# Review of the Maximum Reserve Capacity Price 2017-2018

INDEPENDENT MARKET OPERATOR

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## Contents

# 1. Introduction

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

The Market Rules require the IMO to conduct a review of the Maximum Reserve Capacity Price (MRCP) each year. As part of this process Jacobs has been commissioned to determine the following for the year 2017-2018:

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

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

# 2. Generation plant capital cost

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

## 2.1 Methodology

To establish the capital cost for a single unit 160 MW OCGT plant the following steps were undertaken:

- Surveyed the gas turbine market for appropriate machines
- Siemens SGT5-2000E (33MAC)[1] with a distillate operation nameplate rating of 178 MW (gross) at ISO[2] conditions was selected as the reference machine for the study. There exist three versions of this gas turbine model, 25MAC, 33MAC and 41MAC. The equipment hardware is identical for each MAC ('Maintenance Concept') model, the difference lies in the firing temperature control which impact the replacement or refurbishment timing of the life-limited, high temperature components such as turbine blades. The timing of scheduled major/minor maintenance intervals is determined by a combination or operating hours, operating mode, fuel type, and cyclic events. For a gas turbine with an expected capacity factor of 2%, a 25MAC or 33MAC version is most likely due to the preference for increased output as opposed to extended high-temperature, part-life. .
  - The Alstom GT13E2 was recently uprated to approximately 200 MW at ISO and therefore not a suitable reference machine.
  - The Mitsubishi 701D has a nameplate capacity of 147 MW at ISO on distillate fuel operation but it is no longer in active production.
  - The General Electric GE 9E.03 (formerly referred to a 9171E) has been recently uprated to 133MW at ISO, but this unit does not meet the base plant criteria.
- Evaporative air cooling technology was selected as the most economic inlet cooling technology based on previous analysis undertaken for the IMO[3] and is consistent with Jacobs' understanding of the technologies commonly adopted for installations in the South West of Western Australia
- Utilised recent, budgetary quotes for main plant equipment pricing and EPC capital costs
- Benchmarked the plant capital costs ($/kW basis) against similar completed projects in Australia including WA and assessed which elements of the costs are fixed and which are scalable to output
- Converted the scalable costs to a $/kW value and used this $/kW to predict the cost of the nominal 160MW unit
- Converted the nominal 160MW plant output to the predicted value at site conditions
- Escalated the historical project cost using appropriate escalation indices[4] (year end to June 2014) for each capital cost component
- Provided the likely net maximum output for the reference machine at 41°C with evaporative cooling, likely humidity conditions and any other relevant factors using SIPEP v5.1 (Siemens Plant Performance Estimation Program.

[1] This is the only gas turbine make/model in production that is rated in close proximity to the 160MW nominal nameplate capacity as per **Appendix B** requirements.
[2] ISO conditions are 15°C ambient dry bulb temperature, 60% relative humidity at 1.013barA atmospheric pressure (typical sea level elevation pressure conditions).
[3] Analysis can be found at http://www.imowa.com.au/docs/default-source/Governance/Market-Advisory-Committee/MAC-Working-Groups/wp04268-rpt-me-001-a_1_capacity_augmentation_on_mrcp_rev1.pdf?sfvrsn=2
[4] Escalation indices were sourced from the Australian Bureau of Statistics for CPI and Labour (Perth based) and commodity indices for steel and concrete.

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

In developing the matrix of costs, Jacobs has utilised:

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

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

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

## 2.2 Project data price review

In developing the end cost estimate, Jacobs utilised reference project data developed for SKM's (now Jacobs') 2013 report to IMO entitled "Review of the Maximum Reserve Capacity Price 2014". This is referenced hereafter as the 2013 report. The reference project consists of Thermoflow GT PRO® heat balance model. The model utilised information garnered from a number of OCGT projects and studies that had been completed in Australia from 2007-2010. Though there have been OCGT projects completed in Australia since 2010, these have been primarily limited to aero-derivative type installations, such as the GE LM6000 and the Rolls-Royce Trent 60, which have a lower individual unit capacities (44 - 64 MW) and higher relative equipment cost ($/kW basis)[5] due to the technology differences. It is also understood that the primary fuel in these installations would be natural gas.

