule for the inclusion of bonds.

With respect to the issue of assessing the cost of bank debt, we note that as far as we are aware, no Australian regulator has applied a cost of debt estimate that is based on a measure of the cost of bank debt. Instead, Australian regulators have assumed that the cost of bonds is reflective of the cost of the firm's entire debt portfolio, which will generally be comprised of a mix of debt and bonds.

Issue 3: Is the value of gamma being amended from 0.5 to 0.25?

IMO's previous practice:

Previously the IMO was applying a gamma assumption of 0.5, which was consistent with the practice of the majority of regulators. However, a recent Australian Competition Tribunal (ACT) decision has reduced gamma from 0.5 to 0.25. The IMO is seeking advice on whether this change is being undertaken by Australian regulators whose decisions are subject to merit review.

Summary of current Australian regulatory practice where decisions are potentially subject to merit review

In its recent decision on gamma the Tribunal oversaw a detailed and rigorous process of debate about gamma that was informed by a comprehensive empirical analysis, and required the AER to adopt this value. The AER has adopted a gamma value of 0.25 in all of its subsequent decisions. The ERA applied a gamma value of 0.25 in its recent decision on the Western Power Network.[5].

4 AER (September, 2012), p.37.

5 ERA (29 March, 2012), *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, p.170.

*   *   *

Yours sincerely,

Principal

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Appendix –Summaries of Australian regulatory practice where the regulator is subject to review

Issue 1: How is the risk free rate being applied to estimate the cost of equity?

Background

The IMO's stakeholders have correctly observed that 10 year Commonwealth Government Securities (CGS), which have traditionally been taken as proxies for the risk free rate that is applied in the Capital Asset Pricing Model (CAPM), are currently at extremely low levels compared to the historical average. Over the period from 2000 up to the commencement of the global financial crisis in 2008, the yield 10 year CGS was approximately 5.5 per cent.[6] However, soon after the collapse of the Lehman's Brothers Bank in September 2008, CGS yields dropped below 4 per cent, and after recovering for a time, have in the past 12 months dropped to new lows of approximately 3 per cent. During these two periods there has been a 'flight to quality' which has resulted in capital being attracted to Australian CGS due to our relatively strong Australian dollar and our political stability.

In regulatory matters, a number of businesses have argued that this almost unprecedented drop in the risk free rate has implications for the estimation of the cost of equity in Australia. The contention is that, if the current interest rates on 10 year CGS are mechanically applied to the CAPM formula this would predict that the cost of equity for the average Australian business should have fallen by approximately 300 basis points since the start of the global financial crisis.

Professor Robert Officer, a renowned expert on WACC issues, described the risk for error when the MRP and risk free rate are not set over the same time period:[7]

> "If MRP is set at an 'average or normal level' which is representative of a long run mean or expected value over the long term and Rft is at a low level, such as exists at the moment, this will under-estimate the return to equity E(Re,t) and penalize the regulatory entity, and conversely when Rf is at a 'high level'. Therefore, setting the parameters on the basis of different time periods when one is set at the current time may lead to greater error than if they were both set on the basis of the current same or 'normal' time period even though this is not representative of the current period."

Professor Officer describes three outcomes for the cost of equity based on the way the MRP and risk free rate are estimated.[8]

> "Noting the comments above, in estimating the parameters of the CAPM and having regard to the evidence of current MRP and Rf, there are three possible outcomes:

6 Two dates that are often used as approximate starts for the global financial crisis are 1 June 2007 (which was just before issues with US subprime mortgages first emerged) and 1 September 2008 (which was just prior to the collapse of the Lehman Brothers Bank). The average rates on 10 year CGS between 1 January 2000 and 1 June 2007 and 1 September 2008 were 5.67 per cent and 5.76 per cent, respectively.

7 R.R.Officer, (16 February, 2009), *Expert Report prepared in respect of certain matters arising from the AER'sNew South Wales Draft Distribution Determination 2009-10 to 2013-14*, Prepared for Energy Australia, para.25.

8 R.R.Officer, (16 February, 2009), Expert Report prepared in respect of certain matters arising from the AER'sNew South Wales Draft Distribution Determination 2009-10 to 2013-14, Prepared for EnergyAustralia, para.33.

a) if the MRP and the Rf were both estimated in current market conditions, then the estimated cost of equity would reflect the likely cost of equity over the next regulatory period and is likely to be much higher than the long term average …;

b) if the MRP and the Rf are both estimated over the a long term, or reflect, a more "normal" period, then they will result in a cost of equity that is comparable to the long run cost of equity, which is believed to be below the current required return to equity …;

c) if the MRP is based on a long term average and the Rf is set reflecting current conditions where Rf are at abnormally low levels then the resulting cost of equity will be set below average or normal market conditions and well below what is likely to be required in the current market for returns on equity …"

Professor Officer also noted:[9]

"Regarding my conclusion in paragraph (c) above, I do not consider that such an estimate is likely to provide an unbiased value for the current cost of capital for a company. I do not think that current market conditions are requiring a below average cost of capital, in fact, quite the reverse when we look at the discount being required for rights and similar attempts at raising equity capital."

There is considerable support in the theoretical and empirical finance literature for the proposition that the cost of equity does not move one-for-one with government interest rates. For example, Lettau and Ludvigson (2001) found that equity risk premiums tended to move in the opposite direction to the de-trended government bond rate.[10] The AER's consultant, Professor Kevin Davis (2011), recently also noted that 'there is nothing in the [CAPM] model which implies that the parameters of the model will be the same in different time periods.'[11]

Position of the AER

In its recent final decision on Aurora Energy the AER articulated its view that the current historically depressed risk free rate is a valid, market-determined parameter that should not be adjusted in the CAPM framework. The AER is of the view that at 'times of uncertainty, investors are prepared to accept a lower yield on relatively safe assets,' and that furthermore:[12]

An alternative explanation might be that CGS are currently 'over priced', in the sense that the price of CGS exceeds its fair value, and therefore the yield is 'artificially low'. For the AER to make such a conclusion, the AER would, effectively, be saying that it has better information than the market or that it 'knows better' than the many traders in the market whose interactions set the price of CGS. The AER considers there is not a reasonable basis to draw such a conclusion on the evidence before it.

The AER considered that the CGS market 'remains liquid and efficiently priced', and therefore the methodology of applying market-determined CGS yields as the proxy for the risk free rate is objective and unbiased. Furthermore, the AER rejected the view expressed by Professor Officer that it is not appropriate to match a short term risk free rate with a long term market risk premium:[13]

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9 R.R.Officer, (16 February, 2009), Expert Report prepared in respect of certain matters arising from the AER'sNew South Wales Draft Distribution Determination 2009-10 to 2013-14, Prepared for EnergyAustralia, para.34.

10 Lettau, Martin, and Sydney Ludvigson (2001), 'Consumption, Aggregate Wealth and Expected Stock Returns,' *Journal of Finance*, Vol. 56 (3), pp. 815-849.

11 Davis, Kevin, (January, 2011), *Cost of Equity Issues*: A Report for the AER, p.4.

12 AER (2012), *Distribution determination – Aurora 2012-13 to 2016-17: Cost of capital*, p.133.

13 AER (2012), p. 136.

> As discussed above, the AER considers it is incorrect to characterise the method for calculating these WACC parameters as a long term historical MRP coupled with a short term risk free rate. The risk free rate is not 'short term'. The risk free rate and MRP are both reflective of a forward looking return over the next 10 years. However, there are different considerations and evidence available for each parameter. The approach adopted by the AER is therefore internally consistent.

The AER also commented on the approach IPART used in its SDP decision, noting that IPART's decisions are not completely comparable to the AER's:[14]

> IPART's approach involves adopting a range for some WACC parameters. This approach results in a range for the overall rate of return. IPART then exercises its judgement in choosing an appropriate overall WACC from within this range. The AER notes that IPART often chooses a point estimate which differs from the midpoint of the derived range.

The AER then pointed that the AER's approach arises from the constraints that are imposed on it by the National Electricity Rules (NER) and Statement of Regulatory Intent (SRI) requirements, which necessitate a point estimate approach. In conclusion the AER considered that:

> While the approaches of the AER and IPART differ, they are both internally consistent over time. Consistency is important to achieve unbiased outcomes. The AER considers that it is inappropriate for it to make an upward adjustment in the current framework. To do so on an ad hoc basis creates the potential for arbitrariness and introduces subjectivity, which results in the potential for biased regulatory outcomes.

These views were re-iterated by the AER in its contemporaneous Roma to Brisbane Pipeline decision.[15] In its March 2012 draft decision on the Western Power Network, the ERA also applied a 'spot' risk free rate.[16]

Issue 2: What alternative methods are being applied to estimate the debt risk premium?

In this section we review the debt risk premium estimation methodologieses that have been taken by Australian regulators whose decisions are reviewable. Hence we have summarised the approaches used by the AER and the ERA.

Economic Regulation Authority of Western Australia

The Economic Regulation Authority of Western Australia (ERA) set out its new approach to measurement of the debt risk premium in a Discussion Paper published in December 2010. The Discussion Paper raised a concern that the Bloomberg 7 year BBB fair value curve was no longer representative of observed Australian bond yields. The ERA presented two charts, one for a period before (10 November 2005 to 9 October 2007), and a period after (19 August 2009 to 31 October 2010) the worst of the global financial crisis. The ERA concluded that the use of 'Bloomberg is problematic because it could add significant inaccuracy in and inconsistency across regulatory decisions.'[17]

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14 AER (2012), p. 137.

15 AER (April, 2012), *APT Petroleum Pipeline Pty Ltd – Access arrangement draft decision Roma to Brisbane Pipeline 2012-13 to 2016-17*, pp. 130-131.

16 ERA (29 March, 2012), *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, pp. 157-160.

17 Economic Regulation Authority (Western Australia) (1 December, 2010), pp. 4 and 7.

On 28 February, 2011, in its Final Decision on WA Gas Networks Pty Ltd (ATCO), the ERA applied its 'bond yield approach' to estimate a debt risk premium.[18] The ERA established a set of criteria by which it chose bonds based on:

- A credit rating of BBB-/BBB/BBB+ by Standard and Poor's;
- Time to maturity of 2 years or longer;
- Bonds issued in Australia by Australian entities and denominated in Australian dollars;
- Inclusion of both fixed bonds and floating bonds; and
- Inclusion of both Bullet and Callable/Putable redemptions.

The ERA's method was appealed to the Australian Competition Tribunal (the Tribunal), which substantially upheld the ERA's method, with the only modification required being to alter its weighting method as it gave inordinate weight to certain observations.

The ERA's approach was founded on a concern that in the Australian capital market at that time (December 2010), most bonds had a maturity term well below 10 years. As a result, it identified a trade-off between:[19]

- Consistency between the debt risk premium and other WACC parameters, such as the nominal risk free rate and expected inflation, in terms of a 10-year term; and
- How well the estimates of the debt risk premium are commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services ('market relevance').

The ERA considered that greater weight should be placed on market relevance rather than on consistency with other WACC parameters. In other words, the considered it to be more important to have a large sample of bonds over a range of maturities than to only take account of a smaller number of bonds with a maturity close to 10 years, or even to attempt to adjust the "raw" debt risk premium in order to target a 10 year figure (the average term in the ERA sample was 5.2 years).

Our view is that the ERA's method would be subject to a number of criticisms or potential modifications if applied today. We note that there is substantial evidence that the debt risk premium increases with term, and a number of reports in regulatory proceedings have demonstrated how statistical procedures could be used to adjust the debt risk premium element to be more consistent with the target term. In addition, new data sources have become in common use since the ERA's decision (namely many additional floating rate bonds) as well as additional data points (i.e., corporate bonds on issue).

Australian Energy Regulator (AER)

In recent years the AER has frequently changed its approach to estimating the cost of debt:

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18 Economic Regulation Authority (Western Australia) (28 February, 2011), *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, pp. 75-92.

19 Economic Regulation Authority (Western Australia) (1 December, 2010), p. 8.

- Choosing between the extrapolated Bloomberg and CBASpectrum curves - Up to September 2010, Bloomberg and CBASpectrum provided competing fair value curves, and the AER applied a methodology to assess which curve lay closer to the observed bond yields. Unfortunately the number of bonds was very small (5).

- Averaging the Bloomberg curve and the APA bond - CBASpectrum discontinued publication of its fair value curve from mid-August, 2010, which caused the AER to change its approach to debt premium estimation. The Australian Pipeline Trust (APA) had recently issued a 10 year BBB rated bond. The AER concluded that the debt risk premium should be calculated as a weighted average of the yield on the APA bond and the extrapolated Bloomberg curve, albeit with the weights being determined by judgement, and varying between decisions. This method was appealed against to the Tribunal, which in its Envestra decision, concluded the following:[20]

  > Envestra provided to the AER strong evidence in support of the EBV, in particular by its response to the May 23 letter. The view of Dr Hird of CEG was that that material did not demonstrate any basis for the substitution of an alternative estimate for the EBV. As noted, the AER itself accepted the relevance of the EBV. Whilst the Tribunal accepts that the AER properly considered the reliability of the EBV, it has reached the view on the available material that there is no reason shown from the available material why the use of the EBV should not be adopted in this particular matter. There is no viable alternative methodology at present, other than making a decision on all the material. The observations of the Tribunal in ActewAGL at [74]-[78] suggest that, on the existing material, it is appropriate to vary the decision in the manner indicated.

  In light of this and other Tribunal decisions, the AER discontinued its hybrid approach of using a weighted average of the APA bond and the Bloomberg curve.

- A simple average of debt risk premiums –The AER applied a new approach in Powerlink's and Aurora Energy's 2012-13 to 2016-17 draft revenue determinations.[21] It estimated the debt risk premium for a BBB+ rated 10 year bond by calculating a simple average of the debt risk premiums for bonds with a term to maturity between 7 and 13 years and a given set of characteristics.[22]

- Extrapolated Bloomberg curve – The AER's recent final decisions on Powerlink, Aurora Energy and the Roma to Brisbane Pipeline accepted the extrapolated Bloomberg curve methodologies that were proposed by these businesses.[23] This methodology is to estimate the 7 year BBB+ debt risk premium based on the Bloomberg BBB 7 year fair value curve, and then to extrapolate this value to 10 based on:

  – In the case of Powerlink and Aurora Energy - the average annual increment of the debt risk premium observed for paired bonds (i.e. bonds with different terms to maturity issued by the same firm), where the terms to maturity are approximately equal to 7 and 10 years; and

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20 Application by Envestra Limited (No 2) [2012] ACompT 3 (11 January 2012), para. 123.

21 AER (November, 2011), *Draft decision, Powerlink Transmission determination, 2012-13 to 2016-17*; and AER (November, 2011), *Draft Distribution Determination, Aurora Energy Pty Ltd 2012-13 to 2016-17*.

