Independent Market Operator

MRCPWG

Agenda

Meeting No.	9
Location:	IMO Board Room, Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Thursday, 5 May 2011
Time:	Commencing at 3.00 to 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 min
2.	**MINUTES OF PREVIOUS MEETING**	**Chair**	5 min
3.	**ACTIONS ARISING**	**Chair**	5 min
4.	**DETERMINATION OF MARGIN M AND FORWARD ESCALATION FACTORS**	**IMO**	30 min
5.	**ANALYSIS OF SENSITIVITY TO CHANGES TO MRCP METHODOLOGY**	**IMO**	30 min
6.	**DRAFT MARKET PROCEDURE**	**IMO**	30 min
7.	**GENERAL BUSINESS**	**IMO**	5 min
8.	**NEXT MEETING**	**Chair**	5 min

Independent Market Operator

MRCPWG

Minutes

Meeting No.	8
Location:	IMO Board Room Level 3, Governor Stirling Building, 197 St Georges Terrace, Perth
Date:	Thursday 24 March 2011
Time:	Commencing at 3:05 to 5:05pm

Attendees	
Troy Forward	IMO (Chair)
Greg Ruthven	IMO
Monica Tedeschi	IMO
Johan van Niekerk	IMO (Minutes)
Corey Dykstra	Market Customer
Steve Gould	Market Customer
Stephen MacLean	Market Customer
Shane Cremin	Market Generator
Brad Huppatz	Market Generator
Patrick Peake	Market Generator
Pablo Campillos	DSM Aggregator
Neil Gibbney	Western Power
Neil Hay	System Management
Geoff Glazier	Sinclair Knight Merz (SKM) (3:30 – 5:05pm)
Duc Vo	Economic Regulation Authority (ERA (Observer) (3:20 - 4:10pm)
Chris Brown	Economic Regulation Authority (ERA (Observer) (3:50 – 5:05pm)
Apologies	

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the 8th meeting of the Maximum Reserve Capacity Price (MRCP) Working Group (Working Group) at 3:05pm.	
2.	**MINUTES OF PREVIOUS MEETING** The minutes of the 7th MRCP Working Group meeting, held 17 February 2011, were circulated prior to the meeting. They were accepted with a correction to the spelling of Western Power in the	

Item	Subject	Action
	action column on page 3. *Action Point: The IMO to publish Meeting 7 minutes on the website as final.*	**IMO**
3	**ACTION POINTS** Mr Greg Ruthven noted the following actions that were not completed: • AP37: The IMO to initiate a review of the relationship between humidity rates and generator output across a range of locations. This review is still pending. Mr Ruthven confirmed this should be completed in time for the meeting on 5 May 2011. • AP40: Mr Ruthven advised that the Economic Regulation Authority (ERA) had completed its work on an alternative Debt Risk Premium methodology. This would be presented by Dr Duc Vo of the ERA later in the meeting. • AP43: SKM and Western Power had exchanged data regarding Transmission Connection Costs and the results would be presented by SKM later in the meeting. • AP47/52: It was confirmed that Worley Parsons had been appointed, subject to agreement of terms and conditions, to undertake the exercise to independently provide a Margin M calculation and a view on forward-looking cost escalation factors. As Mr Geoff Glazier was yet to arrive it was agreed that the discussion of the SKM Research Report would be delayed till later in the meeting.	
4	**SUBMISSIONS FROM 2011 MRCP DETERMINATION** Mr Ruthven noted the comments received with regards to escalation factors. As previously noted it was anticipated that the Worley Parsons report would be available for the next meeting to allow further consideration of this component. With regards to volatility in the MRCP, Mr Ruthven confirmed that this subject would form part of the final discussions of the Working Group. Mr Ruthven detailed the comments received in respect of allowances for insurance costs in the MRCP, for the period after commencement of plant operation. After some discussion it was agreed that there was validity in classing insurance expenses as a fixed cost and that the IMO should investigate the components of insurance costs during plant operation and calculate a variable for inclusion in future MRCP calculations. *Action Point: The IMO to include ongoing insurance costs for the period following plant construction within the fixed O&M component in future MRCP calculations.* Mr Ruthven detailed the physical restrictions with regards to minimum land size available at certain locations which conflicted somewhat with the MRCP Procedure. It was agreed that for future MRCP calculations that the land size used would continue	 **IMO**

Item	Subject	Action
	to be 3 hectares but where the minimum land size able to be purchased at any specific location was more than 3 hectares that that minimum specific land size would be used for the calculation of a MRCP price for that specific location. *Action Point: The IMO to amend the Market Procedure to incorporate variability of land size when determining the Land Cost for locations where 3 hectare blocks are unavailable.* Mr Ruthven detailed the comments received regarding the capitalisation period (currently 15 years) used in determining the MRCP. Mr Corey Dykstra stated that there was a potential mismatch between the 15 years used for capitalisation of expenses versus an economic life for plant of potentially 30-40 years. He outlined the potential for the MRCP in its current form to over-compensate investors. Mr Stephen MacLean stated that power generation technology was continuing to develop and that this represented potential risks to current plant viability as new technology had the potential to make current plant comparatively less efficient. Mr MacLean stated that despite the potential for developments in this area to potentially reduce future investment returns for current technology, Open Cycle Gas Turbines (OCGT) could be re-located if it made economic sense to do so. In addition Mr Patrick Peake detailed that there were substantial maintenance cost implications for OCGT plants after 15 years, where complete re-builds of parts of a plant might be required. Mr Pablo Campillos voiced his concern that there continued to be real risks that plant could become obsolete in the future and that any lengthening of the capitalisation period should take into account these risks. Mr Peake mentioned fuel cells as having real potential to impact on OCGT viability in the future. It was noted that even taking into account consideration of plant obsolescence and maintenance that a lengthening of the capitalisation period would most likely result in a lower MRCP determination. Mr Neil Gibbney questioned as to whether a lengthening of the capitalisation period and likely reduction in the MRCP might significantly reduce the attractiveness of new investment. Mr MacLean suggested that increased competition in the market might encourage an acceptance of a longer capitalisation period. Mr Peake advised that over a long term investment, the variability in MRCP represented a significant risk for investors and that bank finance would be more difficult to obtain if the capitalisation period was increased resulting in an expected reduction in capacity-based income. This might lead to significant funding issues for investors in new capacity. The Chair proposed that the IMO should investigate the issues discussed and formulate a view on the impact of lengthening the capitalisation period taking the issues into account under a number of possible scenarios. The Group agreed that the IMO should perform an investigation as discussed. *Action Point: The IMO to investigate the issues surrounding a change in the capitalisation period, and the impact on the MRCP, and present the results at the meeting on 5 May 2011.*	**IMO** **IMO**

Item	Subject	Action
5	**WEIGHTED AVERAGE COST OF CAPITAL - DEBT RISK PREMIUM** The Chair introduced Dr Vo from the ERA to make a presentation on the ERA bond-yield approach to calculating a Debt Risk Premium (DRP), as published in the ERA's Final Decision on WA Gas Networks (WAGN). The presentation is attached as Appendix A. Mr Dykstra commented that while the ERA approach may have some validity it was not as yet recognised as a valid approach and that the Australian Competition Tribunal would be reviewing the methodology as used with particular reference to its consistency with national gas laws. Mr Vo advised that a similar methodology to that proposed by the ERA had been accepted and utilised in New Zealand over the last 5-7 years. Mr Ruthven advised that it was likely that the appeal process would be finalised by the end of 2011. Mr Dykstra suggested that until there was clarity there was validity in continuing to use the current methodology, in the absence of a valid and accepted alternative. Mr Dykstra proposed that the MRCP Procedure should allow some flexibility in the methodology used in calculating the DRP and at this stage, until clarification had been obtained, the IMO should still be have the option to use the current methodology. The Chair proposed that the IMO should also undertake a sensitivity analysis to estimate the impact on the MRCP of any change from the use of the current methodology to that proposed by the ERA. The Group agreed that the IMO should perform the sensitivity analysis and present the results at the next meeting. *Action Point: The IMO to investigate the issues surrounding a change in the DRP calculation methodology, and the impact on the MRCP, and present the results at the meeting on 5 May 2011.*	**IMO**
6	**DEEP CONNECTION COSTS – RESEARCH REPORT** Mr Glazier provided a detailed summary of the content of the Research Report including assessment criteria used for methodology selection, market objectives and related criteria, issues in defining Deep and Shallow Connection Costs and an audit of the Western Power process. It was confirmed, as previously agreed, that the preferred methodology was based on actual historical connections costs with access offers from the current year. Mr Glazier confirmed that there was a limited data set which presented some challenges but that this methodology had a more representative data set than the current methodology. Mr Glazier noted that the data provided wasn't necessarily uniform in that some costs were included in some data points used while others were not. This would be the case where a	

Item	Subject	Action
	measure of Total Connection Costs (TCC) for a project did not include transmission connection costs borne directly by the Customer whereas these costs might be charged to the Customer by Western Power for other projects. It was noted that before finalising the report there would be an audit and cleanup of data. Mr Glazier confirmed that the only significant change from the previous report was the inclusion of the trend graph following the update of the model with data by Western Power. He confirmed that some verification was still required but that the trend graph was reflective of the data provided. Mr Glazier confirmed that the proposed methodology produced a TCC of $127,000 per MW compared to $305,000 per MW in the 2011 MRCP under the current methodology, representing a 58% decline in connection costs. It was confirmed that actual TCC for the last 5 years were maintained in the calculation with a greater weighting given to more recent periods. In addition access offers, for the current year, were utilised in the calculation of TCC. It was confirmed that access offers would be used in the calculation of TCC only for the current year with access offers from previous years not included in the calculation. Mr Glazier stated that the forecast for TCC was based on what was actually happening in the market with some participants finding innovative solutions to connect to the system in a cost efficient manner. It was noted that despite any issues with sample size, which was relatively small, that this represented a superior methodology than currently employed which depended on more limited data. Mr Peake questioned as to whether potential new entrants had any knowledge of efficient locations, with regards to TCC, to build new capacity and that this may lead to a disconnection between the model and actual connection costs for less opportunistic new capacity. Mr Gibbney stated that the data generated was based on very opportunistic access to the system and that future capacity growth might be hindered if the MRCP was not high enough. In addition he stated that the calculation generated by the proposed methodology of $127,000 per MW was not comparable with the estimated replacement cost of the total Western Power network of $600,000 per MW. Mr Glazier confirmed the objective of the model in this regard was to reflect an efficient marginal position. The Group agreed the proposed methodology, based on historical costs with current access offers, should be adopted with Western Power and SKM to complete any cleanup of data and finalise the report for the next meeting. *Action Point: Western Power and SKM to complete any cleanup of data, and SKM to finalise the Research Report.* In addition it was agreed that the IMO should investigate the likely	**Western Power/SKM** **Western Power/SKM**

Item	Subject	Action
	impact of the proposed change in the TCC calculation methodology and the impact of any change on the MRCP. *Action Point: The IMO to investigate the issues surrounding a change in the TCC calculation methodology, and the impact on the MRCP, and present the results at the meeting on 5 May 2011.*	**IMO**
5	**GENERAL BUSINESS** Mr Chris Brown advised that he had a number of queries regarding the draft Market Procedure which he would forward via email, following the meeting. It was agreed that Members should forward any comments outside of the meeting. *Action Point: Any comments regarding the proposed MRCP Procedure to be forwarded via email to the IMO.*	**All**
6	**NEXT MEETING** Mr Ruthven noted that the next meeting would be held on Thursday 5 May 2011. It was agreed that depending on the nature of business to be discussed it might be necessary to allocate three hours for the meeting. Mr Ruthven confirmed that he would confirm this with prospective attendees closer to the next meeting date. *Action Point: Mr Ruthven to advise prospective attendees of the meeting details closer to the next meeting date.*	**IMO**
7	**CLOSED:** The Chair declared the meeting closed at 5:05 pm.	

Agenda Item 3: MRCPWG - Action Points

Legend:

Unshaded	Unshaded action points are still being progressed.
Shaded	Shaded action points are actions that have been completed

#	Meeting Arising	Responsibility	Action	Status/Progress
37	Meeting 5	IMO	The IMO to initiate a review of the relationship between humidity rates and generator output across a range of locations.	Pending.
40	Meeting 6	ERA / IMO	ERA to provide details of proposed alternative Debt Risk Premium methodology to IMO.	Completed. Presented at Meeting 8.
43	Meeting 6	SKM / Western Power	SKM and Western Power to discuss data availability in order to supply data to SKM with a view to further investigating option 2 (Forecast DCC based on Historic Connection Costs Data).	Completed.
47	Meeting 7	IMO	IMO to engage an engineering consultant to undertake an exercise to independently provide a Margin M calculation for comparison purposes.	WorleyParsons engaged to provide report. Expected that report will be available for distribution prior to meeting.

#	Meeting Arising	Responsibility	Action	Status/Progress
52	Meeting 7	IMO	IMO to engage an engineering consultant to independently provide a view on forward-looking cost escalation factors.	WorleyParsons engaged to provide report. Expected that report will be available for distribution prior to meeting.
54	Meeting 8	IMO	IMO to publish Meeting 7 minutes on the website as final.	Completed.
55	Meeting 8	IMO	IMO to include ongoing insurance costs for the period following plant construction within the fixed O&M component in future MRCP calculations.	Completed. Inclusion of insurance costs has been added to draft Market Procedure for consideration at Meeting 9.
56	Meeting 8	IMO	IMO to amend the Market Procedure to incorporate variability of land size when determining the Land Cost for locations where 3 hectare blocks are unavailable.	Completed. Added to draft Market Procedure for consideration at Meeting 9.
57	Meeting 8	IMO	IMO to investigate the issues surrounding a change in the capitalisation period and the impact on the MRCP, and present the results at the 5 May 2011 meeting.	Completed. Discussion paper to be considered at Meeting 9.
58	Meeting 8	IMO	IMO to investigate the issues surrounding a change in the DRP calculation methodology and the impact on the MRCP, and present the results at the 5 May 2011 meeting.	Completed. Discussion paper to be considered at Meeting 9.
59	Meeting 8	SKM / Western Power	Western Power and SKM to complete any clean-up of data, and SKM to finalise the Research Report.	Pending. Final Report pending finalisation of data between Western Power and SKM.
60	Meeting 8	IMO	IMO to investigate the issues surrounding a change in the Total Connection Cost calculation methodology and the impact on the MRCP, and present the results at the 5 May 2011 meeting.	Completed. Discussion paper to be considered at Meeting 9.
61	Meeting 8	MRCPWG Members	Members to provide any comments regarding the draft MRCP Market Procedure to the IMO via email.	Completed. No comments received.