The reference project cost model was updated to reflect current (2014) pricing for main plant equipment, which was provided by Siemens, who confirmed the previous estimate was still valid. The remaining project capital costs components were escalated using various historic (year end to June 2014) escalation indices appropriate to each make-up component of the total capex to provide an estimate in June 2014 dollar terms.

## 2.3 Development of the generic OCGT capital cost estimate

The cost estimate has been based on dual fuel combustor/burner (natural gas and distillate) fitted with dry low emissions (DLE) combustion technology. NOX emissions would typically be in the range of 25 ppmvd at 15% $O_2$ reference conditions when firing natural gas and 42 ppmvd when operating on distillate fuel oil with water injection. Water injection for NOX emissions abatement will be required for liquid fuel operation. The capital cost estimate includes on site water treatment and storage facilities.

The capital costs exclude the distillate fuel oil storage and unloading systems. They are determined separately in **Section 5**. Demineralised water treatment plant, a 1,200 tonne demineralised water storage tank (equivalent to 1,000 tonne of distillate use at a water-to-fuel mass ratio of 1.4:1); and storage capacity for 240 tonnes of potable water plus one hour of fire control water are included in the capital costs. Jacobs notes that the emissions profile of the SGT5-2000E has improved for dry operation on distillate and the water injection rate may therefore be lower than assumed in previous years however this reduction is not yet quantified and he impact of this on cost is not expected to be significant.

[5] Note that all referenced prices are in Australian dollars unless otherwise noted

In addressing any need for water injection requirements, the potential source of the water; the treatment and conditioning of the water to achieve the demineralised quality required for any water injection systems; the on-site storage capacity requirements of such water and the disposal and treatment of effluent from any treatment system have been taken into consideration. However, these assumptions are based on sufficient[6] potable or similar quality water supplies being available local to the facility either through pipe or tanker delivery. The requirements for extensive or complex water abstraction or treatment facilities have not been considered.

## 2.4 OCGT capital cost estimate

A breakdown of the capital cost estimate for the 178 MW reference unit utilising a single OCGT plant is given in **Table 2.1** below. This table shows which elements of the cost are assessed as scalable and which are considered to be fixed. The estimate represents a generic cost for an OCGT plant constructed on an EPC basis. Owner's costs additional to the EPC contract price have been excluded, and are accounted for in the calculation of the term "M" in **Section 7**.

The total capital cost estimate was calculated as **$ 130,251,400** which equates to **800 $/kW**[7] at site conditions.

**Table 2.1 : Generic 178 MW OCGT capital cost estimate**

| Item | Cost [$k] | Type of cost |
|---|---|---|
| Main plant equipment | 71,818.7 | Scalable |
| Balance of plant | 3,200.6 | Scalable |
| Civil works | 16,360.1 | Scalable |
| Mechanical works (including installation) | 9,853.3 | Scalable |
| Electrical works (including installation) | 3,480.8 | Scalable |
| Buildings | 5,732.1 | Fixed |
| Engineering & plant start-up | 4,211.8 | Fixed |
| Contractor's costs | 14,847.1 | Fixed |
| **Total EPC cost** | **$129,504.5** | |

All costs are presented as mean values and are in June 2014 dollars. The reference price for main plant equipment is based upon an EUR/AUD exchange rate of 0.6886.

Jacobs notes that the total cost estimate has increased by approximately **$ 5.8 million** dollars from that estimated in the 2013 report. Only the Siemens SGT5-2000E gas turbine projects were considered as this is now the only currently available gas turbine model within the specified single unit capacity range. The price increase is largely due to a combination of CPI, and change in commodity prices (i.e. steel) between June 2013 and June 2014 and to a lesser extent by the Euro to Australia Dollar exchange rate for the plant and equipment procured from Europe. .

To estimate the capital cost of the nominal 160 MW unit the scalable costs were converted to $/MW and multiplied by the nominal plant output. These were added to the fixed costs to give a total capital cost estimate of $**118,915,500**; which equates to **790 $/MW** at site conditions[8].