22 The Bloomberg BGN value is yield that is derived on the basis of the individual securities industry feeds to Bloomberg (i.e. a combination of the contributor opinions about the yield), while the BVAL value is Bloomberg's opinion of the yield.

23 AER (2012), pp.154-155.

– In the case of the Roma to Brisbane Pipeline – the increment in the Bloomberg AAA fair value curve using its last historical spread to the CGS yield.

In its most recent decision, which relates to SPI Networks (Gas) Pty Ltd, the AER has again applied the average annual increment of the debt risk premium observed for paired bonds (with some slight modifications to the paired bonds proposed by SPI Networks (Gas) Pty Ltd.[24] However, AER took note of the Tribunal's decision in the ATCO case as follows:[25]

> Consistent with the AER's observations previously, the AER considers that the Bloomberg fair value curve continues to provide DRP estimates which are higher than other potential approaches (such as the ERA's approach). The Bloomberg fair value curve also provides estimates which are high in comparison to recent bond issuances from firms with similar characteristics to the benchmark firm. For these reasons, the AER has commenced an internal review into alternatives to the Bloomberg fair value curve.

Issue 3: Is the value of gamma being amended from 0.5 to 0.25?

Regulatory practice:

Gamma refers to the value of distributed imputation credits. It is an important parameter since it is used in determining the compensation that the benchmark firm requires for tax, in recognition that the firm's investors can benefit from imputation credits to offset personal tax, or receive cash if their tax rate is below the statutory corporate rate. It has been a contentious issue in the regulatory sphere, notwithstanding that until 2009 the vast majority of Australian regulators applied a gamma assumption of 0.5.

It is widely acknowledged that the best way to represent gamma, is as the product of the distribution ratio (F); and the 'utilisation rate' (theta or θ), i.e.:

$$\gamma = F \times \theta$$

Where,

- F, the distribution ratio, is defined as the value of imputation credits distributed by a firm as a proportion of the value of all the imputation credits generated by the firm in the period; and

- Theta, or θ, is defined as the value of imputation credits once they have been distributed to investors as a proportion of their face value.

In May 2009 the Australian Energy Regulator undertook a review of WACC parameters for the electricity transmission and distribution sectors, and determined a gamma value of 0.65. This value was derived by assuming a distribution ratio of 1.0, on the grounds that it is consistent with the assumptions underpinning the Officer WACC framework, and a utilisation rate (theta) of 0.65, which was based on an average of:[26]

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24 AER (September, 2012), p.37.

25 AER (September, 2012), *Access arrangement draft decision – SPI Networks (Gas) Pty Ltd 2013-17, Part 1*, p. 37.

26 AER (May, 2009), *Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters.*

- A dividend drop-off study conducted by Beggs and Skeels, which indicated a theta value of 0.57;[27] and

- A study by Handley and Maheswaran, which used statistics from the Australian Taxation Office showing that during the period 2001 to 2004 the redemption rate of imputation credits was 0.81.[28]

In May 2010 the AER made a decision that applied the gamma value of 0.65 to the calculation of revenues of Energex Limited, Ergon Energy Corporation Limited and ETSA Utilities.[29] These decisions were appealed to the Australian Competition Tribunal (the Tribunal), which decided to address the common gamma issue under a joint application. In October, 2010 the Tribunal found that an error of fact had been made by the AER with respect to the distribution ratio, as the AER had now accepted that the distribution ratio of 71 per cent derived from Hathaway and Officer (2004), was in fact the long term distribution ratio.

With respect to theta, the Tribunal also found error in the AER's approach, since it had erroneously taken a simple average of point estimates. The Tribunal requested a report that:[30]

- proposes an approach that correctly uses tax statistics studies and dividend drop-off studies;

- reviews dividend drop-off studies from as many sources as possible to see whether confident use can be made of any of them; and

- if possible, provides results from a newly-commissioned dividend drop-off study that is "state of the art".

To achieve this, the Tribunal required that the new dividend drop-off study should be undertaken by SFG employing a methodology that is agreed between the AER and SFG. This resulted in a number of new submissions and new evidence being provided by the parties:[31]

- SFG (21 March, 2011), *Dividend Drop-Off Estimate of Theta*;

- The Securities Industry Research Centre (SORCA) Limited (7 March 2011), *Report to the AER – Response to questions related to the estimation and theory of theta.*

- AER (April, 2011), *The value of imputation credits* (report to the AER);

- Submissions from the applicants in response to the AER's report, including supporting evidence;

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27 Beggs, D.J. and C.L. Skeels (2006), Market Arbitrage of Cash Dividends and Franking Credits, *The Economic Record*, Vol. 82 (258), pp. 239-252.

28 Handley, J and K. Maheswaran, (March, 2008) 'A Measure of the Efficacy of the Australian Imputation Tax System, *Economic Record*, Vol. 84, Issue 264, pp. 82-94.

29 AER (4 May, 2010), *ETSA Utilities – Distribution determination 2010-11 to 2014-15*; AER (4 May, 2010), *Energex – Distribution determination 2010-11 to 2014-15*; AER (May, 2010), *Ergon Energy – Distribution determination 2010-11 to 2014-15.*

30 Application by Energex Limited (No 2)[2010] ACompT7 (13 October 2010), para. 146.

31 Application by Energex Limited (Gamma) (No 5)[2011]A CompT(12 May 2011), para. 8.

- R.R. Officer (18 April, 2011), *Expert Report prepared in respect of certain matters arising from the AER's Merit review – Determination of Gamma* – prepared for ETSA Utilities, Energex and Ergon Energy.

- SFG (18, April, 2011), *Dividend Drop-Off Estimate of Theta – Additional Estimates based on comments in the AER Report*;

- Diamond, N. And R Brooks (19 April, 2011), *A review of SFG's Dividend Drop-off Study*; and

- SFG (21, April, 2011), *Dividend Drop-Off Estimate of Theta – Additional Estimates based on comments in the AER Report,* referred to by the Tribunal as 'SFG's further supplementary report').

SFG's March 2011 report proposed a theta estimate of 0.35, and in reviewing the new information before it the Tribunal was satisfied that the procedures used to select and filter the data were appropriate and unlikely to give rise to any significant bias. Having accepted a theta value of 0.35, and having previously accepted a distribution ratio of 0.70, the Tribunal determined that the value of gamma is 0.25.[32] However, in making its decision the Tribunal noted that 'estimation of a parameter such as gamma is necessarily, and desirably, an ongoing intellectual and empirical endeavour.' In other words, while on the basis of the best available evidence the Tribunal had concluded that a gamma of 0.25 is appropriate, it was not precluding future analysis of this parameter, which could see it change.

Since the Tribunal's decision, the AER has applied a gamma of 0.25 in all of its decisions, and the ERA has also followed this approach, concluding its consideration of this matter in its recent draft decision on Western Power as follows:[33]

> Based on an estimate of the payout ratio of imputation credits of 70 per cent, together with an estimate of theta of 0.35, the Authority concludes that a reasonable value of gamma, for the purpose of the Authority's draft decision on Western Power's proposed Access Arrangement, is 0.25 (or 25 per cent). The estimate of gamma of 0.25 is consistent with the Tribunal's recent decision on gamma in *Energex Limited*.

[32] Application by Energex Limited (Gamma) (No 5)[2011]A CompT(12 May 2011), para. 42.

[33] ERA (29 March, 2012), p.170.

Johan van Niekerk
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Independent Market Operator
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18 December 2012

Dear Johan

Update of debt risk premium using the ERA's debt yield methodology

The purpose of this report is to update the debt risk premium estimates that were set out in our report to the Independent Market Operator (IMO) dated 7 December 2012. That report set out estimates of the debt risk premium that would arise from applying the Economic Regulation Authority of Western Australia's (ERA) "bond yield" methodology. This report provides new debt risk premium estimates for a new averaging period, namely the 20 business days ending with 30 November 2012, inclusive ("updated period"). Other than updating the results for updated period, the method we applied is identical that applied in our earlier report. Regard should be had to that earlier report for a full description of the method we applied and for our related observations.

Results

The tables set out below replicate (and have identical numbering to) the tables that were set out in our earlier report for the updated period.

As shown in Table 1 below, we have derived a debt risk premium of 269 basis points for the updated period when undertaking a strict application of the methodology the ERA applied in the final revised ATCO decision.[1] If we again modify the ERA methodology to restrict the sample of bonds to only BBB rated bonds, we estimate a debt risk premium of 271 bonds. Finally, if we again retain the ERA methodology's original sample, but modify the term to maturity cut-off to three years, we estimate a debt risk premium of 274 basis points.

More detailed tables of the results obtained by applying the ERA's 'bond yield' methodology can be found in Appendix A, which again replicates Appendix A from our earlier report for the updated period.

[1] Economic Regulation Authority (25 June, 2012), *Revised decision pursuant to rule 6.4(4) of the National Gas Rules giving effect to the Economic Regulation Authority's proposed access arrangement revisions for the Mid-West and South-West Gas Distribution System, Revised by reason of and pursuant to orders of the Australian Competition Tribunal made on 8 June 2012*,

Table 1 – Summary of debt risk premium estimates using the ERA's bond yield methodology – 20 business days to 30 November 2012 (basis points)

Sample	Average term to maturity	Average debt risk premium	Weighted average debt risk premium	Comment
Two year cut-off: **BBB – 13 bonds** **BBB+ – 5 bonds**	4.50	269	269	Strict application of ERA approach in its ATCO final revised decision
Two year cut-off: **BBB – 13 bonds**	4.50	269	271	Constrained to include only BBB rated bonds
Three year cut-off: **BBB – 10 bonds** **BBB+ – 4 bonds**	5.07	278	274	Cut-off increased to 3 years to provide more consistency with other WACC parameters

Source: PwC's analysis of the ERA's debt yield methodology, Bloomberg

If you wish to discuss further the contents of this note, please do not hesitate to call me on the number provided below.

Yours sincerely

Jeff Balchin
Principal
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Appendix A – Detailed debt risk premium estimates

Table 2 – Debt risk premium estimates applying the ERA's debt yield methodology for 20 business days to 30 November 2012 (2 year cut-off, BBB and BBB+ bonds)

Bond	S&P Credit rating	Issue size ($m)	Maturity date	Term to maturity	Weighting	DRP (bps)	Contributed DRP(bps)
APT Pipeline	BBB	300	22/07/2020	7.67	0.14	301	44
Brisbane Airport	BBB	200	9/07/2019	6.63	0.08	270	23
Holcim Finance	BBB	200	4/04/2019	6.37	0.08	253	20
Caltex Australia	BBB+	150	23/11/2018	6.01	0.06	243	14
Dexus finance	BBB+	120	10/09/2018	5.81	0.04	252	11
Sydney Airport	BBB	100	6/07/2018	5.63	0.04	286	10
Crown group	BBB	300	18/07/2017	4.66	0.09	245	22
Holcim Finance	BBB	250	18/07/2017	4.66	0.07	230	17
Dexus finance	BBB+	210	21/04/2017	4.42	0.06	224	13
United energy distribution	BBB	265	11/04/2017	4.39	0.07	286	21
New terminal financing	BBB	100	20/09/2016	3.83	0.02	293	7
Mirvac Group	BBB	225	16/09/2016	3.82	0.05	319	17
DBCT Finance	BBB+	150	9/06/2016	3.55	0.03	364	12
Goodman	BBB	175	19/05/2016	3.49	0.04	330	13
Santos Finance	BBB+	100	23/09/2015	2.84	0.02	253	5
Sydney Airport	BBB	175	6/07/2015	2.63	0.03	237	7
Holcim Finance	BBB	250	27/03/2015	2.35	0.04	192	7
Mirvac Group	BBB	200	15/03/2015	2.32	0.03	260	8
Simple Average				**4.50**		**269**	
Weighted Average							**269**

Source: PwC's analysis of the ERA's debt yield methodology, Bloomberg

Table 3 – Debt risk premium estimates applying the ERA's debt yield methodology for 20 business days to 30 November 2012 (2 year cut-off, BBB bonds only)

Bond	S&P Credit rating	Issue size ($m)	Maturity date	Term to maturity	Weighting	DRP (bps)	Contributed DRP(bps)
APT Pipeline	BBB	300	22/07/2020	7.67	0.18	301	55
Brisbane Airport	BBB	200	9/07/2019	6.63	0.11	270	29
Holcim Finance	BBB	200	4/04/2019	6.37	0.10	253	26
Sydney Airport	BBB	100	6/07/2018	5.63	0.04	286	13
Crown Group	BBB	300	18/07/2017	4.66	0.11	245	27
Holcim Finance	BBB	250	18/07/2017	4.66	0.09	230	21
United Energy Distribution	BBB	265	11/04/2017	4.39	0.09	286	27
New Terminal Financing	BBB	100	20/09/2016	3.83	0.03	293	9
Mirvac Group	BBB	225	16/09/2016	3.82	0.07	319	22
Goodman	BBB	175	19/05/2016	3.49	0.05	330	16
Sydney Airport	BBB	175	6/07/2015	2.63	0.04	237	9
Holcim Finance	BBB	250	27/03/2015	2.35	0.05	192	9
Mirvac Group	BBB	200	15/03/2015	2.32	0.04	260	10
Simple Average				**4.50**		**269**	
Weighted Average							**271**

Source: PwC's analysis of the ERA's debt yield methodology, Bloomberg

Table 4 – Debt risk premium estimates applying the ERA's debt yield methodology for 20 business days to 30 November 2012 (3 year cut-off with BBB and BBB+ bonds)

Bond	S&P Credit rating	Issue size ($m)	Maturity date	Term to maturity	Weighting	DRP (bps)	Contributed DRP(bps)
APT Pipeline	BBB	300	22/07/2020	7.67	0.16	301	49
Brisbane Airport	BBB	200	9/07/2019	6.63	0.09	270	25
Holcim Finance	BBB	200	4/04/2019	6.37	0.09	253	23
Caltex Australia	BBB+	150	23/11/2018	6.01	0.06	243	16
Dexus Finance	BBB+	120	10/09/2018	5.81	0.05	252	12
Sydney Airport	BBB	100	6/07/2018	5.63	0.04	286	11
Crown Group	BBB	300	18/07/2017	4.66	0.10	245	24
Holcim Finance	BBB	250	18/07/2017	4.66	0.08	230	19
Dexus Finance	BBB+	210	21/04/2017	4.42	0.07	224	15
United Energy Distribution	BBB	265	11/04/2017	4.39	0.08	286	24
New Terminal Financing	BBB	100	20/09/2016	3.83	0.03	293	8
Mirvac Group	BBB	225	16/09/2016	3.82	0.06	319	19
DBCT Finance	BBB+	150	9/06/2016	3.55	0.04	364	14
Goodman	BBB	175	19/05/2016	3.49	0.04	330	14
Simple Average				**5.07**		**278**	
Weighted Average							**274**

Source: PwC's analysis of the ERA's debt yield methodology, Bloomberg

alintaenergy

19 December 2012

Mr Greg Ruthven
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Dear Greg

DRAFT REPORT: MAXIMUM RESERVE CAPACITY PRICE FOR 2015/16 CAPACITY YEAR

Alinta Energy (Alinta) appreciates the opportunity to provide a submission to the Independent Market Operator (IMO) on its Draft Report: Maximum Reserve Capacity Price (MRCP) for the 2015/16 Capacity Year.