Agenda Item 4: Independent Report on Margin M and Escalation Factors

1. BACKGROUND

It was agreed at the meeting on 17 February 2011 that:

- Sinclair Knight Merz (SKM) would be requested to provide a brief synopsis behind the methodology that it uses for determining each component of the margin M; and
- the IMO would engage an engineering consultant to provide an independent view on margin M and the escalation factors used in the MRCP calculation. Following a request for quotations, WorleyParsons was appointed to perform the exercise.

The following documents are provided as Appendices to this paper:

- the report from WorleyParsons is provided as Appendix A;
- the report from SKM describing its methodology for determining the margin M (provided previously for Meeting 8) is provided as Appendix B; and
- the report from SKM describing its proposed methodology for forward-looking cost escalation factors (previously provided for Meeting 7) is provided as Appendix C.

2. MARGIN M

WorleyParsons has reviewed the methodology employed by SKM in determining the margin M and found that:
"*The components of term M provided in SKM's 2010 report appear to include all the non-EPC costs associated with the power station. The values for the individual components may vary but the overall value of term M is in the range expected for a 160MW open cycle power station.*"

WorleyParsons also reviewed the individual components to assess whether they were more appropriately considered as a percentage of the power station capital cost (as the margin M is currently determined and applied) or as a flat cost. It found that the magnitude of several components is largely independent of the power station capacity and recommends that these be handled separately as a separate flat cost within the MRCP calculation.

The IMO has separately discussed this matter with SKM. SKM has advised that its method focuses on projects of approximately 160 MW. It normalises the prices from historical projects in estimating the component costs for margin M, and the dependence or independence between the component costs and the power station capacity are accounted for in this process.

Consequently, the IMO recommends that the current methodology for determining the margin M be retained.

3. ESCALATION FACTORS

The IMO notes that the costs that it gathers for the various components of the theoretical power station are typically referenced to June in the year prior to the commencement of the Reserve Capacity Cycle. Previously these costs have been escalated forward by one year to June in Year 1 of the Reserve Capacity Cycle. This provides some consistency with the previous application of the WACC, which assumed that the costs would be incurred by the project developer two years before the payment stream was realised.

The IMO also notes that the MRCPWG previously agreed to implement Pricewaterhouse Coopers' recommendation to amend the application of the WACC to consider that the costs are incurred, on average, six months before the payment stream was realised. This change necessitates that input costs be escalated forward to this date. For the example of the recently completed MRCP determination for the 2013/14 Capacity Year, input costs referenced to June 2010 would need to be escalated forward to April 2013.

The escalation factors used in previous MRCP determinations have projected costs forward using historical price movements. Submissions during the most recent MRCP determination questioned the validity of this approach. Consequently, the IMO has investigated alternative escalation factor methods with the aim of selecting a method that is robust, transparent and simple to implement.

SKM has proposed the development of forward escalation factors that are based on a weighted average of forecast movements in CPI and the prices of labour, steel, copper and cement. A description of these base indices follows:

- CPI based on Reserve Bank forecasts from the *Statement of Monetary Policy*;
- Labour escalators (national and WA) based on extrapolation of historical ABS wage price indices;
- Copper escalator based on daily spot and futures pricing from the London Metal Exchange (LME);
- Steel escalator from Consensus Economics forecasts of Hot Rolled Coil steel pricing; and
- Cement escalator from the Construction Forecasting Council forecasts of engineering construction costs.

The IMO notes that SKM has applied this method in submissions to the Australian Energy Regulator (AER) for predicting future movements in transmission and switchyard construction costs. SKM has developed the weighting factors for the various base indices over a number of years (e.g. a transmission line development may require xx% steel, xx% copper, etc.). The costs of these works are transparent as they are often undertaken by regulated businesses.

However, the costs for power station development are less transparent and the weighting factors for escalating these costs have not been refined over a number of years. The IMO considers that this process is not yet sufficiently developed or robust for implementation in the MRCP determination.

WorleyParsons has listed a range of historical ABS indices for escalating costs and has proposed the following options for escalation:

1. use of the ABS indices from the previous 12 months;
2. linear regression of the ABS indices to predict future price movements, which would provide a more stable outcome; or
3. the CPI and Wage Price Index forecasts from the State Budget papers.

The IMO considers that there is value in moving to an escalation methodology that considers future expectations of economic conditions. However, the IMO does not consider that the method recommended by SKM is sufficiently robust for use in escalating all of the component costs. Also, the use of historical ABS indices would not consider any future expectations.

The IMO recommends that cost escalation be performed using a combination of CPI forecasts and Wage Price Index forecasts. For consistency with the inflation parameter in the Weighted Average Cost of Capital, the IMO recommends that the CPI forecast be sourced from the Reserve Bank *Statement on Monetary Policy*, while the Wage Price Index forecasts be sourced from the State Budget papers. The IMO notes that power station-related cost movements may deviate from these indices but considers that this method is transparent, simple and predictable.

If endorsed by the MRCPWG, the IMO will determine appropriate weightings of these indices for use in escalating the different component costs of the MRCP.

4. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Note** the IMO's recommendation to retain the current methodology for determination of margin M; and
- **Note** the IMO's recommendation to escalate costs using CPI and Wage Price Index forecasts.

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INDEPENDENT MARKET OPERATOR

Maximum Reserve Capacity Price

Review of Term M and Escalation

101012-00310 – 101012-00310-G-001

3 May 2011

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PROJECT 101012-00310 - MAXIMUM RESERVE CAPACITY PRICE

REV	DESCRIPTION	ORIG	REVIEW	WORLEY-PARSONS APPROVAL	DATE	CLIENT APPROVAL	DATE
A	Issued for internal review	S Haddon		N/A	14 April 2011	N/A	
B	Draft For Client	S Haddon	A Piccinini		3 May 2011		

CONTENTS

1 INTRODUCTION

The Independent Market Operator (IMO) administers and operates the wholesale electricity market within the South West Interconnected System in accordance with the Market Rules. The Market Rules require the IMO to review and set the Maximum Reserve Capacity Price (MRCP) each year.

The IMO's procedure for determining the MRCP includes a term "M" which is defined as "a margin to cover legal, approval and financing costs and contingencies." The term "M" is used to account for development costs expected to be incurred and is applied as a percentage of the capital cost.

IMO commissioned WorleyParsons to review whether term "M" should be applied as a percentage of the capital cost or whether it should be applied as a fixed dollar amount and to provide a view on the magnitude of term M.

In addition, IMO requested WorleyParsons to develop and propose a methodology for the escalation of capital and operating costs for power station and transmission connection assets.

2 MARGIN "M"

Section 1.14 of the IMO's Market Procedure for Determination of the Maximum Reserve Capacity Price version 1.1 (the Market Procedure) defines the term 'M' as "a margin to cover legal, approval, and financing costs and contingencies." IMO requested WorleyParsons to provide advice as to whether margin "M" should be included in the MRCP as a percentage of capital or as a fixed dollar amount subject to escalation.

The SKM report; Review of the Maximum Reserve Capacity Price 2010 – Power Station Elements; includes a table of term M components (reproduced as Table 2-1 below) as a percentage of the total EPC cost for a generic 160 MW open cycle gas turbine power station. It is generally accepted that the components of term M defined in Table 2-1 are expressed as a percentage of EPC cost. This is done as both a "sanity check" on the estimate and as a quick estimating method. However, to determine a +/- 10 % cost estimate, estimating standards require detailed estimates and/or multiple prices for the components of term M to be obtained and included as part of the estimate. These costs may then be converted to a percentage of the EPC cost.

There is risk in using a percentage cost for the components of term M derived in one year to estimate the cost in future years and applying the percentages to plant with different capacity. This is particularly true for periods where exchange rates and commodity prices are volatile.

Table 2-1 - Components of Term M

Component of 'M'	**% of Total EPC**
Project Management	1.9%
Project Insurance	1.5%
Contingencies	5.0%
Cost of Raising Capital	4.0%
Environmental Approvals	0.7%
Legal Costs	1.2%
Owners Engineers - Part A (Including concept design, specification, tendering, contract negotiations)	0.4%
Owners Engineers - Part B (Including Construction Phase OE Costs, oversee project, witness tests & Commissioning)	3.0%
Initial Spares requirements	0.8%
Site Services (Provision of potable water, construction power, communications, domestic sewerage etc. at site)	0.1%
Total M as a percentage of CAPEX	**18.6%**
Multiplier in CAPEX equation 2	**(1 + 0.186)**

The components of term M provided in SKM's 2010 report appear to include all the non EPC costs associated with the power station. The values for the individual components may vary but the overall value of term M is in the range expected for a 160 MW open cycle power station. Table 2-2 provides comments on the individual components of term M based on recent experience.

Table 2-2 – Value of the Components of Term M

Components of 'M'	% of Total EPC	Calculated Cost ('000)	Recent typical experience	Comments
Project Management	1.9%	$ 2,314		Within the expected range
Project Insurance	1.5%	$ 1,827	$ 1,000	All our experience is with lower insurance costs however we allow some project insurance (primarily for transport) in the EPC contracts. That may account for the difference.
Contingencies	5.0%	$ 6,090		On the low end of the expected range. Varies based on how well defined the project is.
Cost of Raising Capital	4.0%	$ 4,872	$3,500 - $4,000	This figure appears conservative for a relatively small project. Assume a total funding requirement for the project of around $140m with $100m debt and a requirement to raise half of the remaining equity. We would allow 2.5% – 3% of the debt amount ($2.5m - $3.0m) and 4% of the equity requirement ($1m). If the SKM figure includes interest during construction it is reasonable.
Environmental Approvals	0.7%	$ 852	$2,000 - $3,000	Environmental approvals, development approvals and licensing are complex questions requiring

				considerable upfront investigation and we would expect significantly higher costs that set out here.
Legal Costs	1.2%	$ 1,461	$1,000 - $3,000	Legal costs are a function of risk. The estimate of $1,461 is within a normal range for provision of legal services.
OE1 (Concept, Spec, Tendering, Negotiations)	0.4%	$ 487	$1000	The cost of engineering is a function of how well the project is defined up front and will impact on the contingency requirement.
OE2 (Construction OE roles)	3.0%	$ 3,654		
Initial Spares	0.8%	$ 974		
Site Services (construction power, water etc.)	0.1%	$ 121		
	18.6%	$22,655		

In considering whether the components of term M should be defined as a percentage of the power station EPC cost or as a fixed dollar figure, each component should be assessed as to whether the component is actually related to the EPC cost or is independent of EPC cost. In addition, the magnitude of each component relative to the overall cost should be considered.

Table 2-3 shows which components of term M are related to the total EPC cost for the power station.

2.1 Legal Costs

Legal costs do not typically vary in relation to capital value. They are more related to the risk preferences of the investor, the complexity of equity & debt funding arrangements, the type of procurement contract/s and the complexity of those contracts, the complexity of fuel supply and transportation arrangements and the complexity of any offtake agreement.

Therefore it is considered inappropriate to express the legal costs as a percentage of the capital cost of the project. A fixed provision escalating with relevant market drivers in the legal/consultancy services market would be more appropriate.

2.2 Financing Costs

Unlike legal costs the financing costs not directly covered in the application of the cost of finance typically include both fixed and variable elements. The fixed components tend to cover minimum costs for establishment of the financing arrangements and the variable costs are based on the quantum of financing (including or incorporating success fees). The costs also tend to reflect a reducing percentage with project size and therefore higher financing requirements will result in a lower percentage cost. However, that aspect is less relevant in the circumstance where the IMO is considering the same sized plant each year.

Therefore, for a significant project such as a 160MW OCGT which could be expected to cover a minimum fee comfortably, it would be appropriate to include a fee which reflects a percentage of capital cost which in turn reflects the debt and/or equity requirements.

2.3 Insurance Costs

Insurance costs are established based on factors associated with the risk of incurring an insurance event. For the situation where a standard sized OCGT is being considered a majority of project risk factors are essentially fixed for the project and therefore insurance costs will essentially vary with the value of the plant being insured. Therefore it is considered appropriate to base the insurance costs on a percentage of the capital cost of the project.

2.4 Approval Costs

Like legal costs the cost of environmental approvals and government licensing and planning approvals is predominantly related to the effort involved in preparing documentation, managing the process and investigating/signing off relevant issues. Therefore the cost will not be vary in relation to capital value but should reflect a fixed cost typical of similar sized projects. Costs will vary more with the complexity of the approvals process and particular sensitivities for the proposed location.

It is therefore considered more appropriate to include a fixed cost provision escalating with relevant market drivers in the environmental/consultancy services market.

2.5 Engineering Costs

The engineering costs associated with an open cycle 160 MW gas turbine based power station are independent of the power station capital cost and are not directly scalable with varying power station capacity. It takes nearly as much engineering for an 80 MW plant as it does for a 160 MW plant.

It is therefore considered more appropriate to include a fixed cost provision escalating with relevant market drivers in the environmental/consultancy services market.

2.6 Contingency

Contingency is generally expressed as a percentage of the capital cost, however the contingency should be a calculated number based on a risk assessment of the cost estimate components. For a +/- 10% cost estimate the contingency should be in the 5% - 10% range.

Table 2-3 - Component / EPC Relationship

Component of 'M'	Relationship to EPC Price
Project Management	Not Related
Project Insurance	Related
Contingencies	Related
Cost of Raising Capital	Related
Environmental Approvals	Not Related
Legal Costs	Not Related
Owners Engineers - Part A (Including concept design, specification, tendering, contract negotiations)	Not Related
Owners Engineers - Part B (Including Construction Phase OE Costs, oversee project, witness tests & Commissioning)	Not Related
Initial Spares requirements	Related
Site Services (Provision of potable water, construction power, communications, domestic sewerage etc. at site)	Not Related

Of the components of term M listed in Table 2-1, approximately 40% are not directly related to the EPC cost of a 160 MW open cycle gas turbine plant. It could be argued that these components should be calculated to provide a dollar figure that would be escalated from a base date rather than being quoted as a percentage of the EPC cost.

The term M is used in the following calculation to derive the capital cost.