## 2.5 Plant output at ISO and required conditions

The unit rating of 178.0 MW running on distillate fuel at full load ('base load'), ISO ambient conditions (15°C, 60% relative humidity) gives a net output of 175.3 MW. At the site conditions (41°C, 30% relative humidity) with evaporative cooling in operation this reduces to a net output of 162.3 MW. The nominal 160 MW unit has a net output of 157.6 MW. At the site conditions (41°C, 30% relative humidity) with evaporative cooling in operation this reduces to a net output of 150.5 MW.

[6] Sufficient quality is defined as potable quality water capable of operating in the evaporative cooler at 2-3 cycles of concentration.
[7] Based on 162.8 MW net output of the reference unit as defined in **Section 2.5**
[8] Based on 150.5 MW net output of the 160 MW unit as defined in **Section 2.5**

In previous reviews for the IMO Maximum Reserve Capacity Price, Jacobs had assumed an evaporative cooling effectiveness of 85% in determining the performance; in this review we have increased the effectiveness to 90% based upon historical tested performance so we consider this a more reasonable figure.  Also, OEMs such as Siemens now quote performance based upon 90% evaporative cooler effectiveness.

The SGT5-2000E performance has been uprated at ISO conditions because there is no longer a 173MW shaft power limit that existed in previous models of this gas turbine.  However, the capacity at site conditions is not materially different.  This leads to a larger load reduction between ISO and site conditions than observed previously.

A summary of these results is provided in **Table 2.2**

**Table 2.2 : SGT5-2000E and nominal 160 MW unit estimated power outputs at ISO and site conditions**

| Unit | ISO conditions | | Site conditions | | Delta |
|---|---|---|---|---|---|
| | MW gross | MW net | MW gross | MW net | net/net |
| SGT5-2000E (2017-18 review)[10] | 178.0 | 175.3 | 164.8 | 162.3 | 7.39% |
| SGT5-2000E (2016-17 review)[11] | 173.0 | 170.8 | 165.2 | 162.8 | 4.68% |
| 160 MW nominal | 160.0 | 157.6 | 152.9 | 150.5 | 4.51% |

[10] Based upon SIPEP v5.1.

[11] Based upon GTPro results for Siemens SGT5-2000E, model ID # 395.  GTPro performance is based upon Siemens SIPEP. The losses include GT and plant auxiliaries, the generator step-up transformer, HVAC and lighting.

# 3. Generation fixed operation & maintenance costs

## 3.1 Assumptions and exclusions

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

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

In accordance with the September 2009 report[12] for the IMO, prepared by MMA in conjunction with Jacobs, the cost of scheduled maintenance overhauls based on number of starts and number of operating hours has been considered as a variable O&M cost, and is not included in this estimate. An allowance for regular balance of plant upkeep and maintenance has been included.

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

## 3.2 Generation operation & maintenance costs

The fixed O&M cost elements shown below in **Table 3.1** have been developed from cost data derived from a range of sources including an amalgam of data from current and recent similar OCGT projects. The addition of evaporative inlet air cooling and associated raw water storage has negligible impact on the fixed balance of plant maintenance costs.

**Table 3.1 : OCGT plant fixed O&M costs**

| O&M cost component | [$k pa] |
|---|---:|
| Plant operator labour | 573 |
| OCGT substation (connection to tie line) | 261 |
| Rates | 63 |
| Balance of plant | 139 |
| Consent (EPA annual charges emissions tests) | 34 |
| Legal | 28 |
| Corporate overhead | 240 |
| Travel | 28 |
| Subcontractors | 377 |
| Engineering support | 73 |
| Security | 138 |
| Electrical (Including control & instrumentation) | 136 |
| Fire | 65 |
| **Total** | **2,155** |

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

These costs have been escalated to June 2014 dollar terms. The costs for statutory reporting requirements, that are common requirements to all generating plants, are inclusive of the costs allocated to the corporate overhead and subcontractor components.

Five yearly aggregate fixed OCGT O&M costs are provided in **Table 3.2** for each five year period of the 30 year operating life.