This submission is intended to supplement the views put forward in January 2012 by Alinta on the Draft Report: MRCP for the 2014/15. In particular, Alinta continues to consider that a 'significant economic event' has occurred since PricewaterhouseCoopers (PwC) finalised its advice to the IMO and MRCP Working Group (MRCPWG) in February 2011 on the Weighted Average Cost of Capital (WACC) methodology. If anything, the evidence of a significant economic event is best illustrated by the recent market observations related to actual returns across a broad spectrum of securities. In particular there is a significant divergence between the rates for risky and non-risky assets in Australia:

- riskless securities such as government bonds have an artificially low rate as a result of foreign investors demand outstripping current supply; while
- risky securities such as bank debt have experienced an increasing cost of financing, as is evidence by the increased spread between bank borrowing and lending costs.

Consequently, Alinta continues to request the IMO to exercise its discretion under the Market Procedure for the determination of the Maximum Reserve Capacity Price (the Market Procedure) and re-examine the appropriateness of the prescribed five year values for the market risk premium (MRP) and equity beta used to calculate the WACC.

Alinta also requests the IMO to:

- reconsider whether the risk free rate of return being applied in the WACC continues to be appropriate given that government bond rates have been artificially reduced; and
- utilise bonds with a credit rating of only BBB in applying the ERA's bond-yield to ensure that the riskiness of investing in generation assets in the WEM is appropriately reflected.

Further details of Alinta's concerns are discussed in more detail in this submission.

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Background

Purpose of the MRCP

The primary purpose of the MRCP is to cap the price that may be paid by the IMO for capacity should a capacity shortfall arise. The MRCP reflects the estimate cost of providing new generation capacity in a future Capacity Year, and is calculated through a bottom-up evaluation of the forecast cost of constructing a new 160 MW Open Cycle Gas Turbine to enter the WEM during the relevant Capacity Year.

The MRCP is also used to derive the Reserve Capacity Price (RCP) for the WEM, an administered price that may be paid for capacity that is voluntarily made available to the IMO. Due to concerns around the inability of the RCP to adjust quickly to market conditions, a review of the formula used to determine the RCP has been undertaken by the Reserve Capacity Mechanism Working Group (RCMWG). Alinta anticipates that the IMO will progress a Rule Change Proposal to implement a proposed revision to the formula for setting the RCP during early 2013. Any resultant Amending Rules should be subject to a transition period given that the changed method may lead to material financial impacts.

Revised Market Procedure

The Market Procedure details the method and process to be followed by the IMO when annually determining the MRCP. Under the Market Rules the IMO is required to review the Market Procedure at least once in every five years. To this effect the IMO established the MRCPWG in May 2010 to consider, assess and develop necessary changes to the Market Procedure.

To assist the MRCPWG in its deliberations, PwC was engaged by the IMO to broadly review the appropriateness of the WACC parameters, including considering any changes in the regulatory environment that may require revisions to the methodology used to calculate the WACC.

The resultant revised Market Procedure commenced on 24 October 2011 and was applied by the IMO in setting the MRCP for the 2014/15 Capacity Year. Application of the revised methodology (which was not subject to a transition period) along with year-on-year variations in the input parameters, primarily for the WACC, resulted in a reduction in the MRCP of 31% (to $166,100) from the value determined for the 2013/14 Capacity Year of $240,600.

Proposed MRCP for the 2015/16 Capacity Year

The IMO proposes a MRCP for the 2015/16 Capacity Year of $157,500 per MW per year[1], a reduction of 3.9% from the 2014/15 MRCP. The IMO notes that the most significant changes have been with respect to:

- Power Station Costs (3.7% lower) as a result of falling steel and copper prices coupled with the appreciation of the Australian dollar against the Euro;
- Fixed Fuel Costs (122% higher) as a result of Sinclair Knight Merz's (SKM) review of the estimate with the benefit of recent project experience in Western Australia; and

[1] Note that this value is inclusive of the proposed change in the gamma variable used in the WACC from 0.5 to 0.25 which has been proposed under PC_2012_08. The proposed revision will ensure consistency with Australian regulators during the past 18 months and is supported by Alinta.

- WACC (reduction from 6.83% to 6.03%) driven by a further deterioration in government bond yields and use of the bond yield approach developed by the ERA for determining the debt risk premium.

In its submission on the MRCP for the 2014/15 Capacity Year, Alinta raised a number of concerns with the year-on-year variations being indicative of a “significant economic event” having occurred since PwC provided advice on the WACC methodology to the MRCPWG in February 2011.

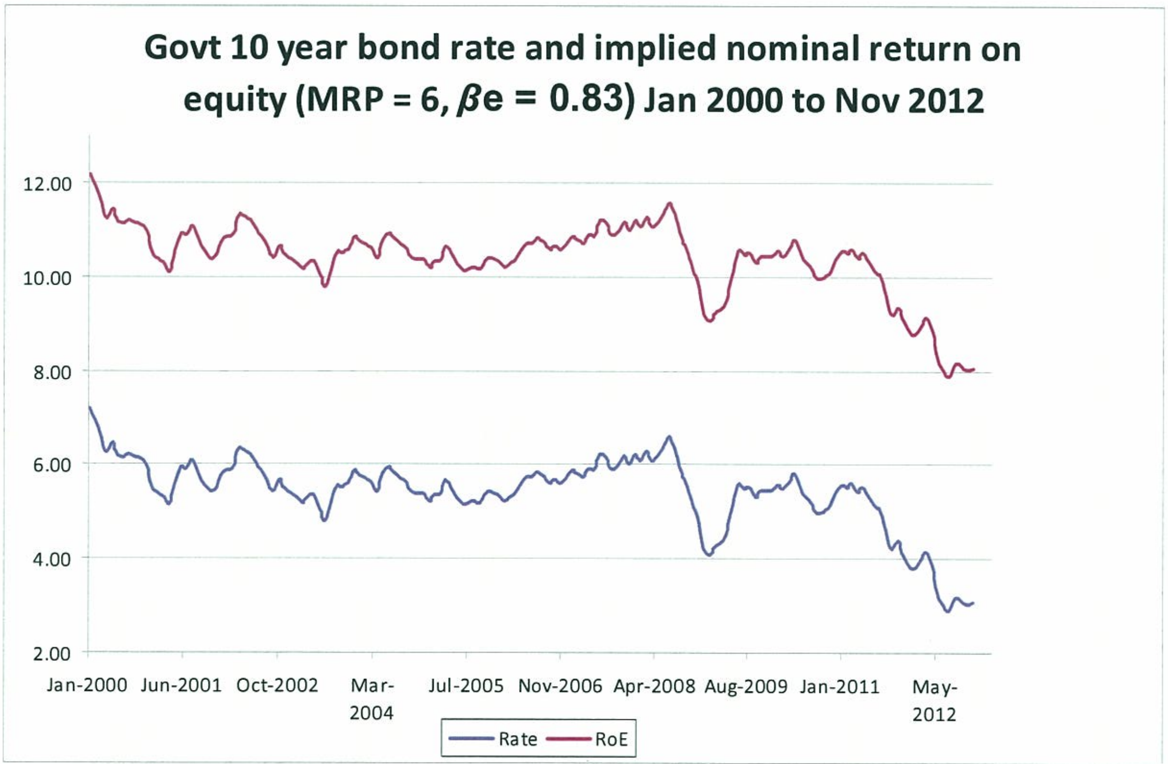
Evidence during 2012 continues to support this observation and is presented below. Additionally detail of Alinta’s other concerns around the cost of equity and debt risk premium applied in the WACC methodology are also provided.

Issue 1. Low cost of equity used is not consistent with rational investor’s expectations

The Market Procedure requires the cost of equity to be calculated using the CAPM, which multiples the Market Risk Premium (MRP) by the equity beta, with the resultant product being added to the risk free rate.

In determining the proposed value of the MRCP for the 2015/16 Capacity Year, a nominal return on equity of only 8.11% has been used in accordance with the requirements of the Market Procedure. This represents a reduction of approximately 9% from the value of 8.9% that was applied in setting the MRCP for the 2014/15 Capacity Year. Further details of the continuing downward trend in the implied nominal return on equity, as determined in accordance with the Market Procedure, are reflected in Figure 1 below. Note that as the MRP and equity beta values are prescribed in the Market Procedure the predominant cause of the reduction has been from reductions in the rates for ten year commonwealth government bonds.

Figure 1:



Alinta does not consider that a rational investor would develop generation assets in the WEM for a return on equity of less than 12% and therefore questions the appropriateness of the values used in determining the return on equity. In particular, Alinta is concerned that the prescribed values applied for the MRP and equity beta are no longer applicable given recent stock market and electricity market experiences. Likewise Alinta considers that the risk free rate of return applied by the IMO in undertaking this review has been artificially deflated as a result of foreign investors placing downward pricing pressure on 10 year government bonds. These issues are explored in more depth in the following sections.

Market Risk Premium

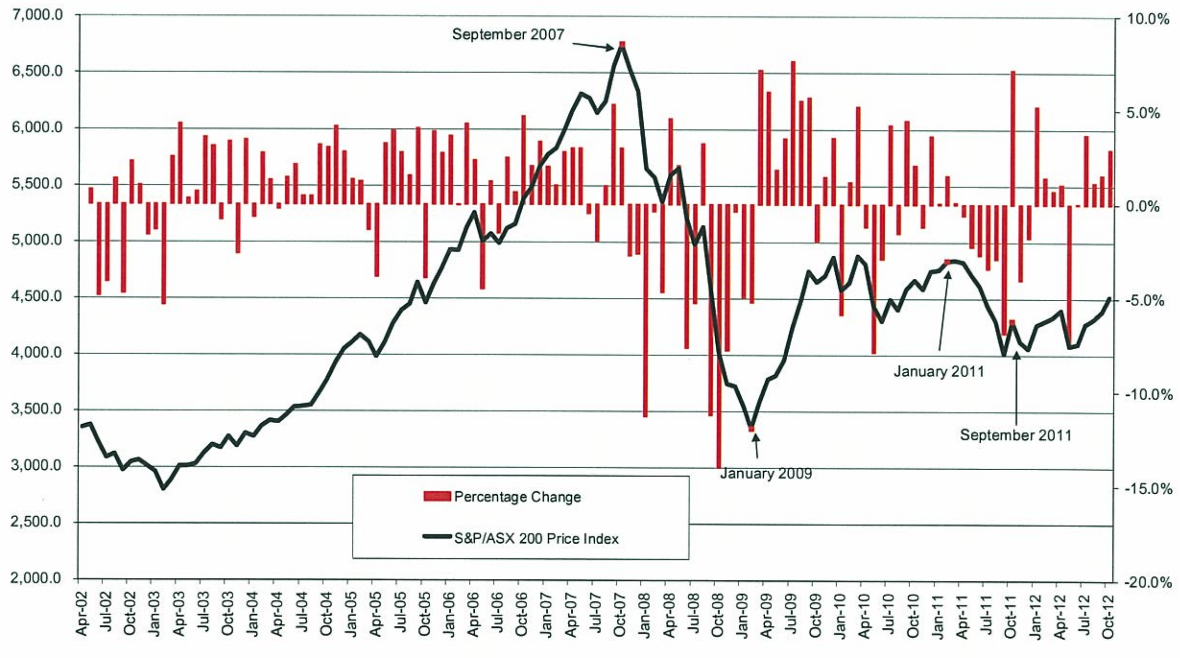
The MRP is the expected return over the risk free rate (compensation) that investors would require in order to accept average market risk.

In its final report for the MRCPWG, PwC (p. 24) recommended:

> *"...a value for the MRP of 6.0 percent taking into account an emerging regulatory position for a revision to a long-standing position of adopting a MRP of 6.0 percent after contemplating a higher value of 6.5 percent for a period during and after the global financial crisis".*

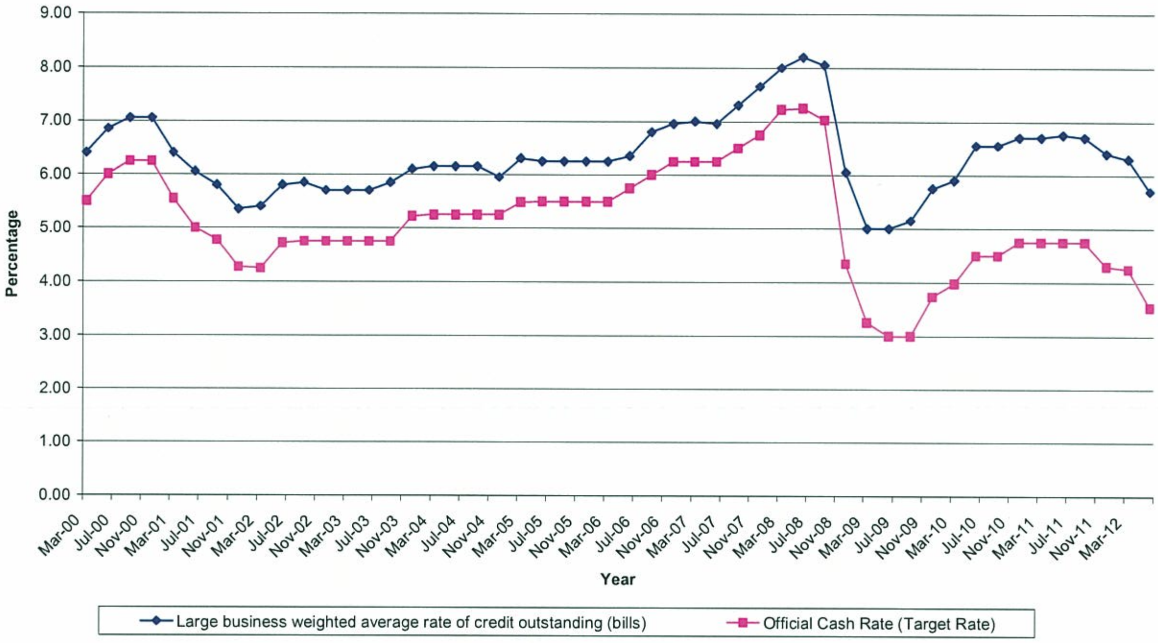
In its previous submission on the 2014/15 MRCP determination, Alinta raised concerns that given the increase in stock market volatility since the finalisation of PwC's report a review of the MRP was required. This volatile behaviour has continued during 2012 as illustrated by Figure 2 below.