"CAPCOST[t] = (PC[t] x (1 + M) x CAP + TC[t] + FFC[t] + LC[t]) x (1+ WACC)^2

Where:

PC[t] is the capital cost of an open cycle gas turbine power station in year t, expressed in Australian dollars in year t per MW;

M is a margin to cover legal, approval, and financing costs and contingencies;

CAP is the power station capacity in MW;

TC[t] is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS, plus an estimate of the costs of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station, expressed in Australian million dollars in year t;

FFC[t] is the fixed fuel costs and must represent the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times expressed in Australian million dollars in year t;

LC[t] is the cost of land purchased in year [t]; and

WACC is the Weighted Average Cost of Capital."

In the calculation of CAPCOST[t], term M is multiplied by the capital cost derived from $/MW multiplied by the power station capacity. If the power station capacity is say 80MW for example the non EPC related components of term M could be up to 100% in error. This is because the management, engineering, legal, environmental and site services costs are approximately the same regardless of the capacity of the power station.

For a generic 160 MW OCGT power station the non EPC related components of term M equate to approximately 6% of the power station development cost (EPC cost * (1+M)) based on the breakdown shown in Table 2-1. This is within the bounds of the estimate accuracy particularly given the broad assumptions made in developing the capital cost estimate. There are items excluded from the capital cost estimate due its generic nature that could result in costs well in excess of the non EPC related components of term M. Thus the absolute value of the non EPC related components of term M may become insignificant.

Although the non EPC related components are not material to the overall accuracy of the value of term M, it is recommended that they be included as a fixed amount that is escalated annually based on appropriate indexes to more accurately reflect costs associated with variation in plant size.

3 ESCALATION

IMO requested WorleyParsons to develop a proposed methodology for the calculation of escalation factors, including any weightings where applicable, for use in escalating (in October of year N) costs from June in year N up to June in year N+1 of:

a) The power station capital cost (engineering, procurement, installation and commissioning, excluding land cost) in respect of a model 160MW Open Cycle Gas Turbine (single liquid fuel) power station.

b) Fixed Operating and Maintenance (O&M) costs of the above facility with capacity factor of 2%.

c) The capital costs (procurement, installation and commissioning, excluding land cost) of a generic 330 kV switchyard.

d) The capital costs (procurement, installation and commissioning, including shallow land easement cost) of a 2km, 330kV transmission line.

e) Fixed O&M costs in respect of switchyard and transmission assets.

The objective of the escalation methodology is to provide a transparent means of estimating the future capital cost of power station and transmission connection assets.

The influence of variation to exchange rates is included in ABS indexes therefore no allowance is required for changes in exchange rates.

3.1 Escalation Methodology

The objective of the escalation methodology is to estimate the future cost of the power assets in an objective, transparent manner. The methodology and any indices used should be agreed with relevant stakeholders.

Escalation forecasts will generally use historic data and extrapolate to the future. The further into the future the data is extrapolated the less accurate it becomes.

One methodology for forecasting is to select relevant indexes and use a linear regression through past values. The future value is estimated using the result of the regression. This method will provide a fairly consistent, stable annual escalation that will have little variation even if one year has large changes in commodity prices and exchange rate changes.

It is also possible to use historic annual index changes as the tool to forecast future prices. This method will follow the market but will lag behind the actual pricing by at least one year.

The Western Australian Government provides a forecast for CPI and Labour. The use of this data would also create a transparent method for future pricing but would not necessarily reflect the power market.

The following sections identify indexes from the Australian Bureau of Statistics that are applicable to power assets and the proportion of the EPC price applicable to those indexes. The change in indices for the June 2009 to June 2010 period is provided to compare with previous MRCP reports.

3.2 Power Station Capital Cost

The Review of Maximum Reserve Capacity Price 2010 – Power Station Elements written by Sinclair Knight Merz provides a capital cost estimate for a generic 160MW open cycle gas turbine power station and is reproduced in Table 3-1 below.

Table 3-1 - Generic 160MW OCGT capital cost estimate

Item		Cost ($)
1	Main Plant Equipment	$ 79,000,000
2	Balance of Plant	$ 2,900,000
3	Civil Works	$ 10,700,000
4	Mechanical Works (including installation)	$ 9,000,000
5	Electrical Works (including installation)	$ 2,500,000
6	Buildings	$ 1,900,000
7	Engineering & Plant Start-up	$ 3,900,000
8	Contractor's Costs	$ 11,900,000
Total EPC Cost		$121,800,000

Table 3-2 provides a list of the EPC cost components, the percentage of the EPC cost for each component and the Australian Bureau of Statistics (ABS) index reference chosen. The majority of the main plant equipment will be imported hence the imported final commodities index was selected.

The use of ABS indexes provides a transparent method of adjusting the EPC cost for the power station. However it should be recognized that the indexes may not immediately reflect or may lag price changes due to market forces on a particular piece of equipment.

Table 3-2 – Power Station Component Breakdown and Indexes

Item	EPC Component	% cost of EPC	Index Reference
1	Main Plant	64.9	Source: Producer Price Indexes, Australia (ABS

Item	EPC Component	% cost of EPC	Index Reference
	Equipment		Catalogue 6427.0, Table 7) Index Numbers ; 285 Electrical equipment and appliance mfg
2	Balance of Plant	2.4	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 7) Index Numbers ; 285 Electrical equipment and appliance mfg
3	Civil Works		
3a	Civil work material	2.6	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 16 & 17) Index No: Concrete, cement and sand; Perth
3b	Civil work labour	6.1	Source: Labour Price Index, Australia (ABS Catalogue 6345.0) Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series A2705992V
4	Mechanical Works		
4a	Mechanical material	2.2	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 12 and 13) Index Numbers: Fabricated Metal Products
4b	Mechanical labour	5.2	Source: Labour Price Index, Australia (ABS Catalogue 6345.0) Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series A2705992V
5	Electrical Works		
5a	Electrical material	0.5	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 12 and 13) Index Numbers: Electrical equipment
5b	Electrical labour	1.5	Source: Labour Price Index, Australia (ABS Catalogue 6345.0) Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series A2705992V

Item	EPC Component	% cost of EPC	Index Reference
6	Buildings	1.6	CPI
7	Engineering & Plant Start-up	3.2	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 22) Index Numbers ; 6923 Engineering design and engineering consulting services
8	Contractor's Costs	9.8	CPI

The indexes in Table 3-2 are applied to the percentage capital and the results summed to provide an overall percentage change. The indexes as applied for the period June 2009 to June 2010 are provided in

Table 3-3 and shows a change in EPC cost for the period of -7.18%. The change is driven by the major plant items which will be imported. The index applied to these items also accounts for exchange rate changes which were significant during the period.

It is noted that SKM's report; Review of the Maximum Reserve Capacity Price 2010 – Power Station Elements, showed an increase in the EPC cost of approximately 2.2%. The reasons for the discrepancy are not certain but are within the accuracy range cited by SKM.

Applying a linear regression methodology for the period from 2005 to 2010 will result in an escalation of approximately 3%.

The most appropriate and accurate way to develop EPC price and monitor the price movement is to complete comprehensive cost estimates including obtaining actual equipment pricing and then re-validating that estimate annually. The cost may be escalated to future years using CPI or another appropriate index but must be re-validated each year.

Table 3-3 - 2009/2010 Power Station Index

Item	Description	% of EPC	2009 Index	2010 Index	Index % Change	EPC % Change
1	Main Plant Equipment	64.9	4.09	3.63	-0.11	-7.30
2	Balance of Plant	2.4	4.09	3.63	-0.11	-0.27
3	Civil Works					
3a	Civil work material	2.6	170.3	168.4	-0.01	-0.03
3b	Civil work labour	6.1	100	103	0.03	0.18
4	Mechanical Works					

Item	Description	% of EPC	2009 Index	2010 Index	Index % Change	EPC % Change
4a	Mechanical material	2.2	150.9	124.5	-0.17	-0.38
4b	Mechanical labour	5.2	100	103	0.03	0.16
5	Electrical Works					
5a	Electrical material	0.5	105	104.8	0.00	0.00
5b	Electrical labour	1.5	100	103	0.03	0.05
6	Buildings	1.6	167.4	173.2	0.03	0.06
7	Engineering & Plant Start-up	3.2	189.4	191	0.01	0.03
8	Contractor's Costs	9.8	167.4	173.2	0.03	0.34
				Total % change in EPC Price		-7.18

3.3 Power Station Fixed Operating and Maintenance Cost

The SKM report; Review of the Maximum Reserve Capacity Price 2010 – Power Station Elements; provides an estimate for the power station fixed operating and maintenance costs including the assumptions associated with the estimate. The fixed operating costs for a power station with a capacity factor of 2% consist primarily of:

- Labour – 50%
- Licencing and fees – 10%
- Corporate overheads – 10%
- Other – 30%

It is proposed that the labour component be escalated based on the WA labour index and the remainder be escalated based on CPI based on the relative percentages of each component.

3.4 Switchyard Capital Cost

The switchyard capital cost has been developed by SKM in its report Review of the Maximum Reserve Capacity Price 2010 – Non Power Station Elements for 2010. The estimated switchyard cost is $11,504,234. An approximate percentage breakdown of the cost is provided in Table 3-4. Also included in Table 3-4 is the proposed index for each component.

Table 3-4 - Switchyard Component Breakdown and Indexes

Item	Component	% of total cost	Index Reference
1	Earthworks material	6	Source: Price index of materials used in house building, By material–Perth (ABS Catalogue 13675, Table 4) Index No: Concrete, cement and sand
2	Concrete material	4	Source: Price index of materials used in house building, By material–Perth (ABS Catalogue 13675, Table 4) Index No: Concrete, cement and sand
3	Steel	1	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 12 and 13) Index Numbers: Fabricated Metal Products
4	Electrical equipment	25	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 7) Index Numbers ; 285 Electrical equipment and appliance mfg
5	Labour	56	Source: Labour Price Index, Australia (ABS Catalogue 6345.0) Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series A2705992V
6	Engineering & Project Management services	8	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 22) Index Numbers ; 6923 Engineering design and engineering consulting services

Application of the indexes to the switchyard components for the period June 2009 to June 2010 is shown in Table 3-5 and indicates a decrease in the EPC price of 1.35%.

Table 3-5 - 2009/2010 Switchyard Index

Item	Description	% of EPC	2009 Index	2010 Index	Index % Change	EPC % Change
1	Earthworks material	6	170.3	168.4	-0.01	-0.07
2	Concrete material	4	170.3	168.4	-0.01	-0.04
3	Steel	1	150.9	124.5	-0.17	-0.17
4	Electrical equipment	25	4.09	3.63	-0.11	-2.81
5	Labour	56	100	103	0.03	1.68
6	Engineering & Project Management services	8	189.4	191	0.01	0.07
				Total % change in EPC Price		-1.35

3.5 Transmission Line Capital Cost

The transmission line cost has been developed by SKM in its report Review of the Maximum Reserve Capacity Price 2010 – Non Power Station Elements for 2010. The estimated transmission line cost is $2,245,886. An approximate percentage breakdown of the cost is provided in Table 3-6. Also included in Table 3-6 is the proposed index for each component. Note that an escalation component for easement costs has not been included primarily because easement costs are so variable.

Table 3-6 - Transmission Line Component Breakdown and Indexes

Item	Component	% of Total Cost	Index Reference
1	Fabricated Steel	30	Source: Producer: Price Indexes, Australia (ABS Catalogue 6427.0, table 10) Index Numbers: 2221 Structural steel fabricating
2	Aluminium	10	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 10) Index Numbers ; 2142 Aluminium rolling, drawing, extruding
3	Concrete	10	Source: Price index of materials used in house building, By material–Perth (ABS Catalogue 13675, Table 4) Index No: Concrete, cement and sand
4	Other Material	7	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 7) Index Numbers ; 285 Electrical equipment and appliance mfg
5	WA Labour	35	Source: Labour Price Index, Australia (ABS Catalogue 6345.0) Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series A2705992V
6	Engineering & Project Management services	8	Source: Producer Price Indexes, Australia (ABS Catalogue 6427.0, Table 22) Index Numbers ; 6923 Engineering design and engineering consulting services

Application of the indexes to the switchyard components for the period June 2009 to June 2010 is shown in Table 3-7 and indicates a decrease in the EPC price of 5.17%.

Table 3-7 2009/2010 Transmission Line Index

Item	Description	% of EPC	2009 Index	2010 Index	Index % Change	EPC % Change
1	Fabricated Steel	6	223.5	190.1	-0.15	-4.48
2	Aluminium	4	131.8	119.9	-0.09	-0.90
3	Concrete	1	170.3	168.4	-0.01	-0.11
4	Other Material	25	4.09	3.63	-0.11	-0.79
5	WA Labour	56	100	103	0.03	1.05
6	Engineering & Project Management services	8	189.4	191	0.01	0.07
				Total % change in EPC Price		-5.17

3.6 Fixed Operating and Maintenance Costs for Switchyard and Transmission Assets

The SKM report; Review of the Maximum Reserve Capacity Price 2010 – Non Power Station Elements; provides an estimate for the switchyard and transmission line fixed operating and maintenance costs including the assumptions associated with the estimate. The fixed operating costs consist primarily of:

- Labour – 20%
- Licencing and fees (including network connection) – 70%
- Other – 10%

It is proposed that the labour component be escalated based on the WA labour index and the remainder be escalated based on CPI. It has been assumed that the assets are owned by the power station owner and that any additional corporate overheads are insignificant.

4 CONCLUSIONS

4.1 Margin “M”

The use of the term M in the calculation of the capital cost is flawed based on:

1) It presently includes costs that are not a function of the EPC price.
2) It includes costs that are not scalable with plant capacity.

This report identifies the components of term M that could be included as a dollar amount. Presently however, the costs for these items are not material for the 160 MW plant but could become material if escalation methods are used for adjusting the EPC price. The percentages used in the SKM 2010 report appear to be the correct magnitude so these could be converted to dollar values as the starting point. The capital cost calculation equation would become:

“CAPCOST[t] = (PC[t] x (1 + m) x CAP + DC + TC[t] + FFC[t] + LC[t]) x (1+ WACC)^2

Where m includes the EPC related components and DC is a dollar amount for the non EPC related costs.

4.2 Escalation

This report presents an escalation methodology that is aimed at being transparent and using standard published data from the Australian Bureau of Statistics. The exercise shows that the use of indexes and statistics to escalate prices based on historic data is subjective and can be manipulated to produce results. The issues include:

1) There are no indexes specific to gas turbines
2) The gas turbine industry is likely to set prices based on what the market will bear rather than based on changes in commodity prices
3) There are insufficient projects in Australia to influence ABS statistics

Agreement on the indexes used in escalation methods need to be agreed. As can be seen for the transmission and switchyard components, the escalation method used by WorleyParsons and SKM produce different results. The primary objective of the selection of indexes is that they should be transparent and produce suitable estimates. The indexes should also be reviewed regularly to ensure components do not vary too far from reality.