**Table 3.2 : Fixed OCGT plant O&M costs (June 2014 dollars)**

| Five yearly intervals | 1-5 yrs | 6-10 yrs | 11-15 yrs | 16-20 yrs | 21-25 yrs | 26-30 yrs | 1-30 yrs |
|---|---|---|---|---|---|---|---|
| Fixed O&M costs ($k) | 10,775 | 10,775 | 10,775 | 10,775 | 10,775 | 10,775 | 64,650 |

All costs are presented as mean values.

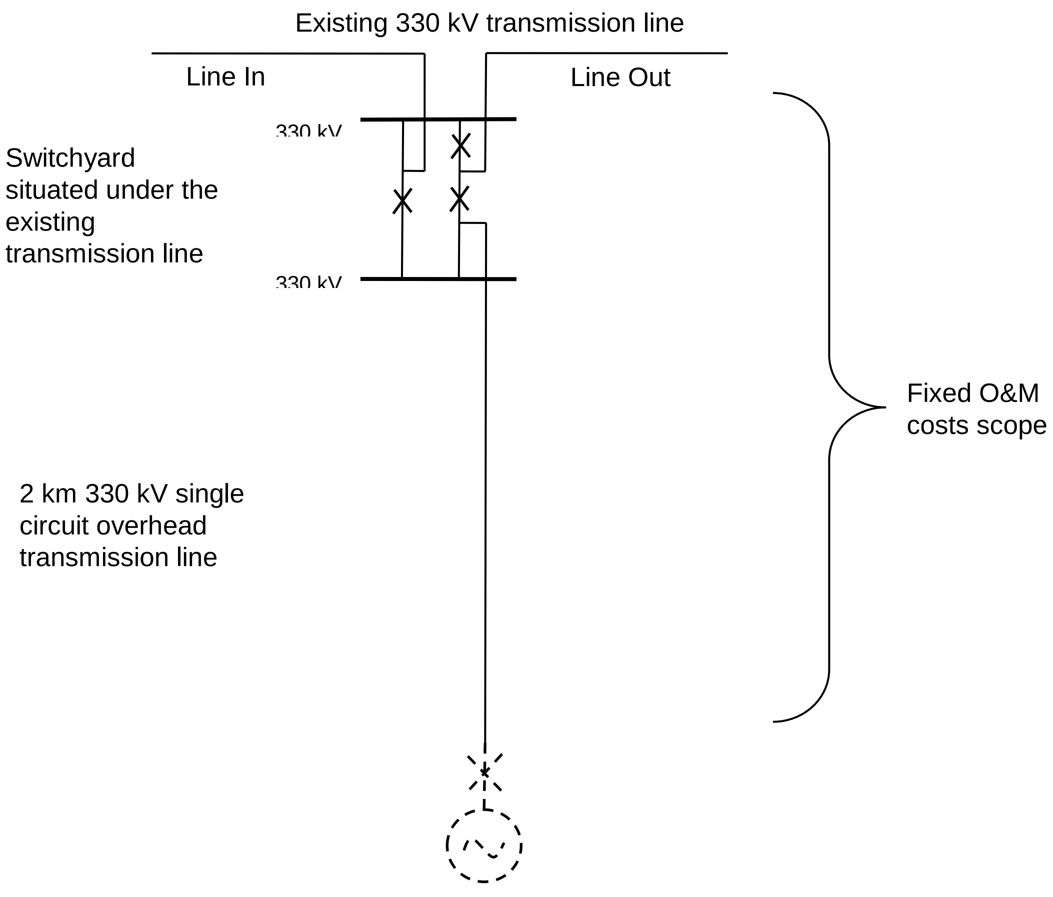
# 4. Connection switchyard and overhead transmission line fixed operation and maintenance costs

## 4.1 General

The connection switchyard fixed O&M costs have been based on the arrangement shown in **Figure 4.1**.