Figure 2: ASX All Ordinaries Price Index



Supporting the preposition that a "significant economic event" has occurred, Alinta also notes that there has been an increase in the divergence between the lending and borrowing rates of banks since March 2009. This is illustrated in Figure 3 below.

Figure 3: Comparison of Bank Borrowing and Lending Rates from March 2000 - June 2012



Given PwC's comments (noted above), it reasonably follows that investors expected MRP will also have increased from 6% given the occurrence of a "significant economic event" resulting in greater levels of investment uncertainty. Alinta notes that other electricity regulators have applied higher MRP's in recent years. In particular, following its 2009 review of the WACC parameters the Australian Energy Regulator (AER) has been applying a MRP of 6.5% to transmission and distribution network determinations as reflected in its guideline document. This includes for recent draft determinations such as for ElectraNet and Murraylink[2]. Alinta notes that the AER adopted a value of 6.5% "having regard to the desirability of certainty and stability".

Alinta recommends that in light of continued market evidence of a "significant economic event" having occurred and given that recent regulatory precedent of the AER, the IMO should consider adopt a MRP of 6.5%, as is applied by other regulators would be appropriate for determining the MRCP.

Equity Beta

The equity beta measures the riskiness of the business relative to the overall market. It reflects the business's exposure to non-diversifiable risk. The equity beta value was reviewed in 2011 by PwC (who proposed a lower value on 0.77 along with a gearing of 35%[3]) and is based on 28 Australian and internationally listed generation businesses.

During the past four years electricity generators have experienced far more volatility than the market as a whole. This is evidenced by the recent significant reductions in electricity demand in the eastern states that have occurred in isolation from a reduction in economic growth. Likewise in Western

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[2] Alinta notes that under rule 6A.2.3 of the National Electricity Rules guidelines are not mandatory and the AER can apply a different MRP value if there are reasons for departing from those values reflected in the guidelines.

[3] The MRCPWG decided to not adopt the recommendation to amend the gearing ratio or equity beta as proposed by PwC. Refer to Meeting 7: http://www.imowa.com.au/MRCPWG

Australia actual demand for energy has not been as high as was originally predicted given that a number of large new loads that were assumed in the Statement of Opportunities did not eventuate. Other factors resulting in volatility in the WEM include:

- significant variations in the Reserve Capacity Price that have created significant concerns for investors around expected returns on both new and existing generation assets;
- the impact of a Demand Side Management (DSM) on the Reserve Capacity Price, i.e. significant entry of DSM into the market over the last few years has contributed to an oversupply of capacity;
- significant cost to Market Generators of operating in the new Balancing and Load Following markets;
- increases in the penetration of renewable energy technologies have resulted in reduced overnight prices which have on occasions caused base load facilities to turn off over night and have changed requirements for Ancillary Services;
- uncertainty created by the Rule Change Process;
- lack of investment by the private sector in recent times in the WEM except in joint venture with Government, e.g. Vinalco, Mumbida windfarm, Greenlough River Solar Farm.

Given the volatility in the operating environment for electricity generation assets in Australia and specifically Western Australia, Alinta considers that the current value for the equity beta is inappropriate and resulting in a "non-real world" WACC outcome. Even at the assumed gearing levels, an equity beta of less than one does not adequately reflect the volatility in expected returns and therefore the relative riskiness faced by a standalone generator in Western Australia. An equity beta of less than one may be appropriate for an existing state owned base load generator however the risk profile is significantly greater for a privately funded new entrant electricity generator[4]. As the MRCP based on the development of a new 160MW Open Cycle Gas Turbine, Alinta considers it is appropriate to assume the higher risk profile would apply.

While the overall impact on the nominal return on equity is as a result of a combination of parameters, including the risk free rate of return and MRP (both discussed in this submission), Alinta considers that the IMO should engage an economic consultant to re-examine the equity beta given that it does not adequately reflect the riskiness of investment in a generator in the WEM.

Risk Free Rate of Return

The risk free rate represents the rate of return on an asset with zero default risk and is a key component of both the cost of equity (through the CAPM) and cost of debt.

In its submission on the MRCP for the 2014/15 Capacity Year, Alinta noted evidence of a "flight to quality" stemming from the continued economic uncertainty and share market instability leading to greater demand, and reduced yields, on Commonwealth Government bonds given the perception of Australia as a low risk economy.

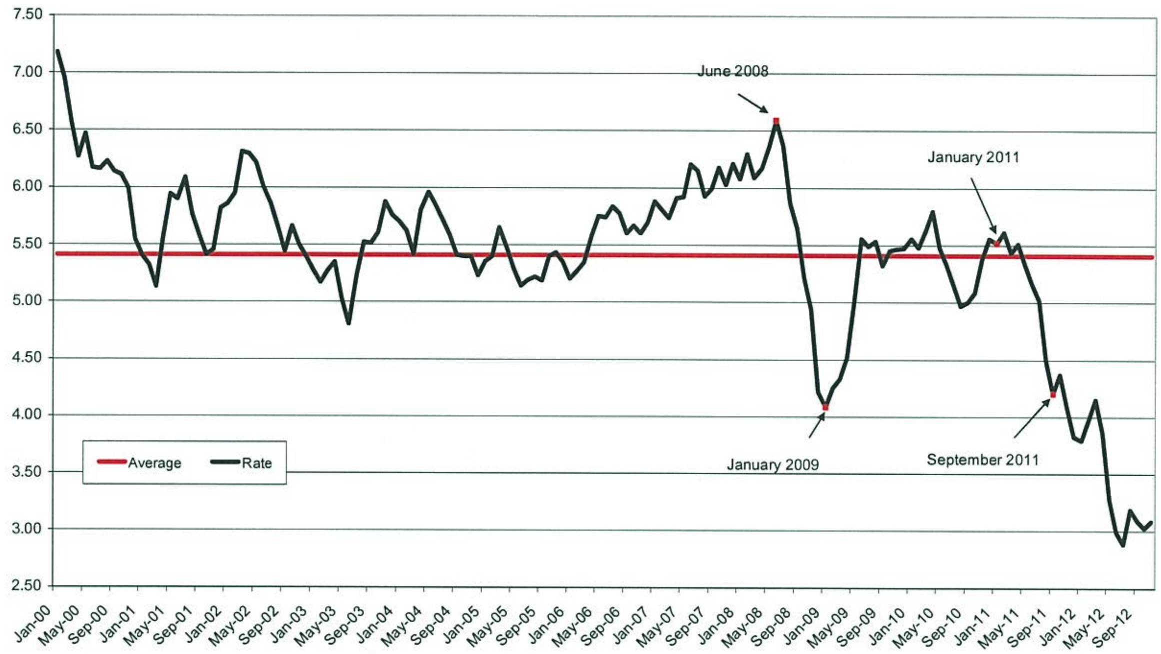
The Commonwealth Government bond rate has continued to fall during 2012 as is illustrated in Figure 4 below. An analysis of the data indicates the following:

[4] Refer to section 7.3 of the Energy Market Authorities Review of the Parameters for setting the vesting price for the period 1 January 2010 to 31 December 2010:
http://www.ema.gov.sg/media/com_consultations/attachments/1252902213LRMC_consultation_report__26_Jun_09_.pdf

The long-run average monthly 10-year government bond rate, the "risk free rate", over the period January 2000 to November 2012 was 5.4 percent. This average has been further depressed by the low bond yield values that have occurred since December 2011[5] and is lower than the bond rate in January 2011 when PwC finalised its advice to the MRPCWG.

- The actual monthly 10-year government bond rate was 2.89 percent in July 2012, though has risen slightly to 3.09 in November 2012. These values are the lowest in the data series.

Figure 4: RBA Published Monthly 10-Year Government Bond Rate



The continued reductions in the government bond yields have resulted in a reduction in the nominal risk free rate of return applied in determining the WACC by 20%, from 3.92% to 3.13%, since determining the MRCP for the 2014/15 Capacity Year.

In its Final Report to the MRCPWG (pp 20-21), PwC noted that:

> *"...during the global financial crisis the convenience yield (measured as the difference between the yield on 10 year Commonwealth Government Securities and the 10 year Credit Default Swap) rose to 120 basis points, which was 76 basis points higher than the historical relationship measured over the period from 1991 to 2010. In these circumstances,* ***an adjustment to the risk free rate was potentially justified****. However, the current differential between the yield on 10 year Commonwealth Government Securities and the 10 year Swap yield is now close to the historically average differential (Figure 4.1). As such, it appears that the distortion of the market for Government bonds during the period of the global financial crisis has diminished."* (emphasis added).

Alinta is concerned that the application of the risk free rate based on the current abnormally low yield on ten year Commonwealth Government bonds does not reflect the true risk free rate but rather is inappropriately depressed compared with its long run average value. Additionally, Alinta notes that once committed the development of generation assets are naturally long term investment decisions

[5] In January 2012 when Alinta prepared its submission on the MRCP for the 2014/15 Capacity Year the long-run average was 5.56 percent.

(30-40 years). The development of an asset such as a power station is very costly and requires significant certainty and stability of returns. Investors traditionally look to the capacity price to provide this certainty given the restrictions on bidding in the energy market (i.e. price caps and SRMC bidding requirements).

Alinta continues to request that the IMO seek advice from an economic consultant to confirm whether:

- global structural imbalances have created an excess demand for Commonwealth Government Bonds which have subdued their observed price, thereby justifying an adjustment to the risk free rate; and
- longer term, the observed yield on government bond remains an acceptable proxy measure of the risk free rate.

Issue 2. Uncertainty around appropriateness of use of the ERA's bond yield approach in determining the Debt Risk Premium for a generation asset.

In determining the WACC for a Capacity Year, the Market Procedure requires that the nominal return on debt be calculated as the risk free rate plus a debt risk premium plus an allowance for debt issuance costs. The implicit assumption is that the developer of the new generation facility would issue bonds into the corporate bond market to finance the debt component of the project.

The IMO is required under the Market Procedure to determine the methodology to estimate the debt risk premium, which in the opinion of the IMO is consistent with current Australian accepted regulatory practice. Following the Australian Competition Tribunal's decision to uphold the bond-yield approach applied by the ERA in its final decision on WAGN[6], the IMO now considers that this approach is accepted regulatory practice and therefore has adopted it for determining the WACC.

Alinta supports the use of the ERA's bond yield approach for the purposes of determining a WACC for an electricity generation business. However, Alinta considers that using an investment grade rating of BBB+ is inappropriate for generators in the WEM. The debt levels and riskiness of servicing that debt for electricity generators is significantly greater than for network generation businesses. Further, during the past few years' significant financial problems have been experienced by a number of the Market Generators in the WEM. Given recent experience Alinta questions whether any generators in the WEM (and more broadly Australia) currently have a BBB+ investment grade rating (or even a BBB investment grade rating). Alinta requests the IMO to undertake an assessment of the ratings of independently owned electricity generators in Australia to confirm an appropriate investment grade to be used for the purposes of the ERA's bond yield approach.

Conclusion

Given the evidence that has emerged since the finalisation of PwC's advice in February 2011, Alinta considers that it is clear that a significant economic event has occurred. This provides the basis for the IMO to exercise its discretion to determine alternative values for the MRP and equity beta values in the Market Procedure. Subsequently, Alinta requests that the IMO initiate another review of the Market Procedure to consider the values for these parameters.

It is important that the MRCP accurately reflects the complete and total cost and risks (regulatory, policy, economic and commercial) of developing a 160MW OCGT in the WEM given the MRCP's

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[6] Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution System.

important and vital role in setting the administered price where no capacity auction is held[7]. The issues highlighted by Alinta in this submission regarding the accuracy of the WACC have subsequent impacts on the accuracy of the MRCP. Alinta therefore recommends that the IMO:

- undertake a review of the MRP and equity beta prescribed in the Market Procedure.
- engage a suitable consultant to:
    - determine whether structural imbalances have artificially reduced the price of government bonds which means that an adjustment to the risk free rate is required; and
    - consider whether longer term the use of the 10-year yield on government bonds remains the best indicator; and
- only use bonds with a BBB rating when applying the ERA's bond yield approach.

Should you require any further information relating to Alinta's submission, please do not hesitate to contact me on 08 9486 3762. Alternatively you may contact Fiona Edmonds, Wholesale Regulation Manager on 08 9486 3009.

Yours sincerely

Michelle Shepherd
General Manager Regulatory and Government Affairs

[7] While Alinta acknowledges that the primary role of the MRCP is to set a cap for the Reserve Capacity Auction an auction has not occurred since market start.

Community Electricity

Submission on the Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year

Standing

Community Electricity is a member of the Independent Market Operator's Market Advisory Committee as a Market Customer representative. It was also a member of the former Maximum Reserve Capacity Working Group which framed the Market Procedure: Maximum Reserve Capacity.

Community has separately submitted support of Procedure Change Proposal PC_2012_08 which proposes to reset the value of the imputation credit constant to 0.25 from the current setting of 0.5.

Community is also a member of the Economic Regulation Authority's Technical Rules Committee.

Submission

Community supports the Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year.

We expressly support:

- The manner in which the Market Procedure: Maximum Reserve Capacity Price has been applied;
- Application of the ERA's Bond Yield approach to determining the Debt Risk Premium component of the Weighted Average Cost of Capital;
- Resetting the imputation credit ('gamma') value to 0.25 in line with current Australian regulatory practice;
- Using the approved Network Access Price List in determining the network access charges, including any adjustments as necessary.

Cost of Debt

We note the discussion of the relative merits of assessing the Weighted Average Cost of Capital via the cost of bank debt rather than through the corporate bond market. We support the continued use of the corporate bond approach on the grounds that it is the role of the IMO to follow established regulatory practice on such matters and no Australian regulator has used the cost of bank debt approach. It should also be remembered that:

- the IMO's determination of the Maximum Reserve Capacity Price is subject to review by the ERA;

- the Maximum Reserve Capacity Price is an estimate of the marginal cost of entry of additional Reserve Capacity in the applicable Capacity Year. While it is based on a benchmark power station, such a station probably does not exist in practice in respect of all elements and nuances of the benchmark. It is therefore necessary to assess the integrated package represented by the benchmark, and it is generally not appropriate to isolate for review particular aspects of it on a stand-alone basis without consideration of the interrelatedness with other aspects. [That said, we consider resetting the 'gamma' to be an exception as this is a supposedly fixed parameter in an accounting equation.]

Historical variation of the MRCP

We note and support the IMO's commentary to the effect that the Maximum Reserve Capacity Price has been relatively stable since market commencement with the exception of two consecutive extremes caused by a sub-optimal procedure for determining transmission connection costs, which has now been superseded. We consider that the two extreme valuations have created the erroneous perception of a substantial fall in the Maximum Reserve Capacity Price in recent years, while it was actually the former substantial increase that was erroneous. On this basis, we support the pricing outcome of the present review as being appropriately contiguous with historical valuations, especially having regard to matters such as bond yields and the value of the Australian dollar.