The use of forward looking methods of escalation such as linear regression of historic indexes will provide stable escalation even during periods of market volatility. This methodology should provide consistent results over the the longer term. There are a range of indexes that may be used for the power assets. Agreement on which indexes to use is essential. The accuracy of the forward estimate must be tested regularly. The methodology for setting the baseline EPC cost and future estimates should be agreed and it is recommended that an auditable estimating methodology be established.

SINCLAIR KNIGHT MERZ

SKM

imo

Independent Market Operator

IMO Reserve Capacity Price

PROCESS FOR THE CALCULATION OF THE TERM M

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- 15 March 2011

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- 15 March 2011

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1. Introduction

The IMO has requested SKM to provide a summary of the process it uses to calculate the Term M component of the MRCP calculation for further consideration by the MRCP Working Group.

To this end, this document summarises the process used by SKM in the determination of the Term M and articulates some of the challenges in working with the highly confidential and irregular data set that underpins the M calculation.

2. Background

Section 1.14 of the IMO's market procedure for making a determination of the maximum reserve capacity price version 1.1, introduces and defines the term 'M' as; "*a margin to cover legal, approval, and financing costs and contingencies.*"[1]

SKM understands that the inclusion of term 'M' within the calculation provides a means to account for specific additional indirect costs that would be expected to be incurred by the developers of the Power Station upon which the Maximum Reserve Capacity Price is based.

The indirect costs are then incorporated into the capital cost determination as a margin, i.e. a fixed percentage, added to the capital cost:

Page 11 of the IMO's Market Procedure for Maximum Reserve Capacity Price identifies how the Term M fits into the maximum reserve capacity price calculations, being:

> *"The value of CAPCOST[t] is to be calculated as:*
>
> *CAPCOST[t] = (PC[t] x (1 + **M**) x CAP + TC[t] + FFC[t] + LC[t]) x (1+ WACC)^2*
>
> *Where:*
> *PC[t] is the capital cost of an open cycle gas turbine power station in year t, expressed in Australian dollars in year t per MW;*
> ***M is a margin to cover legal, approval, and financing costs and contingencies**;[Emphasis added]*
> *TC[t] is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS, plus an estimate of the costs of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station, expressed in Australian million dollars in year t;*
> *FFC[t] is the fixed fuel costs and must represent the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times expressed in Australian million dollars in year t;*
> *LC[t] is the cost of land purchased in year [t]; and*
> *WACC is the Weighted Average Cost of Capital."*

---

[1] IMO 2008, "Market Procedure for Determination of the Maximum Reserve Capacity Price, 04 December, P11, Available as a download from: http://www.imowa.com.au/f711,54740/54740_Market_Procedure_for_Maximum_Reserve_Capacity_Price.pdf.

In calculating a suitable figure for 'M,' SKM estimates the Legal, Approval and Financing costs for a generic 160MW open cycle gas turbine plant, being the "*Power Station upon which the maximum reserve capacity price shall be based*" as defined in Section 1.5 of the IMO's proposed methodology.

3. Calculation of the Term M

The term M costs have been estimated from in-house data and knowledge of comparable recent developments. SKM compares and correlates the costing data of several projects to develop a generic OCGT legal; approval and financing cost estimate for a generic 160 MW liquid fuelled open cycle gas turbine plant. Where applicable, varying costs are each normalised and any abnormal cost variations relating to unique or unusual project factors removed.

Table 1 shows the most recent SKM estimate for the term ‘M’ as defined in Appendix 4 of the WEM Rules, with due consideration given to standard industry practices. These costs include:

- legal costs associated with the design and construction of the power station;
- approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;
- Cost of Raising Capital; and
- Owners project management and engineering costs.

Table 1 Estimate of term 'M'

Component of ‘M’	% of Total EPC
Project Management	1.9%
Project Insurance	1.5%
Contingencies	5.0%
Cost of Raising Capital	4.0%
Environmental Approvals	0.7%
Legal Costs	1.2%
Owners Engineers - Part A (Including concept design, specification, tendering, contract negotiations)	0.4%
Owners Engineers - Part B (Including Construction Phase OE Costs, oversee project, witness tests & Commissioning)	3.0%
Initial Spares requirements	0.8%
Site Services (Provision of potable water, construction power, communications, domestic sewerage etc. at site)	0.1%
Total M as a percentage of CAPEX	**18.6%**
Multiplier in CAPEX equation 2	(1 + 0.186)

Further commentary on the calculation of each component of the term M is provided below.

3.1. Project Management and Contingency

The project management cost was derived from knowledge gained through undertaking a number of comparable EPC projects and due diligence reviews over the past 5 years. SKM note that in the most recent review it had limited recent (past year) data to draw from for this metric.

3.2. Project Insurance

The insurance cost was derived from knowledge gained through undertaking a number of comparable EPC projects and due diligence reviews over the past 5 years. In addition, SKM has sought input from recent discussions between SKM and major energy project insurers.

3.3. Cost of Raising Capital

The figure for the 'Cost of Raising Capital' has been estimated based on a fully underwritten project to build a 160MW OCGT power station; this is dependent on the nature of capital markets at the time of the capital raising process. This estimate incorporates the mandate fees of the Lead Arranger and the establishment fees of the Finance Providers. In the most recent report on the term M, SKM has referenced previous historic data, two Western Australian projects, and sought estimates from one company that provides Lead Arranger services in Western Australia.

3.4. Environmental Approvals and Legal Costs

Due to a lack of relevant recent data, in the most recent report SKM escalated the historic environmental approvals costs and legal costs at CPI and divided this by the PC(t) capital cost in the same report. This on the basis that these costs are linked to the price movements in Australia whist the PC(t) base is driven largely by international labour and commodity price trends.

3.5. Owners Engineers Costs, Initial Spares requirements and Site Services

These costs were derived from knowledge gained through undertaking a number of comparable EPC projects and due diligence reviews over the past 5 years.

3.6. Impact of Availability of data over the Past 12 months

Projects that provide a suitable source of data have been notably scarce in the last 12 months, due to both lack of investor confidence and increases in the tightening of financing processes, as a result of the Global Financial Crisis (GFC). For some components of the calculation this has required SKM to escalate previous data using Australian CPI and calculate this escalated cost as a percentage of the PC(t). This process is seen as a fall back, and in some cases supporting, solution to the use of a pool of recent project data.

3.7. Impact of Confidentiality on the Process of Managing Data

Due to the confidential nature of much of the information in the underlying data for this calculation resides behind confidentiality mechanisms (Chinese Walls) within SKM. This necessitates a process of aggregation across multiple projects by the SKM staff that have access to this data within the confidentiality mechanism. This aggregated / averaged information is then provided to the authors of the Term M report. Through this process, a range of disconnected averaging calculations are undertaken to build up the final factors. SKM does not and cannot maintain a central data sheet with the source data for this calculation.

File Note

Date	17 January 2011
Project No	HA01479
Subject	**SKM Cost Escalation Methodology**

The following is a summary description of the SKM methodology underlying the development of the 12.1% June 2010 to June 2011 weighted capital cost escalation rate for the IMO.

1. Background

SKM has been actively researching the increasing 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.

The SKM model develops forecast costs of plant and equipment through the modelling of predicted movements in the underlying drivers of plant and equipments cost, these drivers are:

- CPI
- Labour
- WA Labour
- Steel
- Copper
- Cement

The escalation factors developed for the IMO were based on the most up-to-date information available at the time of compilation.

2. Weighting of Drivers

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

3. Individual escalation component forecasts

Table 1 identifies the individual components of the Generation Plant weighted capital cost escalation rate, as well as the calculated escalation rate between June 2010 and June 2011 for each element.

- **Table 1 Components of the cost escalation rate**

Base escalation indices from June 2010 to June 2011 (Nominal)

	CPI	Labour	WA Labour	Steel	Copper	Cement
Nominal Index	2.8%	4.4%	4.1%	21.5%	30.5%	4.7%

A description of the methodology for developing each of the individual escalation rates now follows:

3.1 CPI

SKM applies a method of forecasting the position of CPI as accepted by the AER in several recent Final Decision for Distribution Utilities, including the NSW, QLD and VIC distribution businesses.

This method adopts the following process:

- Plot two years of forecasts from the most recent RBA Monetary Policy Statement—(the August 2010 Monetary Policy Statement, forecasts were used); and
- Thereafter plot CPI as the RBA inflation target's midpoint of 2.5%.

The CPI figures used during SKM modeling are presented in Table 2.

- **Table 2 Forecast CPI figures**

Year to June	2010	2011	2012	2013	2014	2015	2016	2017
CPI Forecast	3.05%	2.75%	2.75%	3.0%	2.5%	2.5%	2.5%	2.5%

Therefore SKM adopted a Year to June 2011 CPI rate of 2.75%

3.2 Labour

The first of the two labour components of cost escalation captures the change in the cost of labour for Electricity Gas and Water (EGW) or Utilities sector type workers. As this workforce has been in a position to demand greater than average wage rates in recent times, SKM deemed it necessary to separate these costs from General Labour.

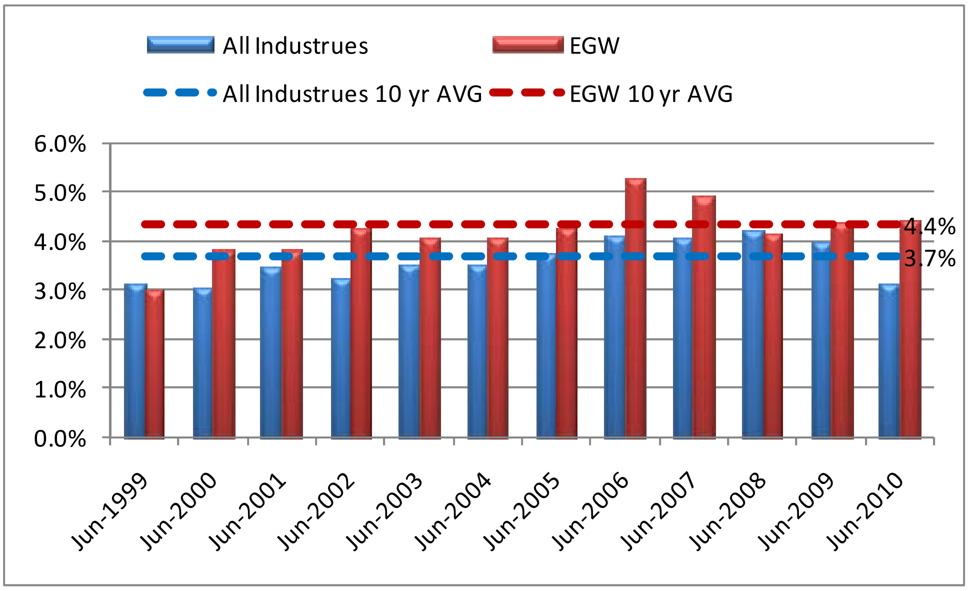
SKM used ABS data to develop this cost escalation component , specifically the ABS 6345.0 Labour Price Index, Australia; Total Hourly Rates of Pay Excluding Bonuses: Sector by Industry, Original (Financial Year Index Numbers for year ended June quarter);Financial Year Index ; Total hourly rates of pay excluding bonuses ; Australia ; Private and Public ; Electricity, gas, water and waste services ; series ID A2705170J

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

- **Table 3 Annual change in EGW LPI index**

Year to:	EGW index	Annual Change
Jun-1998	63.8	
Jun-1999	65.7	1.030
Jun-2000	68.2	1.038
Jun-2001	70.8	1.038
Jun-2002	73.8	1.042
Jun-2003	76.8	1.041
Jun-2004	79.9	1.040
Jun-2005	83.3	1.043
Jun-2006	87.7	1.053
Jun-2007	92.0	1.049
Jun-2008	95.8	1.041
Jun-2009	100.0	1.044
Jun-2010	104.4	1.044
10 year average		1.044

- **Figure 1 EGW compared to all industries**



SKM used the most recent 10 year average annual rate increase of 4.4%

3.3 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 actual costs.

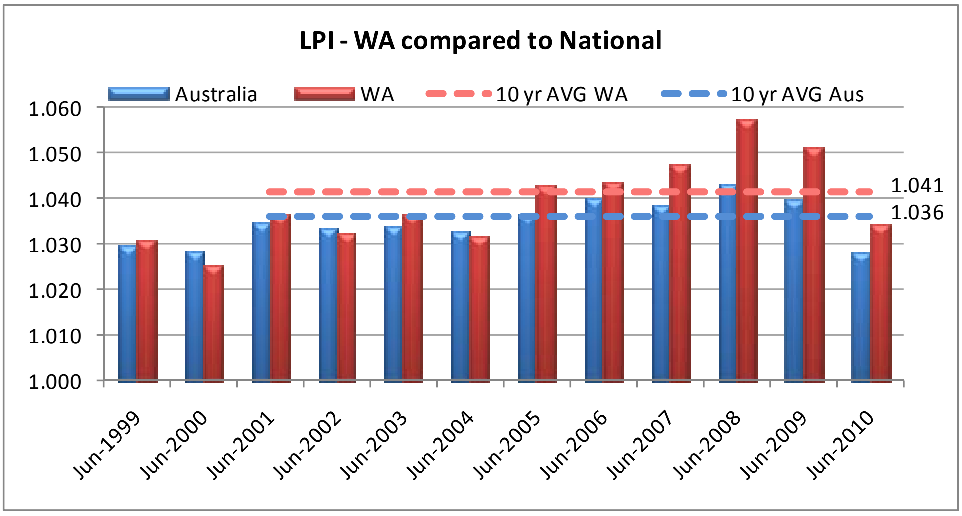
SKM again used ABS data to develop this rate. Specifically ABS 6345.0 Labour Price Index, Australia; All WPI series: Original (Financial Year Index Numbers for year ended June quarter); Financial Year Index ; Total hourly rates of pay excluding bonuses ; Western Australia ; Private and Public ; All industries ; Series ID. A2705992V.