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

**Figure 4.1 : Overall connection arrangement.**




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

## 4.2 Assumptions and exclusions

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

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

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

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

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

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

## 4.3 Switchyard operational & maintenance costs

Jacobs has assumed that the average life of the 330 kV switchyard assets is 50 years. **Table 4.1** shows the fixed O&M costs presented in 5 yearly periods over the lifetime of the switchyard assets. The fixed O&M cost over the asset lifetime for the switchyard is $63,000 pa in June 2014 dollar terms, an increase of $2,500 pa over that determined in the 2013 report.

**Table 4.1 : Five yearly aggregate fixed O&M costs for switchyard assets.**

| Period | Five yearly aggregate fixed switchyard O&M costs (in 2014 $k) |
|---|---|
| 1 to 5 years | 315.0 |
| 6 to 10 years | 315.0 |
| 11 to 15 years | 315.0 |
| 16 to 20 years | 315.0 |
| 21 to 25 years | 315.0 |
| 26 to 30 years | 315.0 |
| 31 to 35 years | 315.0 |
| 36 to 40 years | 315.0 |
| 41 to 45 years | 315.0 |
| 46 to 50 years | 315.0 |

## 4.4 Transmission line operational & maintenance costs

Jacobs has assumed that the average life of the 330 kV transmission line is 60 years. **Table 4.2** shows the fixed operation and maintenance costs presented in 5 yearly periods over the lifetime of the transmission line assets. The fixed O&M cost over the asset lifetime for the transmission line is $1,220 pa in June 2014 dollar terms.

**Table 4.2 : Five yearly aggregate fixed O&M costs for transmission line assets**

| Period | Five yearly aggregate fixed transmission line O&M costs (in 2014 $k) |
|---|---|
| 1 to 5 years | 6.1 |
| 6 to 10 years | 6.1 |
| 11 to 15 years | 6.1 |
| 16 to 20 years | 6.1 |
| 21 to 25 years | 6.1 |
| 26 to 30 years | 6.1 |
| 31 to 35 years | 6.1 |
| 36 to 40 years | 6.1 |
| 41 to 45 years | 6.1 |
| 46 to 50 years | 6.1 |
| 51 to 55 years | 6.1 |
| 56 to 60 years | 6.1 |

# 5. Fixed fuel costs

## 5.1 Introduction

The estimation of the capacity price for 2017-18 includes, as per previous years, costs associated with the fuel supply. The cost is denoted as the Fixed Fuel Cost (FFC) in the Market Procedure.

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

## 5.2 Basis of design

For a breakdown of the basis of design utilised in the estimates for the fixed fuel costs please refer to SKM's "Review of the Maximum Reserve Capacity Price 2013" report. This breakdown was undertaken in some detail and it is considered that an escalation of this price is appropriate as there is no readily comparable new project data.

## 5.3 Fixed fuel cost scope

### 5.3.1 IMO defined requirements

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

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

b) Facilities to receive fuel from road tankers.

c) All associated pipework, pumping and control equipment.

### 5.3.2 Included scope

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

i. Road tanker fuel oil unloading facilities.

ii. Bulk fuel oil storage facilities.

iii. Fuel forwarding and supply facilities.

iv. Oily water treatment and separation equipment.

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

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

vii. Civil and structural works.

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

i. Fuel oil delivery road tanker vehicle unloading / loading connections.

ii. Waste oil collection tanker vehicle loading connections.

iii. Fuel oil supply connection to the OCGT at a single connection point.

iv. Fuel oil return connection from the OCGT at a single connection point.

v. Treated water discharge connection to the site drainage system at a single point local to the fixed fuel oil facility perimeter boundary.

vi. AC power supply connection at the fixed fuel oil facility distribution board equipment.

vii. Earthing connections to the power station earth grid local to the fixed fuel oil facility perimeter boundary.

viii. Control and communications connections at a marshalling panel provided within the fixed fuel oil facility.

## 5.4 Estimated cost

### 5.4.1 Estimate classification

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

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

### 5.4.2 Basis of the estimate

The basis of the capital cost estimate is in accordance with the criteria in “Review of the Maximum Reserve Capacity Price 2013” report. For this report the costs identified in the 2013 report have been escalated to June 2014.