Contact

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19 December 2012

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19 December 2012

Attn: Mr Greg Ruthven
Manager, System Capacity
Independent Market Operator
PO Box 7096
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By email: imo@imowa.com.au

Dear Sir

SUBMISSION ON THE IMO'S DRAFT MRCP REPORT FOR 2015-16 CAPACITY YEAR

Merredin Energy is a participant in the South West Interconnected System and owner of the 82MW peaking generation plant recently constructed in Merredin, WA. We welcome the opportunity to provide the attached submission on the Independent Market Operator's Draft Report on the 2015-16 Maximum Reserve Capacity Price published in November 2012.

Yours sincerely

Julian Widdup
Director

SUBMISSION ON THE IMO'S DRAFT MRCP REPORT FOR 2014-15 CAPACITY YEAR

MRCP Review Process

Merredin Energy considered the MRCP for 2014-15 to be materially lower than the actual costs of building a new open cycle gas turbine power station. We were therefore surprised to see the 2015-16 MRCP has fallen a further 3.9% from the previous result.

Merredin Energy is concerned that the continued downward revisions to the MRCP may be a policy response to a preconceived view that the reserve capacity price is too high. The MRCP should not be used to limit new capacity and we note the IMO does not have a stated policy objective to limit excess capacity.

We recognise that sustained over supply of generation capacity results in economic inefficiencies. The Merredin Energy plant was constructed in response to the high demand forecasts contained in previous Statements of Opportunities and the previously MRCP levels (which had made the project economic). The excess supply, which is currently depressing the RCP, is having an adverse effect on Merredin Energy and other generators.

The volume of excess capacity is being compounded by demand side management (DSM). DSM should not be seen as a substitute for peaking capacity. The development of the Merredin power station has added permanent capacity. DSM is not permanent. Participants can opt in and out of the scheme. Furthermore, DSM is not subject to the same testing or dispatch regime or refund penalties and should not receive the Reserve Capacity Price. Generators' reserve capacity revenues are being inappropriately discounted due to the surplus capacity associated with the large degree of DSM registered in the market. While there is a place for DSM in the WEM, we call on the IMO and the RCP Working Group to immediately address the adverse impact and disadvantages borne by generators. At a minimum, DSM should be tested regularly and subject to refunds.

MRCP 15% discount

Merredin Energy encourages the IMO to remove the 15% discount to the MRCP. We believe a review of that parameter would have been more important than several of the other parameters that were recently reviewed.

Merredin Energy recognises the importance and benefit of having the Reserve Capacity Mechanism Working Group consider this issue and we understand the need for the Working Group's decisions to feed into the IMO's rule change proposals. However, our previous experience with making submissions as part of the MRCP public consultation process is that our comments often get little traction. We are always disappointed when the IMO's final report makes reference to previous decisions of a working group, particularly when the working group had not convened to consider the specific comments contained in the public submissions. This was a major shortcoming of the previous MRCP review process completed in 2011. Such a process significantly undermines the usefulness of the public consultation process and should be improved.

We also remain concerned around the delayed timeframe for removing of the 15% MRCP discount factor and recommend the IMO seeks to fast track the removal of that factor.

WACC

The WACC for the 2015-16 MRCP is too low. In our previous MRCP submissions to the IMO, Merredin Energy argued that the inflation, asset beta, equity market risk premium and debt issuance costs were inappropriate (with solid reasoning and evidence).

The IMO has reviewed only some of the existing WACC parameters, such as the gamma. It is poor public policy for the IMO to make judgement calls on which parameters to review and when. Best practice would see the IMO publish guidelines on that point. This would reduce the subjectivity present in the application of the current market procedures.

We note PwC's advice to the IMO dated 19 October 2012 titled *Re: Summary of regulatory decisions related to Reserve Capacity Price* discussed the equity market risk premium. Professor Robert Officer was quoted by PwC in that report, where Officer had made some good points in relation to the EMRP. We understand from PwC's correspondence that it agrees with Officer's stated position, particularly in respect of the risk free rate and EMRP needing to be set using consistent timeframes (either point in time or 'normalised levels'). Contrary to that advice, the current approach is uses inconsistent time periods, with normalised betas and EMRPs but a point in time parameter for the risk free rate. We suggest a review of the asset beta and EMRP is warranted immediately and prior to finalising the 2015-16 MRCP, particularly as the risk free methodology can not be changed barring an amendment to the market procedures.

Given PwC's advice, who were engaged as an expert adviser to the IMO, the IMO should be duty bound to consider and act on that advice of 19 October. Such action should result in a higher and more appropriate EMRP. The recent academic paper *Adjusting the Market Risk Premium to Reflect the Global Financial Crisis* by Bishop, Fitzsimmons and Officer published in FINSIA's Journal of Applied Finance JASSA Issue 1 2011 found the market risk premium to be 9.7% based on the prevailing market volatility at the time of publication. Recognising the movement in markets since that date, an EMRP around 7% would be realistic today.

We consider that financiers will be continue to be concerned by the volatility of MRCP changes and this will, in turn, increase the cost of funding. This volatility should feed into the asset beta and the WACC. We note that no justification for retaining an asset beta of 0.5 has been provided. This number was based on dated historical data that is unreflective of the risks associated with constructing and operating a WEM peaking generation plant. We suggest an asset beta should be at least 0.6 based on the analysis presented in our previous submissions to the IMO.

The expected rate of inflation (parameter (i)) should be derived from the difference in nominal and inflation linked bond yields published by the RBA, rather than taking a single one year projection of 3.25% and nine years of 2.5% which is largely an arbitrary assumption. The IMO's existing methodology is inconsistent with the market procedure as the RBA has not published specific inflation forecasts out to 2022. Using RBA published bond yield data for bonds maturing in 2022, without interpretation or extrapolation, would be consistent with the market procedures and give a more sensible expected inflation result. Based on RBA published bond yield data (as underpinned in Graph 5.9 of the RBA's Statement on Monetary Policy November 2012), long term expected inflation (parameter (i)) should be 2.1%. The RBA inflation linked bond data can be sourced from the following link:

http://www.rba.gov.au/statistics/tables/xls/f02dhist.xls?accessed=2012-12-19-16-46-21

Fixed Fuel Costs

In order to achieve practical completion and reserve capacity certification, a new power generator needs to complete successfully a series of commissioning tests to meet System Management requirements. This include 'cold commissioning' prior to the connection to the Western Power network and 'hot commissioning' which involves the dispatch of power to the grid.

Merredin Energy consumed $2m worth of diesel fuel to comply with the minimum Western Power testing requirements for commissioning our 82MW plant. For a 160MW power station, the fuel costs would have totalled $4m.

As a result of the IMO's capacity credit timetable, the majority of our commissioning had to be undertaken during the months of August and September, when energy prices are typically low. Merredin Energy earned a negligible $27,000 in STEM revenues from the generation of power during hot commissioning over the 2012 winter/spring period. The net fuel costs associated with commissioning had been ignored by SKM in its estimate of fixed fuel.

The fixed fuel costs should increase by $4.0m for the notional 160MW power station.

General Operation and Maintenance Costs

SKM has significantly underestimated the general operation and maintenance costs.

Merredin Energy has recently entered into an O&M agreement and a separate energy dispatch services agreement. The cost of the energy dispatch services is a fixed annual fee of $200,000 regardless of the GWhs generated.

The costs of the energy dispatch services have been completely ignored by SKM. The services are necessary in order to comply with the new balancing market regime including lodging all STEM and balancing bids, commissioning, testing, outage and other notices.

We have engaged Perth Energy to provide energy dispatch services and understand it is the only business that provides such services to independent generators. Accordingly, the fixed O&M costs in the MRCP must be increased by $200,000. If the IMO is minded to continue ignoring those costs, we call on the IMO to make that service available to generators free of charge.

We note very little supporting information has been provided by SKM on the O&M components generally. We consider the general O&M costs including the allocations to plant operator labour and corporate overheads to be substantially understated. It might be useful for a further analysis of the O&M costs be undertaken prior to setting the final MRCP. It would also be useful for SKM to consider the costs associated with staying abreast of and complying with changes to the WEM procedures in the O&M costs.

O&M Consent Parameter

SKM estimated the annual costs of EPA charges and emissions tests to total only $32,000. We would certainly welcome the opportunity for SKM to complete that work for Merredin at a fixed fee of that amount!

The cost of burning diesel for compliance tests should be included in the consent costs. Expected STEM revenues earned from the testing regime could be netted off the costs, although those revenues are likely to be negligible (as discussed above in relation to the commissioning costs). The consent cost parameter should also include the costs associated with maintaining and renewing generation licences and compliance with the Clean Energy Act (Cth) which is a recent additional obligation placed on generators.

Construction insurance

SKM's estimate of construction insurance costs has not been updated and remains inadequate at 0.4%. The IMO, in its report on annual insurance costs, noted insurance premiums had increased 22.5%. It is disappointing that had not identified by SKM as an issue prior to its report having been released. It may be sensible for construction insurance costs to be separately estimated as a MRCP parameter rather than being assessed by SKM and rolled into the M factor.

The construction insurance costs need to be amended to reflect current market rates. Furthermore, the extent of cover needs to be analysed and disclosed. Importantly, because of the capacity credit refund regime, construction insurance needs to cover consequential losses of 24 months for capacity credits refund liabilities (consistent with the approach applied to operational business interruption insurance) to cover loss events during construction that lead to subsequent capacity credit refunds.

Merredin Energy had to take out the following insurance cover during construction:

- Construction Material Damage
- Construction Advanced Business Interruption
- Construction Liability (General and Products Liability)
- Construction Marine Cargo & Marine Advanced Business Interruption
- Directors and Officers Liability Cover

Merredin Energy's insurance premiums totalled $600,000 in our first year of construction. This represented around 0.8% of the EPC contract sum, prior to the 22.5% increase in premiums recently experienced. Based on our calculations, the insurance margin should be at least 1.0%.

We recommend that the IMO undertakes further work to ensure the insurance component of the Margin is set at a sensible level prior to finalising the 2015-16 MRCP.

Annual Insurance Costs

We consider the IMO's allowance for annual insurance costs insufficient.

Merredin Energy recently placed asset replacement and business interruption insurance with Chartis. As part of that process, Chartis required that we commission a site survey annually. Chartis quoted $20,000 cost of the initial survey it was to conduct, with the survey cost charged to Merredin Energy. While that is only a modest cost in the scheme of insurance, we recommend the costs of annual insurance surveys be incorporated in the MRCP. Such a cost is necessary in order to achieve competitive premiums and we note the IMO's proposed rates appear very competitive!

The sums insured are not specifically identified but can be inferred. For asset replacement and business interruption insurance the sum insured should be increased to include:

- $743,800 worth of liquid fuel stored on site. Stored fuel is a valuable commodity and in the event of a total loss, the insurer should be expected to meet the cost of refilling tanks. We remain perplexed as to why any owner of a power station would elect to exclude that from the sum insured.

- Following a total loss event and the rebuild of the plant, further commissioning and testing work would need to be undertaken. The costs of burning diesel to complete the commissioning work would ordinarily be borne by the insurer and therefore needs to be included in the sum insured. Based on Merredin Energy's recent commissioning experience (discussed earlier in this submission) we calculate the increase to the sum insured to be $4.0m for this item.

- The costs of debris removal and decontamination expenses should also be included in the sum insured.

Merredin Energy's business interruption insurance policy has a 30 day deductible period. We would encourage the IMO to consider applying a lower deductible and increase the premium. If the IMO remains minded to maintain a 60 day deductible period (or $4.3m), we would argue it is duty bound to include an allowance for the costs of forced outage refunds to reflect the cost of this self insurance. We would suggest a forced outage of two months for each 30 years of operations (i.e. an average cost of $143,000 pa or 0.06% of the business interruption sum insured).

Any prudent owner of a power station should also maintain minimum workers compensation cover and pollution liability insurance. Pollution liability insurance covers the risks associated with the gradual leakage of diesel from the storage tanks and is essential for a power station owner with 815kL of diesel continually stored on site. These risks can lead to material financial losses and are not covered by standard asset replacement or business interruption insurance. The premia associated with these policies is should be added to the annual insurance costs.

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perthenergy

19 December 2012

Mr Greg Ruthven
Manager, System Capacity
Independent Market Operator
PO Box 7096, Cloisters Square
Perth WA 6850

Sent by email: imo@imowa.com.au

RE: DRAFT REPORT: MAXIMUM RESERVE CAPACITY PRICE FOR THE 2015/16 CAPACITY YEAR

Dear Greg,

Thank you for the opportunity to provide comments on the Draft Maximum Reserve Capacity Price (MRCP) 2015-16 Report released in November 2012. Perth Energy (PE) would like to reiterate our concerns over the MRCP determination formulae and inputs used in its calculation.

The current situation in the capacity market is dysfunctional and we found ourselves having to repeat that the IMO needs to target the true causes of "excess capacity" rather than pursuing wholesale changes to the MRCP/RCP formulae to get the market back on track to encourage future investment.

It is difficult to comment on the MRCP without commenting on the Reserve Capacity Market and the Reserve Capacity Mechanism surrounding the MRCP. We will lay out the issues in turn.

Our main concerns are summarised below, with the attachment on WACC issues providing more detailed information.