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

- **Table 4 WA wage price index annual changes**

Year to:	WA WPI	Annual Change
Jun-1998	65.2	
Jun-1999	67.2	1.031
Jun-2000	68.9	1.025
Jun-2001	71.4	1.036
Jun-2002	73.7	1.032
Jun-2003	76.4	1.037
Jun-2004	78.8	1.031
Jun-2005	82.2	1.043
Jun-2006	85.8	1.044
Jun-2007	89.9	1.048
Jun-2008	95.1	1.058
Jun-2009	100.0	1.052
Jun-2010	103.4	1.034
10 Year average		1.041

- **Figure 2 Changes in LPI – WA compared to national**



SKM used the most recent 10 year average annual rate increase of 4.1%

3.4 Copper

When developing forecasts for the future annual market price position of the various materials Key Cost drivers, SKM will apply the AER accepted methodology of interpolation between the spot market prices, all available forward contract prices, and credible forecast for future pricing developed by reputable sources specialising in the analysis of the cost driver in question.

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.

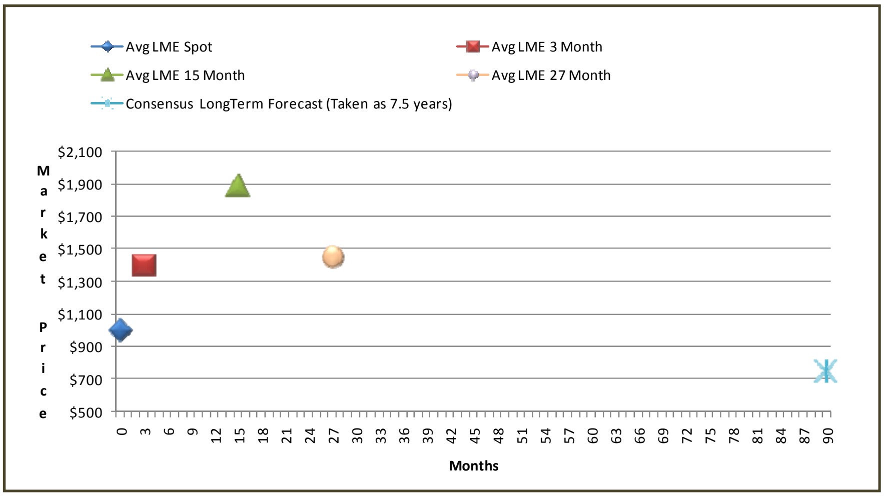
In this instance the process applied by SKM entails a 7 (seven) step approach. This approach is followed in order to produce specific data points between which a simple method of interpolation is able to be applied, in order to fill in any missing data points and arrive at the required market pricing positions.

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 7 (seven) steps involved are:

1) Plot the average of the last 30 days of LME Spot prices
2) Plot the average 3 month LME contract price
3) Plot the average 15 month LME contract price
4) Plot the average 27 month LME contract price
5) Plot the most recent Consensus Long-Term Forecasts position (taken as 7.5 years from survey date[1])
6) Apply linear interpolation between plot points.
7) Identify the Corresponding June points in the interpolated results, take implied Year to June points from these June points, and feed these prices into the model.

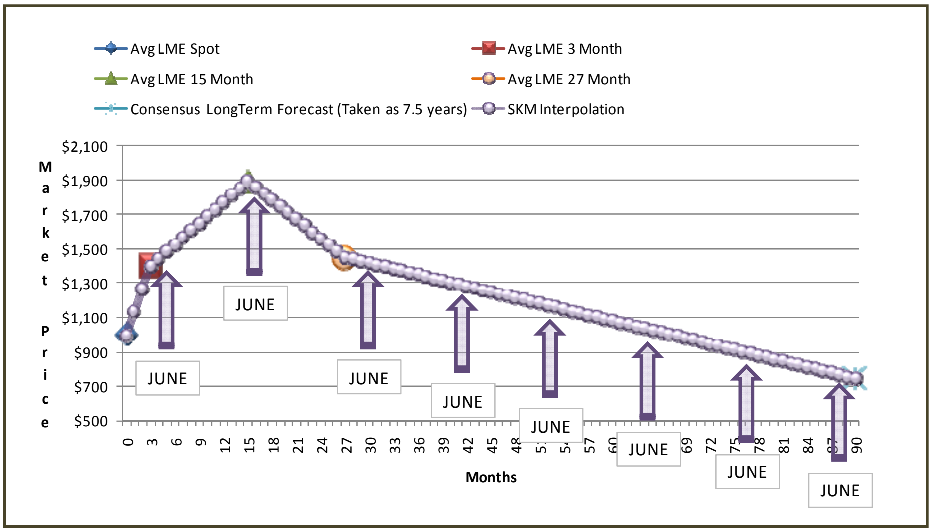
This methodology is represented in Figure 3 and Figure 4.

- **Figure 3 Diagram of SKM methodology (Steps 1-5)**



[1] The Consensus Long-term forecast is listed in the publication as a 5 – 10 year position. In an attempt to apply this in a reasonable manner, SKM consider the position to refer to the mid-point of this range, being 7.5 years, or 90 months hence.

- **Figure 4 Diagram of SKM Methodology (Steps 6 & 7)**



(***Note that all figures are illustrative only and do not refer to the actual position/price of any particular commodity***).

3.4.1 The influence of exchange rates

The SKM methodology for developing cost escalation rates also accounts for the effect on the market price of any cost driver influencing the costs incurred by an *Australian Utility*, by transferring the historic and future prices into Australian Dollar terms from whichever foreign currency they have been quoted in on the markets.

As many of the forecast prices for cost drivers appear on world market quoted in a foreign currency (typically US$) the Australian Dollar's relative position to the currency in which the product is traded will, in itself, influence the cost of finished goods to a Australian Utility.

3.4.2 Expected Price movements for commodities

With average annual commodity prices having fallen so dramatically during 2009 and then displaying significant volatility through early 2010, the markets are now being forecast to continue some price recovery in the short term, before levelling out, reflecting more consistent annual supply and demand conditions.

This move toward increased consistency in supply and demand patterns is widely thought to emerge somewhere around the year to June 2013 period.

Figure 5 shows the predicted movements in the AUD equivalent market prices of the various commodities that influence the price of network plant and equipment.

- **Figure 5 Forecast Annual Commodity Price Movements (REAL- AUD)**

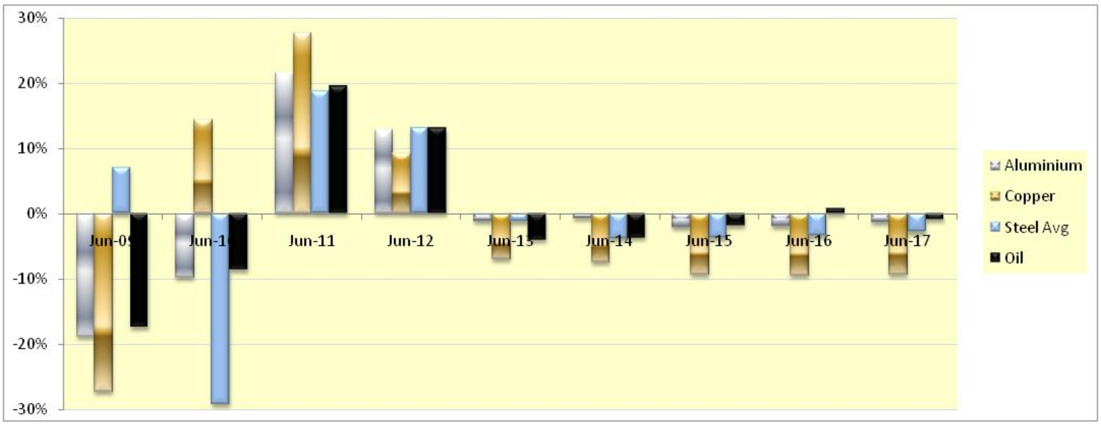
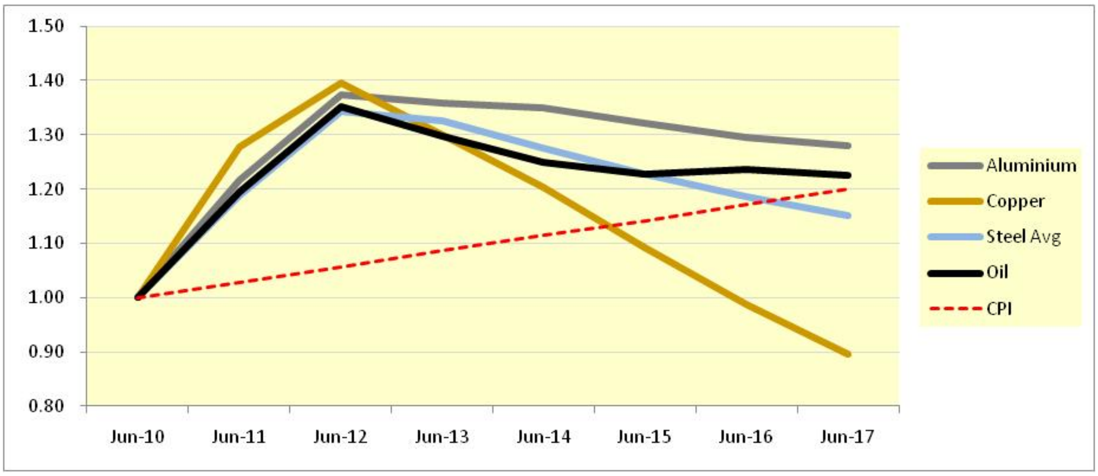


Figure 6 presents the affect of the cumulative real average annual movements of these commodities (against CPI) indexed to their average year to June 2010 position.

- **Figure 6 Indexed annual REAL AUD Commodity Price Movements (indexed to June 2010 base)**



The average year to December input numbers used during SKM's modelling of the Copper market prices are presented in Table 5

- **Table 5 Relative Real AUD based price of Copper**

	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17
Copper	$ 6,693	$ 7,657	$ 9,783	$ 10,694	$ 9,957	$ 9,214	$ 8,357	$ 7,568	$ 6,862
Annual Change	-27%	14%	28%	9%	-7%	-7%	-9%	-9%	-9%

The year to June 2011 *real* escalation rate for copper of 27.8% together with the 2.75% CPI rate provides a nominal escalation rate for the period of 30.5%.

3.5 Steel

An application of the SKM methodology used for developing forward market positions for Copper and other commodities (as described in 3.4 above) is not currently possible for steel, due to the lack of a liquid Steel futures market. SKM note that the LME commenced trading in steel futures in February 2008.[2] However, the LME has communicated that this relatively new steel futures market is undergoing a purposely planned "soft launch", and its liquidity is still being built up.

SKM therefore uses the Consensus Economics forecast as the best currently available outlook for steel prices. Consensus provides quarterly forecast prices in the short term, and a "long term" (5-10 year) price.

Steel prices for all historical periods are taken from an average of the Bloomberg US and EU steel prices.

The most recent Consensus Survey available at the time of compiling this report was their Oct 2010 Survey. This publication provided quarterly forecast market prices for steel from December 2010 to March 2013, as well as a Long-term forecast pricing position.

Consensus Economics provides two separate forecasts for Steel, both being for Hot Rolled Coil (HRC) variety, with the first being relative to the USA domestic market and the other the European domestic market.

The Consensus Economics US HRC price forecasts are presented US$ per *Short Ton*. As historical prices are all quoted in US$ per *Metric Tonne*, it is necessary to convert these prices into their Metric Tonne equivalent. This is a simple operation with the US HRC prices multiplied by a factor of 1.1023, being the standard conversion rate for the number of short tons per Metric Tonne.

An example of this process is shown in Table 6.

Once converted to their Metric Tonne pricing position, SKM uses the average of these two forecasts (US HRC and EU HRC) as its Steel price inputs to the cost escalation modelling process.

The figures used as inputs to SKM's modelling are presented in Table 7.

SKM's methodology of integrating Consensus Steel price forecasts into the development of cost escalation factors adheres to the methodology for cost escalation as accepted by the AER in the NSW Distribution Business's Final Decisions.

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2 http://www.lme.co.uk/5723.asp

- **Table 6 Conversion of Short tons to Metric tonnes. (USD nominal)**

	Sep-10	Dec-10	Mar-11	Jun-11	Sep-11	Dec-11	Mar-12	Jun-12	Sep-12	Dec-12
HRC US in Short tons	676	649	666	684	691	688	689	707	717	704
Equivalent HRC US in Metric tonnes	745	716	734	754	762	759	760	779	791	776

- **Table 7 Relative Real AUD Pricing position of average HRC steel prices**

	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17
Steel Avg	$ 990	$ 701	$ 833	$ 942	$ 930	$ 895	$ 861	$ 831	$ 808
Annual Change	7%	-29%	19%	13%	-1%	-4%	-4%	-3%	-3%

The 18.7% *real* escalation rate together with the 2.75% CPI provides a nominal Steel escalator of 21.5% for the year to June 2011.

3.6 Cement

SKM applied the Construction Forecasting Council's as a proxy for the forecast movement in the cost of Cement.

The Australian Construction Industry Forum (ACIF)[3] is the peak consultative organisation of the building and construction sectors in Australia. The ACIF has established the Construction Forecasting Council (CFC)[4] through which it provides a tool kit of analysis and information.

In commenting on activity in construction related to the electricity industry, the Construction Forecasting Council (CFC) notes that for this sector,

> *"Electricity and pipeline construction activity reached a very high $12 billion in 2008/09 and 2009/10, due to the start of several new projects, including many wind farms. Electricity and pipeline construction is forecast to ease back over the short term as future climate change policy direction needs to be made clearer in this sector. Electricity and pipeline construction is forecast to remain stable at a high level over the medium term"* [5].

3 http://www.acif.com.au/

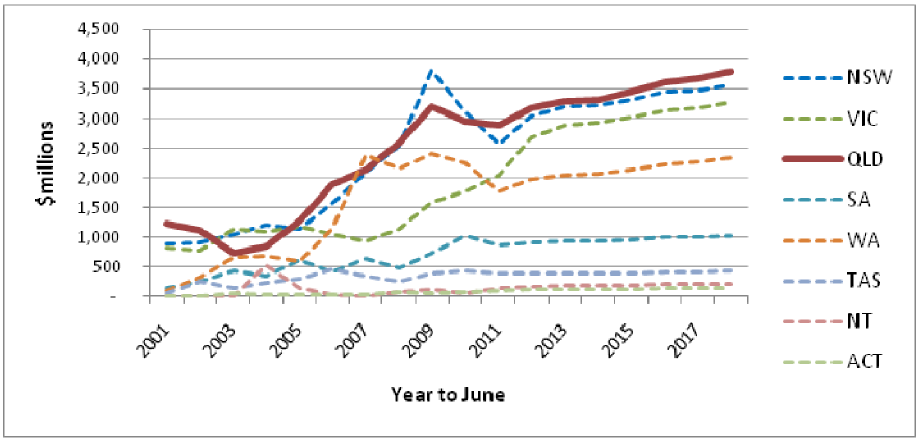
4 http://www.cfc.acif.com.au/cfcinfo.asp

5 http://www.cfc.acif.com.au/summary.asp

This outlook is likely to sustain the market demand for related construction materials, and thus the resultant market prices.