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

### 5.4.3 Fuel facilities costs

The estimated capital cost for the fixed fuel oil facility as presented in this report is **$ 6.05 million**.

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

### 5.4.4 Cost of fuel

The estimated cost of diesel fuel is taken from Jacobs report to IMO entitled “2014 Review of the Energy Price Limits for the Wholesale Electricity Market in the SWIS” dated 5 May 2014). This cost includes delivery transportation but excludes excise and GST.

The Energy Price Limit report identifies a free into store (FIS) price of $1.398 per litre for Pinjar and $1.442 per litre for the Parkeston power station. There is then a deduction of 38.14 cents per litre for the excise and GST components leading to costs of $1.017 and $1.061, respectively.

A mean volumetric cost of $1.04 per litre has been assumed, to be compared with $0.92 in the 2013 report.

To maintain consistency with previous years’ reports, the first fill fuel oil quantity, based on 14 hours operation and an allowance for maintaining a minimum tank working volume, is 815 m3.

The estimated cost of first fill capacity as presented in this report is **$ 0.85 million**.

### 5.4.5 Estimate summary

The estimated capital cost breakdown is summarised as follows:

**Table 5.1 : Estimate summary for fixed fuel system**

| Item description | Cost [$k] |
|---|---|
| Main plant equipment, including installation: | 1,573.5 |
| • main fuel oil storage tank | |

| | |
|---|---|
| Mechanical balance of plant (BoP) equipment, including installation: | 746.2 |
| • fuel oil pump equipment. | |
| • oily water separator equipment. | |
| • piping and fittings | |
| Civil and structural works, including installation | 1,936.5 |
| Electrical and control works, including installation | 450.3 |
| Spares and consumables | 71.3 |
| Engineering, procurement and construction management (12%) | 564.8 |
| Contractor's on-costs, including risk, insurance and profit | 706.0 |
| **Total - fixed fuel oil facility CAPEX** | **6,048.7** |
| **Base fuel storage of 815 m3** | **847.6** |
| **TOTAL** | **6,896.3** |

# 6. Cost escalation forecast

## 6.1 Background

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

Jacobs' cost escalation model has been used extensively in developing cost escalation indices for a number of transmission and distribution network service providers (collectively NSPs or utilities) throughout Australia. The Jacobs cost escalation methodology has also been accepted by the Australian Energy Regulator (AER) in recent revenue proposals submitted by these utilities[13].

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

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

## 6.2 Methodology

This sub-section of the report provides a step-by-step description of the method employed by Jacobs in modelling cost escalation forecasts.

For a power station and associated plant, the primary factors (in no particular order) influencing cost movements are considered to be changes in the following:

- Australian Consumer Price Index (CPI) – as a general price inflation index in itself to convert nominal AUD quotes into real AUD terms (and vice versa) and as a proxy for non-commodity driven cost items.
- Australian EGW Labour Wage Price Index (WPI) – to account for the utilities labour type market.
- Western Australia General Labour WPI – to account for general labour type market.
- Metals – copper and steel prices;
- Foreign exchange rates – primarily the USD to AUD relationship to convert commodities in international market quoted in USD;
- Foreign price inflation index – primarily the US Consumer Price Index (CPI) to convert prices quoted in nominal USD terms into real USD terms (and vice versa). It is noted that this information is required only if the input data sourced from the international market is described in the opposite term to the required term; and
- Australian Engineering Construction Price Index;

The above list is the subset of all the cost drivers that Jacobs maintains in its model. Having identified these key cost drivers, Jacobs examined each of the main items of asset in order to establish a suitable percentage contribution, or weighting, by which each of these underlying cost drivers were considered to influence the total price of each asset item.

[13] Jacobs reports for a number of electricity utilities in the National Electricity Market (NEM) included in their respective recent regulatory submissions to the AER are publically available and can be viewed in the AER's website.

In its determination and application of final cost driver weightings for these assets, Jacobs drew on a wide range of information such as its knowledge of commercial rise and fall clauses contained within confidential client procurement contracts sighted by Jacobs during market price surveys, information passed on during its interviews with equipment suppliers and manufacturers; as well as industry knowledge held within its large internal pool of professional estimators, EPCM project managers, economists, engineers and operational personnel.