- **RCM** - From our own experience of providing capacity in the WEM, PE believes that investment capital will not be attracted to providing peaking plant (within a 2-3 year capacity cycle) unless the price for capacity is relatively predictable. It is unlikely that investors will commit to 20 year investment decisions based on the low WACC and inherent uncertainty and lack of commercial rationale in MRCP/RCP determination. Our view is the current situation will likely jeopardise the provision of new generation capacity in the future. As a retailer this is of significant worry to us as it could reconcentrate the supply side to the detriment of consumers.
- PE acknowledges the IMO's concern over the current excess capacity in the WEM but we have submitted before that this has resulted from once-off factors like the Vesting Contract and an oversupply of 'quasi-capacity' rather than 'true' capacity:
  - The awarding of Capacity Credits that are misaligned with the plant's potential contribution to mitigate peak demand, eg. intermittent plant (which the IMO has dealt with) and Demand Side Management (DSM), which the IMO has yet to deal with;
  - Ineffective use of the IMO's discretion to not certify or partially reduce the certified capacity of plant that have clearly and consistently failed reliability benchmark in the Market Rules; and
  - Forecasting of the Reserve Capacity Requirement (RCR) based on overestimated load forecast in recent years due to the mining boom, and so contributes to a widening of the reserve margin, which in turn is seen as part of excess supply although the total cost of that supply to the market has remained unchanged in absolute terms and would have been absorbed had actual demand matched forecast demand.
- Consequently, PE's suggestions for the RCM are for the IMO to urgently review its DSM policy, apply Market Rules discipline to unreliable capacity and to improve forecasting of the RCR to better reflect actual demand load. These tasks will ensure a more efficient allocation of Capacity Credits

by the IMO to 'true' capacity plant and more accurate system demand forecast in future. We urge the IMO to focus on:

  - Better forecasting could involve requiring discrete loads of greater than 1% of total system demand to have acquired their own bilateral contracted supply for at least 4 years before being allowed to enter the SWIS. The 4-year time frame is to enable the WEM to commercially absorb such loads over time.
  - The pricing of Capacity Credits should be retained as is in structure, with the existing adjustment factor for excess capacity that provides adequate signals to participants. This approach ensures continued predictability of returns for investors to supply peaking capacity to the WEM and also utilisation of existing market mechanisms to more efficiently award Capacity Credits to existing and planned plant that provide 'true' peaking capacity.
  - Making DSM loads equal in operational standards with peaking capacity by requiring them to be part of the merit order of dispatch. It is a breach of Market Objectives to discriminate in favour of DSM, with these loads offered favourable treatment compared to peaking capacity while paying them the full RCP. The RCP is designed specifically for peaking capacity payment in the Market Rules. There is no rationale for System Management to rank DSM loads last to call after exhausting all capacity in the system, or to accord them a 2-hour notice period instead of the standard 15 minute period imposed on peaking plant.
  - Retention of unreliable generation plant distorts the market given that the receipt of Capacity Credits for such plant contributes to them remaining in service. In its Discussion Paper on the WEM Report of November 2012, the ERA has identified plant that has had as low as 50% availability for a number of years, and yet the IMO has not exercised any discipline on them in terms of certifiable level. If Capacity Credits were better related to plant availability, the number of credits allocated to this type of plant would reduce and so influence the economic decision to decommission.

- Dealing promptly and effectively with the above shortcomings would lead to a more balanced and efficient capacity market and take away the pressure on the IMO to constantly change the MRCP/RCP methodology to deal with the perceived excess capacity situation.
- **Maximum Reserve Capacity Price (MRCP)** - PE restates its concerns[1] around many of the inputs used in MRCP determination, especially now that MRCP compilation drivers are formulated to provide a Minimum, not Maximum, Reserve Capacity Price, and unrealistically low network connection costs and Weighted Average Cost of Capital (WACC):

  - As the MRCP is now pitched at the low end of cost estimation, it is critical that the automatic 15% discount to MRCP to derive the RCP should be eliminated. There is unanimous agreement among market participants and IMO that this discount has no basis;
  - The current WACC methodology is inconsistent with investors' expectations of the risks involved in building and operating generation plant – we have attached a paper dealing comprehensively with issues associated with WACC determination and hope the IMO ill be considering it appropriately; and
  - Transmission network connection costs continue to be unpredictable, depending mainly on the location a new project happens to be, and a significant contributor to the overall level of the MRCP. By using an average cost over the last 6 years this major input by definition is not a maximum. It would be better for IMO to take an average of the likely locations for generation capacity development as provided by Western Power (WP). At least this is forward looking, with WP recommending where the lowest cost locations are for a nominal peaking plant to connect to the Grid.

- PE would prefer to see a transmission connection cost methodology that reflects the location (and degree of constraint present) of the connection on the network and the type of load to be supplied. Such a change would see the connection costs charged to those users servicing the market as a whole being 'use of system' charges while those servicing special discrete loads would be charged on more of a user-pays, deeper connection, cost.
- **Ancillary service payment for dual fuel generators** – The Varanus incident in 2008 highlighted the importance of fuel security in the supply of electricity in WA. In particular, on that occasion, a significant contributing factor to the continuation of supply in the SWIS was the ability to switch to distillate fuel at dual fired gas/distillate generators. Without that ability, more severe electricity supply restrictions and extended periods of high and volatile wholesale pricing may have been experienced. On the other hand, when supply constraint is caused by factors other than gas supply, continued use of gas at dual fuel peaking plant helps maintain lower than otherwise energy

[1] These concerns have previously been outlined in PE's submissions to the ERA and IMO.

prices. Therefore, the ability of a generator to offer dual fuel plant helps with overall system supply security and lower costs to consumers. However, designing and maintaining a dual fuel facility increases both initial capital costs (eg. certain gas turbine type or feature and additional fuel infrastructure) and ongoing operating costs (eg. needing to maintain gas transportation contract).

The current Market Rules do not adequately compensate for the costs of providing dual fuel capabilities. PE proposes an ancillary service payment for the provision of dual fuel capability. Facilities that qualify for dual fuel status, as per the current criteria contained in the Market Rules, would be eligible to be paid the dual fuel ancillary service fee from System Management.

Please do not hesitate to contact us should you have any queries.

Yours sincerely,

Ky Cao

Managing Director

APPENDIX A – Examination of WACC Parameters and Related Matters in MRCP Calculation

Contents

1 Executive Summary

The Independent Market Operator (IMO) is required to determine the Maximum Revenue Capacity Price (MRCP) for the Wholesale Electricity Market (WEM) on an annual basis in accordance with the Market Procedure: *Maximum Reserve Capacity Price*.

The MRCP is used to determine an administered Revenue Capacity Price in the absence of a Reserve Capacity Auction, or the maximum bid price in an Auction.

The IMO recently published its Draft Determination of the MRCP (Draft Determination) for the 2013 Revenue Capacity Cycle, which will be effective for the year 1 October 2015 to 1 October 2016, and is seeking submissions on its Draft Determination.

Additionally, the Economic Regulation Authority (ERA) is required to report to the Minister for Energy at least annually, on the effectiveness of the WEM in meeting the Wholesale Market Objectives. To assist this process, the ERA has recently published a Discussion Paper to assist stakeholders make submissions on matters that include the effectiveness of the process used to set the Reserve Capacity Price (Discussion Point 3 of the Discussion Paper).

The paper sets out Perth Energy (PE)'s submission on a number of issues that are relevant to both the IMO's Draft Determination and the ERA's Discussion Paper; principally

- the effectiveness of the Reserve Capacity Price set using the administrative formula in the Market Rules with reference to the MRCP and the Excess Capacity Adjustment; and
- the IMO's approach to calculation of WACC and the incentives that it delivers for investment in reserve capacity and hence the implications for achieving Market Objectives.

This paper explains the basis of PE's view that the effectiveness of the Reserve Capacity Price set using the administrative formula in the Market Rules is impaired by the approach adopted by the IMO to calculating WACC for the MRCP. The Capital Asset Pricing Model used by the IMO, if applied appropriately and calibrated against wider evidence, has the potential to be effective. However the approach currently adopted by the IMO does not meet Market Objectives of:

- promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS; and
- encouraging competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;

because the WACC and MRCP that result from the IMO's approach:

- does not result in an economically efficient price for the efficient, safe and reliable production and supply of electricity services in the SWIS; and
- consequently does not provide pricing that facilitates efficient market entry and hence competition in the generation sector.

The IMO's approach to setting a Reserve Capacity Price includes applying a weighted average cost of capital (WACC) to a benchmark asset base. The WACC is a critical component of the MRCP, profitability for generators providing reserve capacity and hence incentive for generators to participate in and provide an efficient wholesale market.

The IMO uses the capital asset pricing model (CAPM) to determine WACC. This is a widely accepted model for determining benchmark rates of return for both commercial and regulatory purposes. It provides a reasoned transparent approach, but its calculation requires commercial judgment to determine a number of its critical parameters, and it is by no means an exclusive means of determining returns. It can be complemented and corroborated by comparisons and financial analysis such as financability testing. These further methods are briefly described later in this summary.

A key intent of the CAPM is to identify returns that match the risk characteristics and investor expectations of different kinds of businesses. The different parameters that feed into the CAPM account for different risk characteristics. The provision of reserve generation capacity requires investors to bear risks particular to that activity. Not all of those risks and hence CAPM parameters will be necessarily unique to the provision of reserve generation capacity, but there are a number of characteristics and risks that strongly distinguish such a business from others.

In applying the CAPM approach to determining the WACC for the MRCP, the IMO has relied on and narrowly referred to, precedents and parameters set by regulators of monopoly businesses.

The IMO's approach of following regulatory precedent may not be unreasonable, but the rationale for its approach of apparently so rigidly and restrictively following a relatively narrow band of regulatory precedent using the parameters of network business and the Western Australian electricity network sector in particular, is unclear. Generation may share some risks by virtue of participating in the same market as network assets, but it is not reasonable or realistic for the IMO to assume that the risks are identical and to exclude from consideration a wider body of regulatory and pricing precedent. The consequences are that the IMO:

- has developed WACC for the MRCP by including parameters and risks that are not relevant to the provision of generation capacity, which inevitably leads to distortions in both pricing and signals for efficient investment;
- does not seem to have followed an internally consistent approach to applying the CAPM to the MRCP; and
- has not in its Draft Determination cross checked the outcomes of its assumptions and approach to determining WACC to other availability data or undertaken financial analysis to test the business impact of its Draft Determination.

Examples of these consequences are summarised below.

Inappropriate WACC parameters

Section 2 of this paper explains that there is a wide range of information and regulatory precedent that is more relevant to the derivation of WACC parameters for generation businesses, than the narrower precedents to which the IMO has referred. Section 3 illustrates how this has led to the IMO's WACC being significantly misstated. For example, Section 2 illustrates that the IMO's approach appears to have materially misstated:

- the risk free rate;
- equity beta;
- the debt risk premium;
- gearing; and
- gamma.

The IMO sought advice from PriceWaterhouseCoopers[2] (PwC) to inform its determination of WACC parameters. However, the terms of reference for advice it provided to PwC restricted the research to three WACC parameters[3] and to regulatory decisions made by regulators subject to merit reviews[4]. Accordingly, PwC was obliged to ignore regulatory decisions made by other economic regulators which may be appropriate to consider in the context of the decision on the MRCP. It seems important that the IMO should consider all information to ensure that the decision making approach is appropriate for the MRCP.

Internally inconsistent WACC parameters

The IMO approach includes parameter values carried over from previous reviews as well as parameters that are recalculated annually. Although, perhaps inconsistently with this approach, one of these "fixed" parameters, the gamma, was reviewed by PwC in its report due to a recent Australian Competition Tribunal (ACT) decision, which changed the value used by other Australian regulators.

[2] PwC, 19th October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Reserve Capacity Price

[3] The risk free rate, the debt risk premium and the gamma.

[4] Such as the Australian Energy Regulator and the Economic Regulation Authority of Western Australia.

In particular, members of certain pairs of WACC parameters are interrelated. One member of the pair does not operate independently of the other. However, for two of the pairs, the IMO's approach holds the risk of internal inconsistency in its calculation of WACC because one member of a pair is updated and the other is not:

- the risk free rate (updated annually by IMO) and the market risk premium (updated by IMO every five years); and
- the debt risk premium (updated annually by IMO) and debt issuance costs (updated by IMO every five years);

In general, the IMO has followed network business precedent for WACC parameters - except for the gearing rations which are more akin but still in excess of available data for, generation businesses.

Absence of calibration of the of outcomes of the IMO's approach

The IMO's approach focuses heavily on the WACC parameters, but not on the resulting WACC. WACC parameters are an input to a pricing outcome, not the outcome itself. The resulting WACC should be calibrated against expectations of industry norms and the objectives of the pricing regime, to help check test all the parameters are appropriate.

For example, regulators in the United Kingdom and IPART commonly use financeability tests to determine whether the rate of return outcomes from the CAPM are consistent with regulators' obligations to balance the interest of investors and customers and to maintain the financial viability of regulated businesses. A financeability test examines the future cash flows that result from rate of return decisions and tests whether they enable a business to meet the regulator's assumed or target credit ratings and key financial ratios that measure financial viability and health. IPART has recently reaffirmed its commitment to using these tests as part of its approach to regulation going forward[5].

PE has compared:

- the results of the IMO's draft WACC determination and its own illustrative calculation of an appropriate WACC, using more apt parameters which are explained and justified in this paper; against
- comparable WACC's for generators and energy retailers, which unlike the network businesses on which the IMO has based its WACC, participate in the wholesale energy market.

The results, which are set out in Sections 3 and 4 of this paper show that:

- the IMO's Draft Determination produces a WACC that is significantly below the level of WACC indicated by:
  - market evidence for generation businesses;
  - regulatory precedent for retail businesses, which would appear significantly closer in their risk profile to generation than the network precedent on which the IMO has relied; and
  - the use of more appropriate WACC parameters indicated by Section 2 of this paper.

[5] For example see IPART, September 2012, Financeability test in price regulation, www.ipart.nsw.gov.au

2 The IMO's calculation of WACC

2.1 The IMO's approach to calculating WACC

The 2015/16 MRCP has been reduced from the previous 2014/15 determination by 6.8 per cent, with the largest single factor attributed to changes in WACC.[6]

The IMO has applied the Capital Asset Pricing Model (CAPM) to calculate the WACC for the MRCP.

The CAPM is a widely accepted technique for calculating a benchmark rate of return for a business. While it is commonly used by access regulators to calculate regulated rates of return for monopoly businesses, there is no constraint on the use of CAPM for such businesses.

The calculation of a WACC under the CAPM requires a range of specific input parameters to the CAPM to be determined.

However, in deriving the input parameters for the WACC for the MRCP, the IMO has:

- referred to regulatory precedents that apply to access regulated monopoly industries and services; and
- drawn heavily on parameters and precedents applicable to network businesses.

This does not appear appropriate or rational because:

- reserve capacity is provided by the generation sector which normally operates in competitive markets. Precedents provided by commercial and market practice, not regulatory practice would be applicable; and
- the operational and investment risks of generation businesses are significantly different to network businesses and revenue capped network businesses in particular. For example, generation businesses are subject to fuel price and supply risk and risks of competition and significantly greater volatility in demand and price.

2.2 Calculating WACC

The IMO's Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year - November 2012, included the following Real and Nominal Pre-tax WACCs and associated parameters.

[6] IMO, November 2012, Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year.

Table 2-1 – Capital Asset Pricing Model parameters

Paper Ref	CAPM Parameter	Notation/ Determination	Review Frequency	Value set or TBD	IMO Draft (y=0.5)	IMO Draft (y=0.25)
2.4	Nominal risk free rate of return (%)	*Rf*	Annual	TBD	3.13%	3.13%
2.5	Expected inflation (%)	*i*	Annual	TBD	2.57%	2.57%
2.4	Real risk free rate of return (%)	*Rfr*	Annual	TBD	0.55%	0.55%
2.6	Market risk premium (%)	*MRP*	5-Yearly	6.00	6.00%	6.00%
2.7	Asset beta	βa	5-Yearly	0.5	0.5	0.5
3.7	Equity beta	Be	5-Yearly	0.83	0.83	0.83
2.8	Debt risk premium (%)	*DRP*	Annual	TBD	2.94	2.94
2.9	Debt issuance costs (%)	d	5-Yearly	0.125	0.125	0.125
	Corporate tax rate (%)	*t*	Annual	TBD	30%	30%
2.10	Franking credit value	γ	5-Yearly	0.5	0.5	0.25
2.11	Debt to total assets ratio (%)	*D/V*	5-Yearly	40	40%	40%
3.11	Equity to total assets ratio (%)	E/V	5-Yearly	60	60%	60%
	Nominal pre-tax cost of debt				6.20%	6.20%
	Nominal Post-tax cost of equity				8.11%	8.11%
	WACC (Nominal Pre-tax)				**8.20%**	**8.76%**
	WACC (Real Pre-tax)				**5.49%**	**6.03%**

Note: The IMO determined in its discussion paper that the values for some parameters would be set and some would be determined based on current observations.