Figure 7 illustrates the CFC's outlook for electricity and pipeline construction demand out to 2017-18. This illustrates how when compared to NSW, VIC and QLD, WA is expected to experience a comparatively lower forward program of construction in this sector, with QLD expected to have the largest program.

- **Figure 7 CFC Electricity and pipeline construction outlook[6]**



The CFC also provides a forecast of related construction costs going forward, through which annual growth rates in the cost of construction are able to be developed. These figures are provided through KPMG Econtech forecasts.

As the CFC considers electricity and pipeline construction to fall within the sector it presents entitled as "Engineering", SKM has adopted these movements presented as Australian National "Engineering" construction cost forecasts as the likely movements in the Construction cost component of relevance to the IMO project within cost escalation modelling.

Engineering construction is forecast to continue rising as new large projects commence. Mining is forecast to be solid as new LNG and iron ore projects commence in Western Australia and Queensland. Road and rail construction are expected to remain at a solid level due to continued government infrastructure spending. The National Broadband Network (NBN) will also boost activity levels.

- **Table 8 CFC Forecast of Engineering construction costs (nominal)**

CFC forecast title	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Long-term - Engineering - Price Index (seasonally adjusted% change)	-5.5%	4.2%	2.2%	-0.4%	0.9%	3.5%	5.3%	5.4%	4.7%

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[6] http://www.cfc.acif.com.au/forecast_results.asp Downloaded 26/11/2010

SKM identified that the CFC *nominal* rate of 4.2% first needed to be made *real* in order to allow for consistent application of CPI assumptions.

The CFC forecasts provide underlying macro economic assumptions, and stated that the YTJ 2011 CPI used in developing the forecasts was 2.2%.

SKM therefore restated the real CFC number using a consistent RBA forecast CPI rate of 2.75%.

The calculation applied was:

- 4.2% (nominal CFC rate) **-** 2.2% (KPMG's CPI assumption) = 2% real escalation in costs.
- 2%real escalation in costs + RBA CPI of 2.75% = **4.75%** nominal escalation in costs.

Trusting this clarifies the methodology employed in developing the 12.1% escalation factor for the generation capital cost from June 2010 to June 2011.

Regards

ALambe
Senior Business Analyst

Agenda Item 5: Analysis of Sensitivity to changes to MRCP Methodology

1. BACKGROUND

It was agreed at the meeting on 24 March 2011 that the IMO would perform a sensitivity analysis to estimate the impact on the MRCP of a lengthening of the Capitalisation Period (currently 15 years), a change in the application of the WACC in the MRCP calculation, a change in the methodology for calculation of the Debt Risk Premium (DRP) and the change in the methodology for the determination of Total Connection Costs (TCC). In addition the IMO has performed analysis to approximate the impact of the inclusion of annual asset insurance costs on the MRCP.

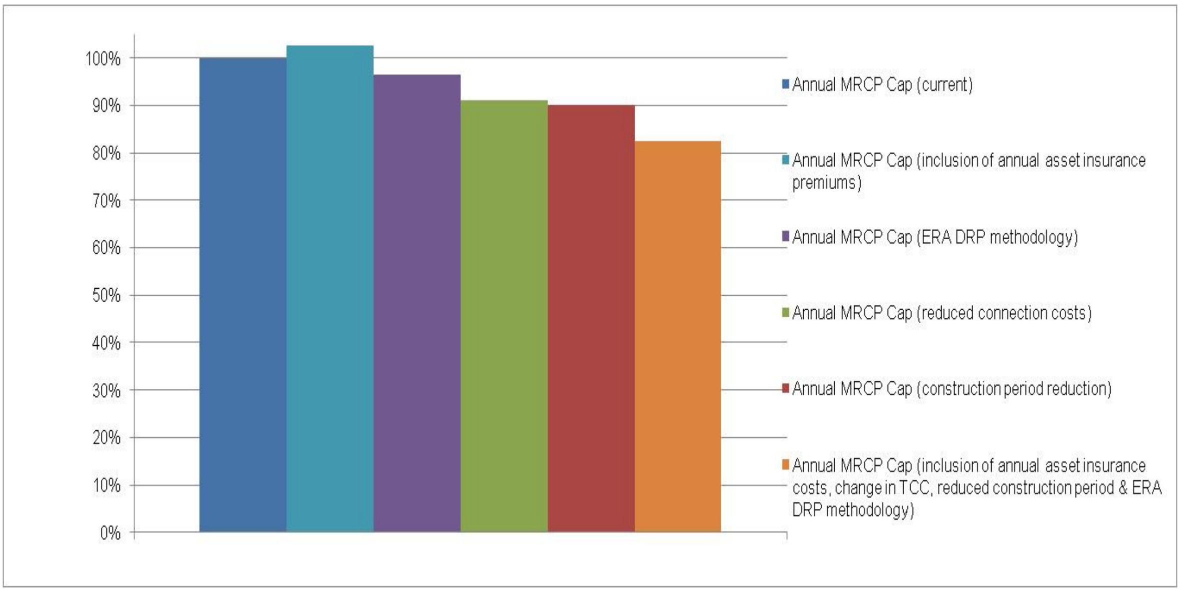
2. SENSITIVITY ANALYSIS

The initial sensitivity analysis has been performed by varying the values of various parameters within the MRCP calculation for the 2013/14 Capacity Year. The following variations have been considered:

- A comparison has been performed on the application of the WACC within the MRCP calculation to allow for 6 months of return (as proposed by Pricewaterhouse Coopers and endorsed by the MRCPWG) versus 2 years, as is currently applied.
- A comparison has been performed based on the DRP values presented by the ERA at the 24 March 2011 meeting, calculated as at 20 December 2010. The DRP for the Bond-yield approach as favoured by the ERA was 2.685% (giving a real pre-tax WACC of 7.65%) versus 4.019% (WACC of 8.17%) under the current approach which utilises data from Bloomberg.
- A comparison has been performed between the TCC methodology as proposed by SKM and endorsed by the MRCPWG, producing a TCC of $127,000 per MW for the 2011 MRCP, and the current methodology which yielded a TCC of $305,000 per MW.
- A comparison has been performed to estimate the impact of the inclusion of annual asset insurance premiums within the fixed O & M cost. The IMO has made contact with a number of insurance brokers to ascertain details on annual asset insurance costs for the model plant. We await detailed feedback from brokers, however for the purposes of this comparison an estimate of $6,250 per MW has been used, which is based Perth Energy's submission during the 2011 MRCP cycle[1]. In its submission, Perth Energy indicated that insurance for a 160MW OCGT would be approximately $1m per year, so this value has been divided by the 160MW capacity.

The graphs shown below illustrate the impact of a variation in the components listed above on the MRCP. Note that the base case (current method) does not align with the 2011 MRCP due to the use of an updated Debt Risk Premium value of 4.019%, resulting in a lower WACC.

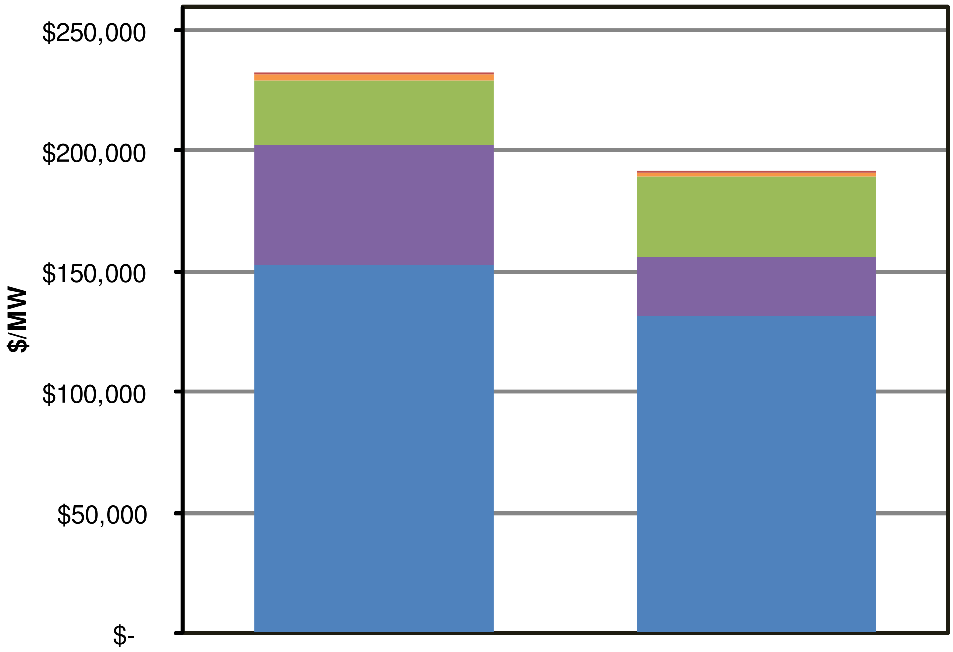
[1] http://www.imowa.com.au/f175,877637/Perth_Energy_submission_Draft_IMO_MRCP_Report.pdf



MRCP with current methodology *	MRCP with insurance costs	MRCP with ERA's proposed DRP methodology	MRCP with proposed TCC methodology	MRCP with WACC applied based on 6 months return	MRCP with all changes incorporated
232,691.79	238,941.79	224,318.77	211,814.59	209,794.85	191,944.71
100%	103%	96%	91%	90%	82%

*Note that the current MRCP illustrated above has been calculated using an estimation of Bloomberg's 7-year BBB fair yield as at 20 Dec 2010 for comparison purposes.

The graph shown below illustrates the relative contribution of the various component costs to the total MRCP, both under the current methodology and under a methodology where the TCC and DRP calculation methodologies are amended, the WACC is applied based on 6 months return and the annual insurance costs are included within the Fixed O&M component.

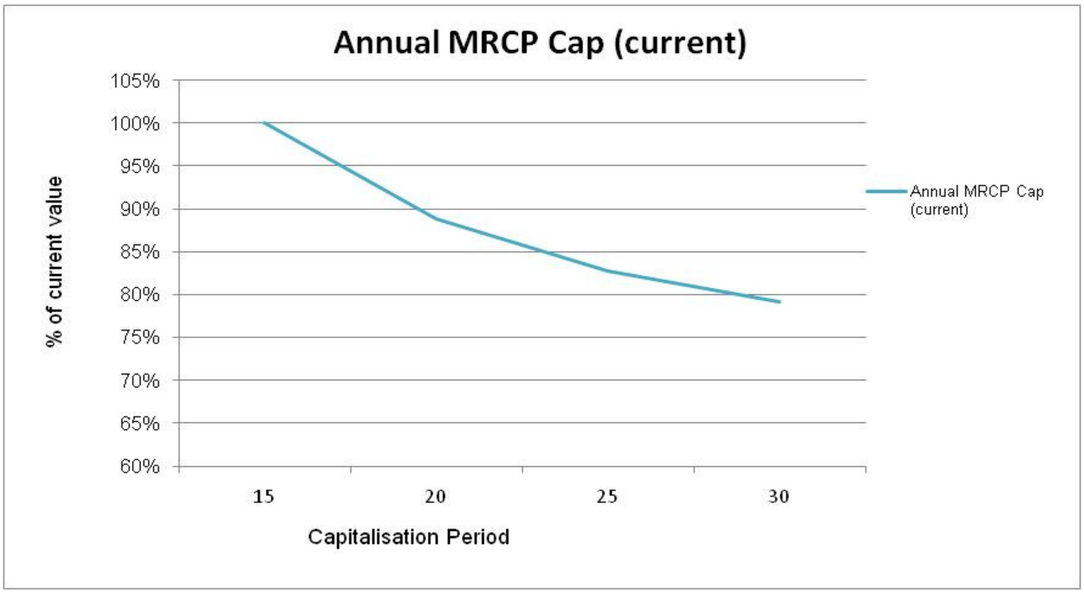


Capacity Year	13/14 current		13/14 revised	
Power Station Cost	$	152,828	$	131,270
Transmission Costs	$	49,708	$	24,763
Fixed O& M	$	26,648	$	32,898
Fuel Costs	$	2,720	$	2,336
Land Costs	$	787	$	676
MRCP (nearest $100)	$	232,700	$	191,900

3. IMPACT OF CHANGE IN CAPITALISATION PERIOD

In addition, the MRCPWG requested that the IMO perform an analysis of the impact of a change in the capitalisation period (currently 15 years) on the MRCP.

The graph and table below shows the impact of a lengthening of the capitalisation period up to 30 years.



Term of Capitalisation (Years)	Reduction in MRCP (relative to 15 year capitalisation)
15	-
20	11%
25	17%
30	21%

The IMO notes that documents from the Electricity Reform Implementation Unit (ERIU) indicate that the selection of a 15 year capitalisation period was intended to provide "headroom", given that the MRCP is a price cap. The ERIU noted that the operating life of the plant is "likely to be well over 20 years".

An increase in the capitalisation period from 15 years is supported by an Australian Taxation Office (ATO) Ruling (TR 2010/02 - 26110 to 26400[2] page 102) on the effective life of assets in the Electricity Supply sector. This Ruling lists the life of Gas Turbine Generators as 30 years.

Given this, the IMO considers that an increase in the capitalisation period to 20 years would still provide head room while moving closer to the likely operating life of such a facility. However, the IMO notes that a further 11% reduction in the next MRCP, on top of an 18% reduction due to the methodology changes analysed in Section 2 of this paper, would deliver a considerable price shock.

Consequently, the IMO recommends a staged implementation of this change, with the capitalisation period:

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[2] http://law.ato.gov.au/pdf/pbr/tr2010-002.pdf

- Remaining at 15 years for the 2012 MRCP;
- Increasing the capitalisation period by 1.25 years for each subsequent MRCP determination through to the 2016 MRCP (11% reduction as per above); and

This glide path will avoid an additional price shock for the 2012 MRCP and improve investment signals. The capitalisation period can then be further reviewed in the next 5-yearly review of the MRCP methodology.

4. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Note** the impact of the changes in the Capitalisation Period, DRP calculation methodology and TCC calculation methodology on the MRCP; and
- **Note** the IMO's recommendation to move, with a glide path, to a 20 year capitalisation period.