With appropriate weightings developed and assigned to each component, the key cost drivers thus provided a means by which changes in the forecast price of each underlying cost driver might be foreseen to affect the overall cost of the asset itself.

**Table 6.1 : Underlying forecast information**

| Cost driver | Application (mostly used for) | Sources |
|---|---|---|
| Australian CPI | To convert nominal AUD to real AUD (and vice versa), various non-commodity driven cost items | Australian Bureau of Statistics (for historic data), and Reserve Bank of Australia and IMO (for forecast trend). |
| Australian EGW labour WPI | To account for specific type of (utilities) labour effort required to build and maintain the asset. | Australian Bureau of Statistics (for historic data), and extrapolation of historic average in the future. |
| Western Australia general labour WPI | To account for general type of labour effort required to build and maintain the asset. | Australian Bureau of Statistics (for historic data), and extrapolation of historic average in the future. |
| Copper prices | Primary equipment, structures, etc. | London Metal Exchange (for historic data and short term forecast trend) and Consensus Economic (for long term forecast trend). |
| Steel prices | Primary equipment, structures, etc. | Consensus Economics (for both historic data, and short term and long term forecast trends). |
| Foreign exchange rates | All forecast commodities price data quoted in international market in USD (to convert USD to AUD). | Reserve Bank of Australia (for historic data), and Reuters (for forecast trend). |
| US CPI | All forecast commodities price data quoted in international market in nominal USD term (to convert nominal USD to real USD and vice versa). | US Bureau of Labour Statistic (for historic data), and US Congressional Budget Office (for forecast trend). |
| Australian Engineering Construction price index | Civil works, foundation, building, establishment etc. | Australian Construction Industry Forum |

## 6.3 Limitation statement

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

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

## 6.4 Individual escalation driver forecasts

### 6.4.1 General

**Table 6.2** presents the forecasted nominal year to June escalation rates for each driver over the next 5 years.

**Table 6.2 : Individual nominal escalation rate forecast year to June for next 5 years**

| | CPI | EGW labour | WA labour | Copper | Steel | Construct |
|---|---|---|---|---|---|---|
| Year to June 2015 | 2.25% | 4.25% | 4.28% | -0.90% | 2.50% | 4.47% |
| Year to June 2016 | 3.00% | 4.25% | 4.28% | 1.74% | 4.93% | 5.31% |
| Year to June 2017 | 2.63% | 4.25% | 4.28% | 1.48% | 1.43% | 4.75% |
| Year to June 2018 | 2.50% | 4.25% | 4.28% | 2.99% | 0.29% | 4.67% |
| Year to June 2019 | 2.50% | 4.25% | 4.28% | 3.19% | 2.46% | 4.65% |

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

### 6.4.2 Australian CPI

Jacobs applies a method of forecasting the position of Australian CPI as accepted by the AER in several recent Final Decisions for electricity NSPs, including the NSW, Queensland and Victorian businesses, in addition to IMO's specific instruction.

This method adopts the following process:

- Plot the most recent actual/ historical quarterly Australian CPI data from the Australian Bureau of Statistic (ABS) record (June 2014 quarter data for this modelling exercise) and determine the annual Australian CPI % change by comparing it to past historical data;
- Plot two and half years of annual Australian CPI % change forecasts from the most recent Reserve Bank of Australia (RBA) Statement on Monetary Policy ( August 2014), with forecast out to December 2016;
- Plot 2.63% as the annual Australian CPI for the year to June 2017 as instructed by the IMO;
- Plot the annual Australian CPI % change as the RBA's inflation target midpoint of 2.5% in long term;
- Apply linear interpolation between the above plotted annual % change points to form a continuous monthly data points for the entire duration of the forecast period; and
- Since this index data is annual measurements and take into account the movements over the previous 12 months, the data point from the last month (i.e. the 12th month data) of the annual period is considered to represent the index level for that year. Also, these data are fairly steady and constant, and generally moves in one predictable direction. Therefore, 'picking' the end 12$^{th}$ month data form an annual period and comparing it with the previous annual period's end 12$^{th}$ month data yields almost the same result as the comparison between the 12 month average from one annual period to 12 month average from the previous annual period.