The difference between the two IMO versions is Gamma, which is highlighted.

Source – IMO spreadsheets http://www.imowa.com.au/mrcp, as referred to in the IMO Draft Report

2.3 WACC Parameters

PE provides commentary on the specific WACC parameters employed by the IMO, below.

PE also notes that the IMO engaged PwC to provide with information and commentary on regulatory precedents for on certain WACC parameters[7], namely:

- the risk free rate;

[7] PwC, 19 October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Resource Capacity Price.

- the debt risk premium; and
- gamma.

However, the terms of reference provided by the IMO to PwC (and noted by PwC as a constraint) were limited to these three parameters only and required PwC to only identify precedents that were applied from determinations that are subject to a merits review process. This effectively limited PwC's research to decisions made by the Australian Energy Regulator (AER) and the Economic Regulation Authority of Western Australia (ERA). It is assumed that this requirement was implemented to ensure that the regulatory precedents used as part of this review process would be more robust. However, the rationale for this is open to question.

This requirement limits the number of precedents available for the IMO to consider as part of this review, which may reduce the IMO's ability to achieve a regulatory outcome consistent with its objectives given the specific nature of the service being provided. In particular, regulators not subject to merit reviews are subject to other arrangements which ensure the quality of their decisions such as:

- legislative requirements – requirements in the legislative framework may dictate the process used by the regulator in forming its decisions. Where regulators do not meet these requirements, they may be bound in breach of these requirements; and
- terms of reference for the review – where terms of reference are drafted by Government at the commencement of the pricing review, these terms may provide instructions on the approach to be used to make decisions, limiting the ability of the regulator to make decisions or use methods outside the terms of reference.

Importantly, it is not clear that any other Australian regulator has included this restriction in its approach to evaluating regulatory precedents. In fact, regulators such as the AER consider approaches taken by state based regulators such as IPART and the QCA when making pricing decisions.[8]

The ERA in recent pricing decisions has taken a particularly aggressive stance to price regulation, providing atypical results.[9] By placing undue weight on precedent set by the ERA, it is likely that the IMO will determine a MRCP, with similarly atypical results.

In addition, the IMO sets the price of generation capacity, not transmission and distribution network services. The MRCP prices a fundamentally different service. Given the nature of the prices being regulated by the IMO, there may be some benefit in considering a wider pool of regulatory precedents in evaluating the appropriate level of the MRCP. For example, the IMO does not appear to have considered taking into account regulatory precedents for WACC for retailers, for regulated retail tariffs whose participation in wholesale electricity markets would indicate a risk profile closer to a generation business, than a network business. Examples include IPART's review of retail electricity tariffs in 2010 where it considered WACC for a retailer and a generator, and market observations on some WACC parameters for listed companies in Australia operating in the generation sector. Section 4 of this paper illustrates these precedents.

2.4 Risk free rate

The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments.

The risk free rate is used as a direct input into the CAPM to determine the required return on equity. It is also used as an input into the calculation of the required cost of debt.

Given that no asset is truly 'risk free', a proxy is used to determine the risk free rate. Common regulatory practice is to use government bonds. In Australia, this generally refers to the yields from Commonwealth

[8] For example, the AER in its 2009 review of WACC parameters (*Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*), considered examples for the equity betas and gamma from state jurisdictional regulators such as IPART, the QCA, ESCOSA and others.

[9] Due to a variety of reasons, the WACC included in the most recent ERA decision, *Final decision on proposed revisions to the Access Arrangement for the Western Power Network*, a lower WACC than recent decisions made by other Australian regulators.

Government Securities (CGS). Perth Energy understands that the IMO has calculated this following regulatory precedents, on the basis of current yields on Commonwealth Government bonds.

However, the IMO has noted that its stakeholders consider that the current depressed values for the risk free rate is more a product of market characteristics (a flight to safety) than an appropriate estimate of the risk free rate that should be applied in the calculation of the WACC. PE considers there to be considerable support for a more long term approach to estimating the risk free rate under current market conditions. This support includes precedent and a recent Australian Competition Tribunal (ACT) decision , *Application by EnergyAustralia and Others (No 2) [2009] ACompT9*.

In the ACT's decision, EnergyAustralia proposed an averaging period for determining the risk free rate that '*is closest to the regulatory control period prior to the emergence of the marked acceleration of the global financial crisis in September 2008'*. This period was proposed on the basis that:

- the AER's specified averaging period for observing key financial data is highly likely to include data that has been impacted by this supervening critical event; and
- *'an averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return … which is materially biased below the rate of return required by investors in a similar commercial business'*.

The ACT upheld EnergyAustralia's appeal, and the averaging period proposed by EnergyAustralia was used in its final determination.

Referring to Figure 1 of the IMO's Draft Determination, PE estimates that if the principles set out in the ACT Decision were applied to bond rates immediately prior to the impact of the Euro currency crisis in mid 2011 that has skewed the markets below long term averages, an appropriate risk free rate would be of the order of 5.0 per cent to 5.5 per cent (nominal).

A further precedent for calculating the risk free rate which addresses this volatility is provided by SA Water in its recent pricing proposal[10], which proposed a 180 day observation period to average out the outliers and extend the sample size. In particular, SA Water mentioned that:

- actual financing costs may differ significantly from those estimated under a 20 day averaging period; and
- the 20 day averaging period does not take into account the potential variability in debt market conditions over the regulatory period.

In the SA Water example, a 180 day averaging period to 1 June 2012 for a 10 year Commonwealth Government Bond provided a nominal risk free rate of 3.93 per cent.[11]

Perth Energy submits that the risk free rate for the MRCP (to be applied in 2015 and 2016) should be consistent with the ACT's views and not be distorted below long term averages. Accordingly, a nominal risk free rate of the order of 4 per cent to 5 per cent or more, appears appropriate and significantly less likely to result in distorted pricing than the atypical rate of just over 3 per cent (nominal) included in the IMO's Draft Determination.

2.5 Inflation

Perth Energy notes that the inflation is set at 2.57 per cent which is close to the mid point in the Reserve Bank of Australia target range of 2 per cent to 3 per cent. This is likely to be close to the outturn inflation rate due to the Reserve Bank's actions on adjusting interest rates. The forecast inflation rate is consistent with generally accepted economic forecasts.

[10] [10] SA Water business proposal to ESCOSA http://www.escosa.sa.gov.au/library/121012-SAWaterRegulatoryBusinessProposal_2013.pdf

[11] Using the SA Water example – 180 days observed up to 1 June 2012 on 10 year Commonwealth Government Bonds

2.6 Market risk premium

The market risk premium (MRP) is the expected return over the risk free rate that equity investors would require in order to invest in a well-diversified portfolio of risky assets. It represents the risk premium that investors can expect to earn for bearing only non-diversifiable or systemic risk.

Estimating a forward-looking market risk premium, commensurate with the current market, generally involves having regard to historical estimates on the basis that investors' forward-looking expectations will be based on past experience. Current regulatory practice in Australia is to estimate the market risk premium using historical data on equity premia.

In the past, Australian regulators consistently applied a market risk premium of 6 per cent. However, in its 2009 review of WACC parameters, the AER concluded that the market risk premium should be increased to 6.5 per cent on the basis of market conditions at the time. Nevertheless in its final decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, the AER used a market risk premium of 6 per cent for the gas business.

In the ElectraNet draft decision[12] (November 2012), the market risk premium was set at 6.5 per cent, consistent with the AER WACC review of May 2009[13], and consistent with ElectraNet's proposal. Murraylink, a single asset transmission interconnector also received a draft decision in November 2012 with an MRP of 6.5 per cent. This is consistent with 6.5 per cent allowed for ETSA Utilities more than two years ago in 2010. These decisions reflect the regulators view that current market conditions remain inconsistent with normal, longer term market conditions and that a higher MRP is warranted.

PE submits that the MRP should represent that component that, when applied in a CAPM, offers sufficient incentive for an investor to make efficient investment in new generation capacity in the WEM. Whilst PE acknowledges that the MRP is not business dependent, it seems difficult to understand how a more risky business operating in more difficult times might be fairly treated by an MRP which was less than that applied in a network business.

PE suggests that the MRP of 6.5 per cent should be considered particularly in light of its concerns about the capacity of the other WACC parameters determined by the IMO, to adequately deal with generator risks.

2.7 Equity beta[14]

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. That is, it represents the riskiness or volatility of the business' returns relative to the diversified market position as a whole.

Under CAPM, it is assumed that investors can diversify away business-specific risk and therefore only require compensation for bearing non-diversifiable or systemic risk (that is, risk associated with movements in the market as a whole).

An equity beta of one implies that the business' returns have the same level of systemic risk as the overall market. An equity beta of less than one implies that the business' returns are less sensitive to systemic risk, while an equity beta of more than one implies that the business' returns are more sensitive.

In its 2009 WACC Review[15] (for network businesses), the AER changed its previously held position on the value of the equity beta for electricity distribution and transmission businesses from 1.0 to 0.8.

Because the AER WACC review sets some parameters for a period until the next WACC review, the equity beta applied in the recent ElectraNet draft decision was 0.8 (November 2012). This was applied to a

[12] AER Draft decision on South Australian electricity transmission revenues available at: http://www.aer.gov.au/sites/default/files/ElectraNet%202013%20-%20AER%20-%20draft%20decision%20-%2030%20November%202012.pdf

[13] AER, Statement of the revised WACC parameters (transmission), May 2009, page 6.

[14] This section does not explicitly discuss the asset beta, since this is a derivative of the equity beta.

[15] AER 'Electricity transmission and network service providers – review of the WACC parameters,' Final Decision, May 2009

business with approximately $2 billion in assets, operating a monopoly transmission business under a revenue cap approach. This is therefore a significantly less risky business with more stable revenue streams than a generation business supply reserve capacity.

The question of whether it is appropriate to use the equity beta applied to distribution and transmission businesses in a process to determine an MRCP in WA depends on an assessment of whether there is a difference in the systemic risk faced by network monopolies as compared to generation businesses. Reasons for any differences are primarily due to the nature of activities undertaken by the businesses and the costs incurred. A summary of some of the key differences is set out below.

Table 2-2 – Differences in risk (Generation v Network)

Factor	WA Generation	Australian Electricity Transmission Network business
Beta	0.83 (IMO draft)	0.80 (ElectraNet draft)
Business Revenues	Subject to price bids and competition	Revenue cap – mostly guaranteed
Market Volumes	Subject to weather conditions, government policy, customer demand changes, technology, innovation	Revenue cap – prices adjusted to recover required revenue
Operating costs	Subject to fuel, labour and material variances	Subject to labour and materials variances
Competition	At risk of new entrant exploiting new technologies before end of life	Monopoly licence area

There are further risks specific to the provision of generation capacity that are not considered in any way in a beta derived for a network business and seem very unlikely to be accommodated together with the other risks outlined above, in a differential beta of only 0.03. For example:

- construction delays can place at risk investors' security deposits provided when IMO approved the project and allocated capacity credits to that project. The security is 25 per cent of one year's capacity payment, a substantial sum to put up at the start of the construction process. It is common to have project delays and funders are aware of this and have priced in this risk as power plants cannot pass on additional costs to contract counterparties;
- delay in delivering the plan can lead to capacity refunds. This penalty in the summer period can be as high as six times the revenue received. Accordingly, an entire year's capacity payment could be lost in two months of down time, or if construction delay creeps past the end of the year in which capacity is intended to come on line. Again, such delays and refund penalties have been incurred by most projects;
- a business can be at risk of distress by losing much less than a year's revenue. Losing say 20 per cent of a year's revenue would be enough to lock up equity or cash in a project. It is not clear whether the IMO has considered practical project financing risks that businesses face to provide generation capacity; and
- exposure of investment in generation capacity to forced outages that are beyond the control of a generator.

PE notes that:

- the generators offering reserve capacity for the SWIS do not have a natural monopoly as there are currently 29[16] generation plants operated by 15 generation businesses in the SWIS; and
- the notional 160MW generator used by the IMO in calculating the MRCP represents less than 3 per cent[17] of the WEM, and therefore will not have market power.

PE observes that the Beta of 0.83 is only a fraction above the 0.80 allowed for network businesses. This does not reflect the commercial and market risks of a WA generator when compared to a monopoly network business, and a WACC that recognises this low beta fails to offer sufficient financial incentive to invest in new generation when compared to a regulated network business in the National Electricity Market.

There are listed Australian generators for which a beta can be measured from empirical evidence. (There are other listed generators but arguably other business interests such as energy retailing mask the

[16] 29 Generators of 10MW capacity or more as listed in the Energy Supply Association of Australia annual report
[17] Based on 6,000 MW as listed by the Energy Supply Association of Australia annual report

generation beta.) The five year average beta observed for three Australian Generators (Energy Developments Ltd, Energy World Corp Ltd and Pacific Energy Ltd) is slightly more than 1.0.

PE submits that a beta of 1.0 would be a conservative reflection of the business specific risks associated with generation in the WEM, and offers the minimum financial incentives required for investment in generation capacity.

2.8 Debt risk premium

The debt risk premium is the additional return over the risk free rate required by investors to hold debt that is not risk free (that is, where there is a risk of default). The purpose of including the debt risk premium within the expected cost of debt is to compensate for the benchmark cost of debt capital.

In its Draft Determination, the IMO "has applied the value that represents a strict application of the ERA's approach in the WA Gas Network final revised decision, utilising bands with credit ratings of BBB and BBB+, with a term to maturity of at least two years."[18]

The regulatory approaches reviewed by PwC for the IMO[19] consider the debt risk premium for network businesses. This is not appropriate for the MRCP because it is required to reflect the cost of providing reserve generation capacity rather than a monopoly network system. Differences between the two types of assets may impact:

- the credit rating associated with the business. Generators typically operate in a more competitive market unlike networks, and may be considered riskier assets as a result (see section 2.5 above);
- network businesses can be order of magnitude greater in terms of capital value, than generation businesses and this too will lead to a reasonable expectation that a provider of reserve capacity might expect to experience a higher cost of debt than a network business; and
- the time to maturity of debt financing, and the relevant gearing levels may differ between generation and network businesses.