Agenda Item 6: Draft Market Procedure

1. BACKGROUND

The MRCPWG has arrived at a number of agreed outcomes during its work to date. These outcomes include the following:

- Power Station type: the appropriate power station type is an Open Cycle Gas Turbine with low NOx burners and inlet cooling, operating on distillate with 2% capacity factor;
- Power Station type: the appropriate quantity of capacity is 160 MW, provided as a single facility with a nominal nameplate capacity of 160 MW;
- Summer De-rating Factor (SDF): the SDF should be specified by the Consultant who develops the Power Station costs, according to available turbine and inlet cooling technology, and taking into account humidity conditions, replacing the value of 1.18 currently indicated in the Market Procedure;
- Power Station cost: the Consultant who develops the Power Station costs should specify uplift factors for construction costs in the current list of geographical locations;
- Transmission Connection Cost: Western Power is the appropriate party to determine shallow connection costs;
- Transmission Connection Cost: the Total Connection Cost methodology proposed by SKM should be implemented;
- Fixed Fuel Cost: the Fixed Fuel Cost should include an allowance to maintain sufficient fuel levels for 14 hours of operation at all times, not 12 hours as currently indicated in the Market Procedure;
- Fixed Operation and Maintenance (O&M): the cost of insurance to replace the facility should be included as a Fixed O&M cost;
- Land Cost: Landgate is the appropriate party to determine land costs;
- Land Cost: the current list of land locations is appropriate, although there should be greater flexibility to add to the list where appropriate;
- Land Cost: a Market Participant may not be required to purchase any required buffer zone if the facility was located in an industrial precinct, so the land size should be standardised at 3 hectares with the stipulation that the buffer zone must exist where required;
- Land Cost: for any location where 3 hectare lots can not be purchased, the lot size should be amended to represent the next largest available lot size in that location;
- Weighted Average Cost of Capital (WACC): the IMO should continue to determine the WACC with the ERA reviewing this in its approval of the MRCP in accordance with clause 2.26.1 of the Market Rules;
- WACC: the majority of recommendations by Pricewaterhouse Coopers will be accepted, excluding the gearing ratio and debt risk premium;

- WACC: the IMO will continue to determine the WACC on a real pre-tax basis
- WACC: debt issuance costs will be included in the WACC calculation and no longer included in the margin M;
- WACC: the gearing ratio will be kept at 40%;
- WACC: the IMO should be allowed the flexibility to select the Debt Risk Premium methodology to align with accepted regulatory practice; and
- Cost optimisation: Land, Transmission and Construction Costs should be optimised to determine the cheapest location.

The IMO presented a draft Market Procedure to the 24 March 2011 meeting and requested that the MRCPWG members provide out-of-session feedback on this document. No out-of-session submissions were received.

2. UPDATED DRAFT MARKET PROCEDURE

The IMO has updated the *Market Procedure: Maximum Reserve Capacity Price* to reflect the IMO's new format arising from its Market Procedure project and to incorporate the agreed changes listed above. The IMO notes that the MRCPWG has yet to finalise some remaining elements of the MRCP, and has highlighted these sections of the Market Procedure in yellow.

The following changes have been made since the 24 March 2011 meeting, reflecting agreed outcomes from that meeting:

- Transmission Connection Cost: the Total Connection Cost methodology proposed by SKM should be implemented;
- Fixed Operation and Maintenance (O&M): the cost of insurance to replace the facility should be included as a Fixed O&M cost;
- Land Cost: for any location where 3 hectare lots can not be purchased, the lot size should be amended to represent the next largest available lot size in that location; and
- WACC: the IMO should be allowed the flexibility to select the Debt Risk Premium methodology to align with accepted regulatory practice.

The updated draft Market Procedure is provided to the MRCPWG for its evaluation and consideration.

3. REQUIREMENTS OF MRCPWG TERMS OF REFERENCE

The MRCPWG Terms of Reference require the MRCPWG to "Develop an integrated suite of solutions, including drafted Procedure Change Proposals to be presented to the MAC by way of presentation/s and supporting discussion papers." The Terms of Reference also require a full impact assessment be conducted.

The IMO proposes to develop a Procedure Change Proposal and undertake the impact assessment following the meeting. Another meeting of the MRCPWG will be called to review these documents.

4. RECOMMENDATIONS

The IMO recommends that the MRCPWG:

- **Review** the amendments made to the *Market Procedure: Maximum Reserve Capacity Price*;
- **Note** that the IMO will further amend the Market Procedure to reflect agreed outcomes at the 5 May 2011 meeting; and
- **Note** that the IMO will develop a Procedure Change Proposal and undertake a full impact assessment.

MARKET PROCEDURE: Maximum Reserve Capacity Price

VERSION 54

ELECTRICITY INDUSTRY ACT 2004

ELECTRICITY INDUSTRY
(WHOLESALE ELECTRICITY MARKET)
REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

COMMENCEMENT:

This Market Procedure took effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rules.

VERSION HISTORY

VERSION	EFFECTIVE DATE	NOTES
1	13 October 2008	Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_06
2	4 December 2008	Amended Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_14
3	1 April 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2009_12
4	11 October 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2010_04
5	XXXX	Amendments to the Procedure resulting from XXXX

CONTENTS

Independent Market Operator

1 PROCEDURE FOR DETERMINING THE MAXIMUM RESERVE CAPACITY PRICE

This procedure for determining the Maximum Reserve Capacity Price sets out the principles to be applied and steps to be taken by the Independent Market Operator (IMO) in order to develop and propose the Maximum Reserve Capacity Price as required under the Market Rules. Under the Market Rules, the Maximum Reserve Capacity Price is used as the price cap for the Reserve Capacity Auction in the event that one is held. It is also used as the basis of determining the price of uncontracted Capacity Credits in the case where the Reserve Capacity Auction is cancelled.

1.1 Interpretation

1.1.1 In this procedure, unless the contrary intention is expressed:

(a) terms used in this procedure have the same meaning as those given in the Wholesale Electricity *Market Amending Rules* (made pursuant to Electricity Industry (Wholesale Electricity Market) Regulations 2004);

(b) to the extent that this procedure is contrary or inconsistent with the Market Rules, the Market Rules shall prevail to the extent of the inconsistency;

(c) a reference to the Market Rules or Market Procedures includes any associated forms required or contemplated by the Market Rules or Market Procedures; and

(d) words expressed in the singular include the plural or vice versa.

1.2 Purpose

The purpose of this procedure is to describe the steps that the IMO must undertake in determining the Maximum Reserve Capacity Price in each Reserve Capacity Cycle.

This procedure is made in accordance with clause 4.16.3 of the Market Rules.

1.3 Application

1.3.1 This procedure applies to:

(a) The IMO in determining the Maximum Reserve Capacity Price; and

(b) Western Power in developing estimates of the costs associated with connecting a notional Power Station to the 330 kV transmission system.

1.4 Overview of the Maximum Reserve Capacity Price

The Maximum Reserve Capacity Price sets the maximum offer price that can be submitted 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 IMO is required to conduct a review of the appropriateness of a number of the components that are used to determine the Maximum Reserve Capacity Price.

1.5 Definition of Power Station

1.5.1 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;~~.~~

(c) operate on distillate as its fuel source;~~.~~

(d) have a capacity factor of 2%;~~.~~

(e) include low Nitrous Oxide (NOx) burners or associated technologies as would be required to demonstrate good practice in power station development; and~~.~~

(f) include an inlet air cooling system.

1.6 Scope of the Factors to Maximum Reserve Capacity Price

1.6.1 The Maximum Reserve Capacity Price is to include all reasonable costs expected to be incurred in the development of the Power Station, which will include estimation and determination of:

(a) Power Station balance of plant costs, which are those other ancillary and infrastructure costs that would normally be experienced when developing a project of this nature;

(b) land costs;

(c) costs associated with the development of liquid fuel storage and handling facilities;

(d) costs associated with the connection of the Power Station to the bulk transmission system;

(e) allowances for legal costs, insurance costs, financing costs and environmental approval costs;

(f) reasonable allowance for a contingency margin; and

(g) estimates of fixed operating and maintenance costs for the Power Station, fuel handling facilities and the transmission connection components.

1.7 Development of Costs for the Power Station

1.7.1 The IMO shall engage a consultant to provide advice, including an estimate of the costs associated with designing, purchasing and constructing the Power Station. The Power Station costs shall be determined with specific reference to the use of actual project-related data and shall take into account the specific development 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) Worldwide demand for gas turbine engines for power stations.

(c) The engineering, design and construction, environment and cost factors in Western Australia.

(d) The level of economic activity at the state, national and international level.

1.7.2 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. This must include, but will not be limited to the following items:

(a) Civil Works.

(b) Mechanical Works.

(c) Electrical Works.

(d) Buildings and Structures.

(e) Engineering and Plant Setup.

(f) Miscellaneous and other costs.

(g) Communications and Control equipment.

(h) Commissioning Costs.

1.7.3 Power Station Costs must be estimated for all locations listed in step 1.11.1 through the use of locational multipliers, as at June in Year 1 of the Reserve Capacity Cycle. Where Power Station Costs have been determined at a different date, those costs must be escalated using a power station capital cost escalation factor.

The methodology for determining the power station capital cost escalation factor shall be determined by the IMO.

1.7.4 The Consultant employed under 1.7.1 shall determine a Summer De-rating Factor for the Power Station which shall take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors.

1.8 Transmission Connection Works

1.8.1 Western Power will forecast the Total Connection Costs based on historic connection costs and relevant access offers for generators that are capable of being liquid fuelled. This forecasting methodology will incorporate the following:

(a) Each Connection Cost or Access Offer should include all transmission costs from the terminals of the generator step up transformer into the network (including costs of procuring land easements etc.). If Western Power's connection cost data does not include all of the costs within this scope these costs should be estimated using Western Power's estimating methodology. All costs shall be with reference to the year of commissioning of the generator.

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(b) For years for which no suitable historic data is available a connection cost will be calculated on the basis defined in clause 1.8.2.

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(b) The sum of connection costs for each year should be divided by the sum of the generators' certified capacity in that year to provide an "average per unit capacity" connection cost for each year.

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(c) The average per unit capacity costs should be escalated into the dollars of the year of calculation. The basis of escalation will be the average change over 5 years in the estimates calculated consistent with clause 1.8.2.

(d) The escalated per unit capacity costs for the relevant Capacity Year and the 4 years preceding should be multiplied by the weighting factor in the table below:

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Year	Weighting
MRCP Calculation Year	7
MRCP Calculation Year - 1	5
MRCP Calculation Year - 2	3
MRCP Calculation Year - 3	1
MRCP Calculation Year – 4	1

The sum of the 5 years of scaled, escalated, average per unit capacity costs for the 5 years under consideration should be divided by 17 to provide a weighted average per unit connection cost.

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(e) The weighted average per unit cost shall be scaled up by a 15% forecasting error margin to provide the forecast connection cost for the relevant Capacity Year as at June in Year 1 of the Reserve Capacity Cycle.

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(f) Western Power must appoint a suitable auditor to review the application of the process in clause 1.8.1 on an independent and confidential basis. Western Power must provide the advice of the auditor to the IMO, who must publish the advice.

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~~Western Power shall provide Transmission Connection Cost Estimates on the basis defined in Step 0.~~

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1.8.2 ~~The Transmission Connection Cost Estimate shall be developed on the following basis~~For the purposes outlined in step 1.8.1, Western Power will also estimate the cost of a direct transmission connection on the following basis:

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(a) The capital cost (procurement, installation and commissioning, excluding land cost) of a generic, industry standard 330kV substation that facilitates the connection of the Power Station will be estimated.

(b) The estimate will include all the components and costs associated with a standard substation.

(c) The estimated cost will be based on a generic three breaker mesh substation configured in a breaker and a half arrangement.

(d) The substation will be located adjacent to an existing transmission line and include an allowance for 2km of 330kV overhead single circuit line to the power station that will have one road crossing.

(e) 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.

(f) The connection of the substation into the existing transmission line will be turn-in, turn-out and will be based on the most economical (i.e. least cost) solution. It is assumed that the existing transmission line will not require modification to allow the connection with the exception of one new tower located at the substation to allow a point of connection.

(g) Costs associated with any staging works will not be considered.

(h) Shallow connection easement costs will be considered.

~~(i) An estimate of deep connection costs shall be included.~~

Independent Market Operator

1.9 ~~Liquid Fuel Storage and Handling Facilities~~Fixed Fuel Cost

1.9.1 The IMO must determine appropriate and reasonable costs for the Liquid Fuel storage and handling facilities. Costs associated with the following items should be developed:

(a) A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund.

(b) Facilities to receive fuel from road tankers.

(c) All associated pipework, pumping and control equipment.

1.9.2 The estimate should 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) The capacity of the storage tank should be sufficient to allow for 24 hours of continuous operation at maximum capacity for a 160 MW open cycle gas turbine power station.

(c) Any costing components that may be time-varying in nature must be disclosed as part of the modelling. Such components might be the cost of the liquid fuel, which will vary over time and as a function of exchange rates etc.

1.9.3 The costing should only reflect fixed costs associated with the Fixed Fuel Cost (FFC) component and should include an allowance ~~for keeping~~ to initially supply fuel sufficient to allow for the Power Station to operate for 14 hours at maximum capacity~~the tank half full at all times~~.

1.9.4 The IMO may engage a consultant to assist the IMO in reviewing and estimating the costs associated with liquid fuel storage and handling facilities.

1.9.5 Fixed Fuel Costs (FFC) must be determined as at June in Year 1 of the Reserve Capacity Cycle. Where Fixed Fuel Costs have been determined at a different date, those costs must be escalated using annual CPI as published by the Australian Bureua of Statistics (ABS), on a June to June basis, as a cost escalation factor.

1.10 Fixed Operating and Maintenance Costs

1.10.1 The IMO must determine Fixed Operating and Maintenance (O&M) costs for the Power Station and the associated transmission connection works.

1.10.2 The Fixed O&M costs may be separated into those costs associated with the Power Station (including annual asset insurance), those costs associated with the transmission connection infrastructure and any other major components that are considered likely to be of sufficient magnitude so as to require separate determination.

1.10.3 Fixed O&M costs shall also include fixed network access and/or ongoing charges, which are to be provided by Western Power.~~.~~

1.10.4 To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component shall be presented in 5 year periods covering 1 to 5 years; 6 to 10 years; 11 to 15 years; 16 to 20 years; 21 to 25 years; 26 to 30 years; 31 to 35 years; 36 to 40 years; 41 to 50 years; 51 to 55 years; and 56 to 60 years as required respectively.

1.10.5 The Fixed O&M costs associated with each major component shall be converted into an annualised Fixed O&M cost as required in the determination methodology section (1.14).

1.10.6 The IMO may engage a consultant to assist the IMO in reviewing and estimating the Fixed O&M costs.

1.10.7 Fixed O&M costs must be determined as at June in Year 1 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using:

(a) 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

(c) cpi as published by the Australian Bureau of Statistics for fixed network access and/or ongoing charges

~~1.10.6~~1.10.8 The methodology for determining the Fixed O&M Costs escalation factors shall be determined by the IMO.

1.11 Land Costs

1.11.1 The IMO shall retain Landgate under a consultancy agreement each year to provide valuations on parcels of industrial land. The regions in which the analysis would be conducted ~~are~~will include:

(a) Collie Region

(b) Kemerton Industrial Park Region

(c) Pinjar Region

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(d) Kwinana Region

(e) North Country Region

(f) Kalgoorlie Region

These areas represent the regions within the South West interconnected system (SWIS) where generation projects are most likely to be proposed and should provide a broad cross-section of options. Where appropriate, the IMO may include additional locations.

1.11.2 The IMO will contract with Landgate to conduct the valuations on the same land parcel size, so as to provide a consistent method of valuing the cost of purchase of the land. The IMO will provide an indication as to the size of land required, which should be limited to the following options:

(a) One 3ha parcel of land in an industrial area of a standard size with consideration given to any requirements for a buffer zone in that specific location. ~~which does not require a significant buffer zone due to its classification. For example. 3 ha.~~ Where the minimum land size available in any specific location is greater than 3ha, for the purpose of calculating the land cost for that specific location, the minimum available land size at that location shall be used.

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(b) The summation of multiple smaller parcels of land as appropriate to meet the requirements above.

c) ~~One larger parcel of land which includes the requirement of a buffer zone. For example. 30 ha.~~

1.12 Legal, Financing, Insurance, Approvals and Other Costs (margin M)

1.12.1 The IMO shall determine ~~an estimate for~~ 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 such as debt and equity raising costs not directly covered in the debt issuance costs within the Weighted Average Cost of Capital~~application of the cost of finance the Maximum Reserve Capacity Price~~.

(c) insurance costs required to insure the replacement of capital equipment and infrastructure;~~. This component shall be computed as part of the determination of the Weighted Average Cost of Capital (WACC).~~

(d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;

(e) other fixed costs associated with operating and maintaining the Power Station; and

(f) contingency costs, where this shall be equal to a factor of 0.15.

1.12.2 The IMO may engage a consultant or consultants to directly estimate costs associated with the provision of Legal Costs, Financing, Insurance and Environmental approval costs.

1.13 Weighted Average Cost of Capital (WACC)

1.13.1 The IMO must determine the cost of capital to be applied to various costing components of the Maximum Reserve Capacity Price. This cost of capital shall be an appropriate WACC for the generic Power Station project considered, where that project is assumed to receive Capacity Credits through the Reserve Capacity Auction and be eligible to receive a Long-Term Special Price Arrangement through the Reserve Capacity Mechanism.

1.13.2 The WACC will be applied directly:

(a) in the annualisation process used to convert the Power Station project capital cost into an annualised capital cost; and

(b) to account for the cost of capital in the time period between when the Reserve Capacity Auction is held (i.e. when capital is raised), and when the payment stream is expected to be realised. ~~To maintain computational simplicity, the nominal time for this period is two years.~~To maintain computational simplicity it is assumed that the total investment cost of the generic power station will be incurred in even incremental amounts over the 12 month period immediately preceding the first Reserve Capacity Year. As a result the effective compensation period for the total investment cost for the generic power station will be six months as detailed in the CAPCOST[t] formula in step 1.14.1.

1.13.3 The methodology adopted by the IMO to determine the WACC ~~may~~ will involve a number of components that require review. These components ~~will normally be~~are classed as those which require review annually (called Minor components) and those structural components of the WACC which require review less frequently (called Major components) as detailed in step 1.13.8.~~.~~

~~1.13.4 The IMO must determine the WACC for the purposes of calculating the Maximum Reserve Capacity Price.~~

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~~1.13.5~~1.13.4 In determining the WACC, the IMO:

(a) must annually review the Minor components; and.

(b) may review the Major components 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 accordance with clause 4.16.9 of the Market Rules.

~~1.13.6~~1.13.5 The IMO may engage a consultant to assist the IMO in reviewing the Major and Minor components of the WACC.

~~1.13.7~~1.13.6 The IMO shall compute the WACC on the following basis:

(a) The WACC shall use the Capital Asset Pricing Model (CAPM) as the basis for calculating the return to equity.

(b) The WACC shall be computed on a Pre-Tax basis.

(c) The WACC shall use the standard Officer WACC method as the basis of calculation.

~~1.13.8~~1.13.7 The pre-tax real Officer WACC shall be calculated using the following formulae

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

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

Where:

(a) R_e is the nominal return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

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

Where:

R_f is the nominal risk free rate for the Capacity Year;

β_e is the equity beta; and

MRP is the market risk premium.

(b) R_d is the nominal return on debt and is calculated as:

$$R_d = R_f + DM$$

Where:

R_f is the nominal risk free rate for the Capacity Year;

~~*DRP*~~ *DM* is the debt ~~risk premium for the Capacity Year~~margin, which is calculated as the sum of the debt risk premium (DRP) and debt issuance cost (d).~~;~~

(c) *t* is the benchmark rate of corporate income taxation, established at either an estimated effective rate or a value of the statutory taxation rate;

(d) γ is the value of franking credits;

(e) *E/V* is the market value of equity as a proportion of the market value of total assets;

(f) *D/V* is the market value of debt as a proportion of the market value of total assets; and

(g) The nominal risk free rate, R_f, for a Capacity Year is the rate determined for that Capacity Year by the IMO on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years:

– using the indicative mid rates published by the Reserve Bank of Australia;

and

– averaged over a 20-trading day period.

(h) The debt risk premium, *DRP*, for a Capacity Year is the premium determined for that Capacity Year by the IMO as the margin between the observed annualised yields of Australian ~~benchmark~~ corporate bonds, ~~rate for corporate bonds~~ which have a BBB~~+~~ (or equivalent) credit rating from Standard & ~~and~~ Poor's, in the benchmark sample and ~~a maturity of 10 years and the~~ an applicable nominal risk free rate with a term to maturity relevant to the bonds in the benchmark sample. The methodology used to estimate the DRP should be accepted by regulatory practice. The IMO must outline and justify its choice.~~:~~

~~– using the predicted yields for corporate bonds published by Bloomberg; and the nominal risk free rate calculated as directed above; and~~

~~– the nominal risk free rate and Bloomberg yields averaged over the same 20-trading day period.~~

(i) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in s~~S~~tep~~s~~ 1.1.1(g) ~~and 1.1.1(h)~~, the IMO

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must determine the nominal risk free rate ~~and the *DRP*~~ by interpolating on a straight line basis from the two bonds closest to the 10 year term and which also straddle the 10 year expiry date.

(j) If the ~~methodology~~ methods used in ~~S~~steps 1.13.8(h) and 1.13.8(i) cannot be applied due to suitable bond terms being unavailable, the IMO may determine the nominal risk free rate and the DRP by means of an appropriate approximation.

~~(j)~~(k) *i* is the forecast average rate of inflation for the 10 year period from the date of determination of the WACC. In establishing a forecast of inflation, the IMO is to have 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.

~~(k) *i* is the forecast rate of inflation. In establishing a forecast of inflation, the IMO is to have regard to the forecasts of the Reserve Bank of Australia, the Western Australian Department of Treasury and Finance, and financial market participants.~~

~~1.13.9~~1.13.8 The CAPM shall use the following parameters as variables each year.

CAPM Parameter	Notation/Determination	Component	Value
Nominal risk free rate of return (%)	R_f	Minor	TBD
Expected inflation (%)	~~π_e~~ i	Minor	TBD
Real risk free rate of return (%)	R_{fr}	Minor	TBD
Market risk premium (%)	*MRP*	Major	6.00
Asset beta	β_a	Major	0.5
Equity beta	B_e	Major	0.83
Debt risk premium~~margin~~ (%)	~~*DM*~~*DRP*	Minor	TBD
Debt issuance costs (%)	d	~~Minor~~Major	~~TBD~~0.125
Corporate tax rate (%)	*t*	Major	30
Franking credit value	γ	Major	0.5
Debt to total assets ratio (%)	*D/V*	Major	40
Equity to total assets ratio (%)	*E/V*	Major	60

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1.14 Determination of the Maximum Reserve Capacity Price

1.14.1 The IMO shall use the following formulae to determine the Maximum Reserve Capacity Price:

A value for PRICECAP[t] shall be determined for each of the locations as listed under step 1.11.1. The lowest determined value for PRICECAP[t] shall be used as the Maximum Reserve Capacity Price.

~~The Maximum Reserve Capacity Price to apply for a Reserve Capacity Auction held in calendar year t is PRICECAP[t] where this is to be calculated as:~~

PRICECAP[t] = (ANNUALISED_FIXED_O&M[t] + ANNUALISED_CAPCOST[t] / (CAP / SDF))

Where:

PRICECAP[t] is the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction held in calendar year t;

ANNUALISED_CAPCOST[t] is the CAPCOST[t], expressed in Australian dollars in year t, annualised over a 15 year period, using a Weighted Average Cost of Capital (WACC) as determined as part of the Maximum Reserve Capacity Price Market Procedure and updated as required;

CAP is the capacity of an open cycle gas turbine, expressed in MW, and equals 160MW;

SDF is the summer derating factor of a new open cycle gas turbine, and ~~equals 1.18~~shall be determined, in conjunction with Power Station costs in step 1.7.3;~~;~~

CAPCOST[t] is the total capital cost, expressed in million Australian dollars in year t, estimated for an open cycle gas turbine power station of capacity CAP; and

ANNUALISED_FIXED_O&M[t] is the annualised fixed operating and maintenance costs for a typical open cycle gas turbine power station and any associated electricity transmission facilities, expressed in Australian dollars in year t, per MW per year.

The value of CAPCOST[t] for each location is to be calculated as:

CAPCOST[t] = (PC[t] x (1 + M) x CAP + TC[t] + FFC[t] + LC[t]) x (1+ WACC)^~~2~~$^{1/2}$

Where:

PC[t] is the capital cost of an open cycle gas turbine power station in year t, expressed in Australian dollars in year t per MW as determined in step 1.7 for that location;

M is a margin to cover legal, approval, financing and ~~and financing~~ other ~~costs and~~ contingencyies costs as detailed in step 1.12;

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TC[t] is the Transmission Connection Cost Estimate as determined in step 1.8 for that location,~~is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS, plus an estimate of the costs of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station, expressed in Australian million dollars in year t~~;

FFC[t] is the Fixed Fuel Cost as determined in step 1.9;~~is the fixed fuel costs and must represent the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times expressed in Australian million dollars in year t;~~

LC[t] is the Land Cost as determined in step 1.11 for that location~~is the cost of land purchased in year [t]~~; and

WACC is the Weighted Average Cost of Capital as determined in step 1.13.

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1.14.2 Once the IMO has determined a revised value for the Maximum Reserve Capacity Price, the IMO must publish a draft report describing how it has arrived at the proposed revised value **[MR4.16.6]**. In preparing the draft report, the IMO must include details of how it has arrived at any proposed revised values for the Major and Minor components used in calculating the WACC.

1.14.3 The IMO must publish the draft report on the Market Web-site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australian energy industry, including end users.

1.14.4 After considering any submissions on the draft report the IMO must propose a final value for the Maximum Reserve Capacity Price and submit the report to the Economic Regulation Authority (ERA) of Western Australia for approval.

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1.14.5 Once the final value for the Maximum Reserve Capacity Price, with any updates, has been approved by the ERA, the IMO shall post a final report on the IMO website advising of the revised Maximum Reserve Capacity Price.

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1.14.6 The IMO shall publish the Maximum Reserve Capacity Price in the Request for Expressions of Interest document which must be published before 31 January of Year 1 of the relevant Reserve Capacity Cycle.

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1.15 Major Review

1.15.1 In accordance with clause 4.16.9, the IMO must conduct a review of the methodology used to determine the Maximum Reserve Capacity Price at least once every five years ("Major Review"). This process will review the basis for determining the Maximum Reserve Capacity Price, the structural methodology by which the Maximum Reserve Capacity Price is computed each year and the method the IMO uses to estimate each of the constituent components of the Maximum Reserve Capacity Price.

1.15.2 For annual reviews carried out between Major Reviews the IMO must use the same methodology as it used in the most recent Major Review. However, where the IMO considers that any of the comparator companies used in the most recent Major Review are no longer available or that its characteristics have significantly changed, the IMO may select a different set of comparator companies, applying the following criteria:

(a) the company must be a power generator, energy transmitter or distributor;

(b) market capitalisation must be more than $200m AUD; and

(c) the company must be listed on Bloomberg.

Maximum Reserve Capacity Price Basis

1.15.3 The basis of determining the Maximum Reserve Capacity Price shall be reviewed by the IMO with particular reference to the following factors:

(a) The type of power station

(b) The size of the power station

(c) The expected load factor of the power station

(d) Primary and secondary fuel types of the power station.

1.15.4 The above review must give consideration to the Wholesale Electricity Market Objectives.

Power Station

1.15.5 In accordance with Market Rule 4.16.9, the IMO must conduct a review of the definition of the Power Station and its associated components. The IMO is required to take into consideration the following factors:

(a) The method used to determine the Power Station price

(b) The summer derating factor applied to the Power Station

(c) The capacity factor of the Power Station.

Transmission Connection

1.15.6 In accordance with Market Rule 4.16.9, the IMO must conduct a review of the type of connection used to connect the Power Station to the bulk transmission network. The IMO is required to take into consideration the following factors:

(a) Which part of the bulk transmission system the Power Station will be connected to (eg 330kV / 220 kV/ 132 kV).

(b) Land use type assumptions (rural/urban options).

(c) The switchyard configuration.

(d) The number of road crossings.

Fixed Fuel Costs

1.15.7 In accordance with Market Rule 4.16.9 the IMO must conduct a review of the fixed fuel costs with direct reference to the outcome of the review of the Maximum Reserve Capacity Price in s~~S~~tep ~~0~~ 1.15.1 above.