In addition, the IMO's Draft Determination notes that stakeholders have suggested that they are more likely to access bank financing rather than corporate debt market financing. In network price regulation, debt market financing is used because it is assumed that the regulated businesses have access to these markets. It would be reasonable to assume that network businesses would have access to debt markets. However, it may not be axiomatic that this is also true for a less capital intensive business such as a benchmark provider of Reserve Capacity. There are regulatory precedents for this, which appear more relevant than the large network business precedents on which the IMO has drawn. It would be appropriate for the IMO to consider this matter and its impact on the debt risk premium.

For example, in the case of price regulation of smaller transport firms, IPART considered the costs of bank related financing[20], notwithstanding

The IMO has outlined a range of complex and esoteric, large scale network based precedents to support a debt risk premium of 2.94 per cent in its Draft Determination.

However Perth Energy observes that:

- the premia represented by the differential between the five year Australian Government Bonds (GACGB5) and the BBB Corporate Bonds (C356Y) as at 30 June 2012 are:

  A.1 when measured on a 20 day average to 30 June: 3.69 per cent;

  A.2 when measured on a 40 day average to 30 June: 3.69 per cent; and

  A.3 when measured on a 180 day average to 30 June: 3.61 per cent

- the IMO's Draft Determination does not recognise that the risks of a generation business differ significantly from network businesses' risks on which it has based its debt risk premium; and

[18] IMO, November 2012, Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year, p 22.

[19] PwC, 19th October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Reserve Capacity Price

[20] IPART, Review of fares for private ferry services and the Stockton ferry service for 2012 - December 2011*, page 31, available at* *www.ipart.nsw.gov.au*

- the IMO's Draft Determination does not recognise that a generation business is less likely to be able to access bond markets and achieve a BBB credit rating.

Because of these reasons, Perth Energy submits that a debt risk premium of ***at least*** 3.6 per cent would be more appropriate to the calculation of WACC for the MRCP.

2.9 Debt issuance costs

While using a consistent level for some parameters over time is a well accepted approach to price regulation (for example, the market risk premium is often kept stable over time by regulators), it seems reasonable to question whether debt issuance costs should be left fixed while the debt risk premium is calculated annually. In times of uncertainty, the costs of issuing debt can vary. This may coincide with large changes in the debt risk premium. Given the potential for debt issuance costs to vary, there may be a benefit in calculating the debt.

2.10 Gamma

A full imputation tax system for companies has been adopted in Australia since 1 July 1987. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities may be best viewed as personal income tax collected at the company level. With the full tax imputation system in Australia, the company tax is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

The actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of:

- the franking credits that are created by the firm through the payment of Australian company tax and most importantly the value of credits that are distributed; and
- the value that the investor attaches to the credit, which depends on the investor's tax circumstances (that is, their marginal tax rate and whether they can use the franking credits).

As these factors will differ across investors, the value of imputation credits may be between nil and the full value of franking credits (i.e. a gamma value between zero and one).

There has been and continues to be significant debate concerning the appropriate value to ascribe to imputation credits.

PE submits that the move from a gamma of 0.5 to 0.25 recognises that there are different investors participating in the market and that international investors and others do not value franking credits in the same way as an Australian resident taxpayer. The adoption of a gamma of 0.25 in the Australian Competition Tribunal decision recognises the reduction in value of franking credits attributed to a mix of equity providers. It is noted that there are many instances of Australian generation businesses with foreign ownership to support the notion that franking credits should be valued at the lower end of the scale. Australian generators with foreign ownership apart from PE include:

- Alinta Energy;
- Meridian Energy;
- ATCO Australia;
- TruEnergy;
- IPR-GDF SUEZ Australia;
- Intergen (Australia);
- Mitsui; and
- Transalta.

Given that the generation sector is more likely to need foreign investment to satisfy the equity needs for a new generation project, the gamma should be zero, or at least approach zero to offer sufficient incentive to maintain access to the necessary capital and provide benefits of competition in the WA generation market.

2.11 Gearing

Gearing is defined as the ratio of the value of debt to total capital (that is, debt over debt plus equity). For regulatory purposes, the benchmark gearing ratio is usually considered to be the capital structure of a benchmark efficient business. This is intended to provide companies with an incentive to manage the costs associated with debt and equity efficiently.

Regulated network businesses have typically received gearing levels in regulatory decisions of 60 per cent debt and 40 per cent equity. This is evidenced in regulatory decisions such as the recent ElectraNet decision in November 2012.

PE notes that the gearing in the IMO Draft Determination provides gearing with 40 per cent debt. This is lower gearing than for network businesses for example and is more consistent with the typical structures of generation businesses.

Our research into listed Australian generators (Energy Developments Ltd, Energy World Corp Ltd and Pacific Energy Ltd) identified an average debt of 27 per cent and 28 per cent for two year average and five year average observations.

Therefore:

- the debt to equity ratio assumed by the IMO appears more consistent with the generation sector, albeit with a higher debt ratio than is experienced in the sector; and
- the IMO's approach of recognising the distinguishing characteristics of the generation sector in this WACC parameter, but not in others, appears to be mutually inconsistent and supports PE's view that the WACC for the MRCP should be based on relevant generation sector business characteristics.

3 An illustrative appropriate WACC for the MRCP

The discussion in the previous chapter demonstrates views on the WACC parameters that recognise

- more appropriate market conditions and observations;
- the fact that this decision is for the generation sector and not a monopoly network sector; and
- the need to drive appropriate incentives to attract generation investment in the SWIS.

Section 4 overleaf demonstrates that the illustrated WACC above is more closely aligned with market outcomes and relevant WACC determinations than the IMO's Draft Determination.

The following table compares the IMO Draft Determination with the WACC that more appropriate WACC parameters provides. It illustrates that the IMO Draft Determination appears to have materially understated WACC.

Table 3-1 – Capital Asset Pricing Model parameters

CAPM Parameter	**Notation/ Determination**	**IMO Draft (y=0.5)**	**IMO Draft (y=0.25)**	**Illustrative**
Nominal risk free rate of return (%)	*Rf*	3.13%	3.13%	5.00%
Expected inflation (%)	*i*	2.57%	2.57%	2.57%
Real risk free rate of return (%)	*Rfr*	0.55%	0.55%	
Market risk premium (%)	*MRP*	6.00%	6.00%	6.00%
Asset beta	βa	0.5	0.5	-
Equity beta	Be	0.83	0.83	1.00
Debt risk premium (%)	*DRP*	2.94%	2.94%	3.60%
Debt issuance costs (%)	d	0.125	0.125	0.125
Corporate tax rate (%)	*t*	30%	30%	30%
Franking credit value	γ	0.5	0.25	0.00
Debt to total assets ratio (%)	*D/V*	40%	40%	35%
Equity to total assets ratio (%)	E/V	60%	60%	65%
Nominal pre-tax cost of debt		6.20%	6.20%	8.73%
Nominal Post-tax cost of equity		8.11%	8.11%	11.00%
WACC (Nominal Pre-tax)		**8.20%**	**8.76%**	**13.27%**
WACC (Real Pre-tax)		**5.49%**	**6.03%**	**10.43%**

Note: The IMO determined in its discussion papers that the values for some parameters would be set and some would be determined based on current observations.

Source – IMO spreadsheets http://www.imowa.com.au/mrcp.

4 Comparative WACCs observed in other decisions and in the market

The IMO's calculation of WACC has failed to recognise other regulatory decisions and market observations and instead has relied on network based regulatory precedent and assumptions. The IMO has therefore presented a view which is not representative of market conditions.

The following table compares the IMO WACC (with a gamma of 0.25) with:

- recent WACC determinations by IPART[21] for the retail and generation sectors; and
- WACC in the generation and retail sectors calculated based on:
  - 5 years' market observations of beta and gearing for five Australian businesses for which data is available;
  - assumptions for the risk free rate, debt margin, debt issuance costs, and market risk premium consistent with the illustrative example used in section 3; and
  - gamma which is set at 0.25 to recognise the fact that the examples are Australian listed corporations.

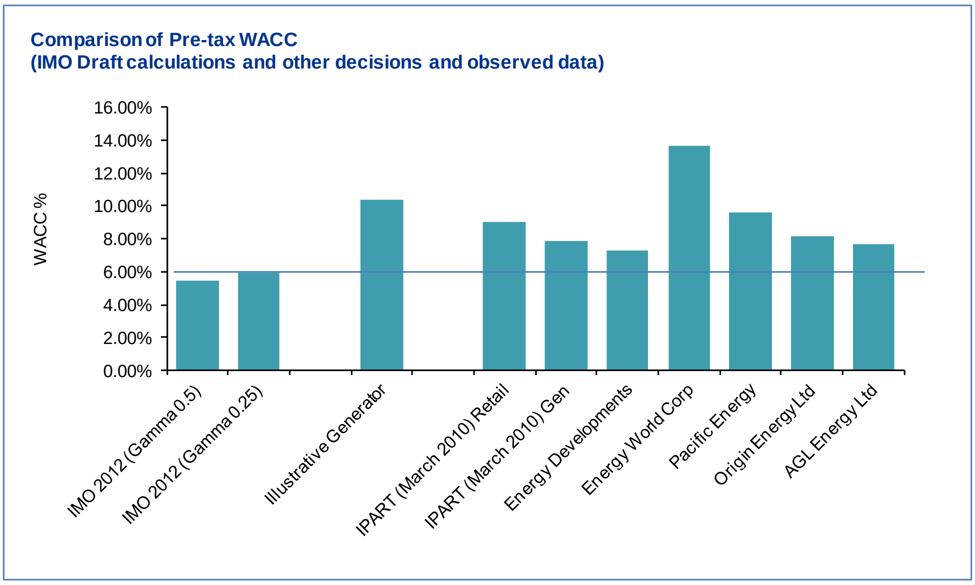
Table 4-1 – Capital Asset Pricing Model parameters

		Regulatory Decision		Market observations of Beta and Gearing				
CAPM Parameter	**IMO Draft (y=0.25)**	**IPART March 2010 Retail**	**IPART March 2010 Generation**	**Energy Developments**	**Energy World Corporation**	**Pacific Energy**	**Origin Energy**	**AGL Energy**
Nominal risk free rate of return (%)	3.13%	5.50%	5.50%	5.00%	5.00%	5.00%	5.00%	5.00%
Expected inflation (%)	2.57%	3.00%	3.00%	2.57%	2.57%	2.57%	2.57%	2.57%
Real risk free rate of return (%)	0.55%							
Market risk premium (%)	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Asset beta	0.5							
Equity beta	0.83	1.00	1.00	0.63	1.49	0.93	0.65	0.57
Debt risk premium (%)	2.94%	2.85%	2.85%	3.60%	3.60%	3.60%	3.60%	3.60%
Debt issuance costs (%)	0.125%	0.00%	0.00%	0.125%	0.125%	0.125%	0.125%	0.125%
Corporate tax rate (%)	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Franking credit value	0.25	0.40	0.40	0.25	0.25	0.25	0.25	0.25

[21] IPART, March 2010, Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity – Final Report

Debt to total assets ratio (%)	40%	30.00%	50.00%	47.00%	15.00%	24.00%	18.00%	17.00%
Equity to total assets ratio (%)	60%	70.00%	50.00%	53.00%	85.00%	76.00%	82.00%	83.00%
Nominal pre-tax cost of debt	6.20%	8.35%	8.35%	8.73%	8.73%	8.73%	8.73%	8.73%
Nominal Post-tax cost of equity	8.11%	11.50%	11.50%	8.78%	13.94%	10.58%	8.90%	8.42%
WACC (Nominal Pre-tax)	**8.76%**	**12.32%**	**11.19%**	10.11%	16.60%	12.47%	10.99%	10.50%
WACC (Real Pre-tax)	**6.03%**	**9.05%**	**7.95%**	7.35%	13.68%	9.65%	8.21%	7.73%

The comparison, which is shown graphically overleaf, illustrates that the IMO's WACC is significantly less than independent derived comparatives for generators and other participants in wholesale electricity markets.



What is most relevant in this comparison are the facts that:

- IPART chose to apply an equity beta of 1.00 for both retail and generation in the assessment of electricity pricing[22], clearly well above a beta of 0.80 as chosen by IMO.
- The market observations for beta in the Australian listed companies with generation interests show a range of 0.57 to 1.49, with an average of 0.85. Even with some data points with lower betas, the average is higher than that allowed by the IMO, and the range extends to 1.47.
- The market observations also show gearing levels of 15 per cent to 47 per cent with an average of 24 per cent. The gearing for these energy companies is quite low. The IMO has adopted a gearing of 40 per cent debt which whilst lower than a regulatory assumption for networks of 60 per cent, does not reflect the market observations for generators. The IMO has therefore overestimated the gearing in its calculation of WACC for the MRCP.

[22] IPART – Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity – Final Report dated March 2010

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verve ENERGY

18 December 2012

Independent Market Operator
PO Box 7096
Cloisters Square
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Attention: Greg Ruthven, Manager, System Capacity

Email: imo@imowa.com.au

Dear Greg

INVITATION FOR SUBMISSIONS: DRAFT REPORT – MAXIMUM RESERVE CAPACITY PRICE FOR THE 2015/16 CAPACITY YEAR

Thank you for the opportunity to comment on the Draft Report for the Maximum Reserve Capacity Price (MRCP) for the 2015/16 Capacity Year.

Verve Energy wishes to make the following observation in relation to the methodology used to determine the MRCP.

As part of the submissions process on the Five-Yearly Review of the Methodology and Process for Determining the MRCP (PC_2011_06) Verve Energy noted a concern that the non-inclusion of an adjustment for Forced Outage rates in the MRCP formula could have a serious financial impact, even for plants with a relatively low Forced Outage rates. Verve Energy's full submission on this issue is available on the Independent Market Operator's (IMO) website[1].

In response to this concern the IMO noted that:

> *"...an allowance for Forced Outages should be reconsidered in the future, based on analysis of market data following the implementation of any changes to the Reserve Capacity refund regime, which are expected to be significant..."*[2]

Verve Energy is aware that, as part of the Reserve Capacity Mechanism Working Group's deliberations, there has been an in principle agreement regarding the concept of adopting a dynamic refund mechanism.

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[1] See: www.imowa.com.au/PC_2011_06
[2] Pgs 33 - 34 of 74, Final Procedure Change Report (PC_2011_06).

As such, Verve Energy requests that the IMO add a review of "the potential inclusion of an adjustment for Forced Outages in the MRCP calculation" into its work plan. Verve Energy requests that this review to commence six months after the implementation of a dynamic refund mechanism.

Thank you again for the opportunity to comment. Should you require any additional information please contact me on (08) 9424 1917 or via email at jacinda.papps@verveenergy.com.au.

Yours sincerely

JACINDA PAPPS
SENIOR REGULATORY ANALYST