This annual Australian CPI % change forecast used in Jacobs forecast modelling are presented in **Table 6.3**

**Table 6.3 : Year to June Australian CPI % change forecast**

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| CPI % change | 3.02% | 2.25% | 3.00% | 2.63% | 2.50% | 2.50% |

### 6.4.3 Australian EGW labour

This Australian labour Wage Price Index (WPI) captures the labour cost escalation for Electricity, Gas, Water and Waste water (EGW) or 'Utilities' sector. As this workforce has been in high demand and seen greater than average wage increments in recent times, Jacobs deemed it necessary to separate these costs from general labour.

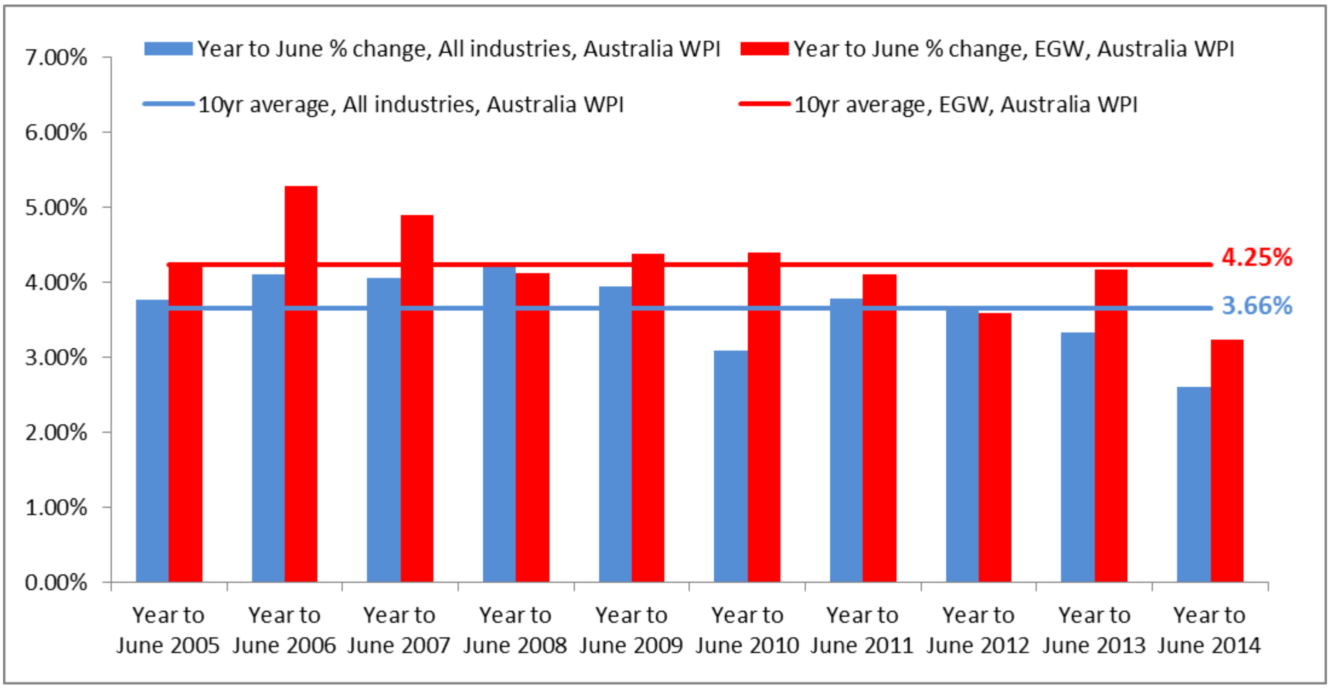
Jacobs used the data published by the Australian Bureau of Statistics (ABS) to develop this cost escalation component. The ABS 6345.0 Wage Price Index; Table 2a to 9a All WPI series: original (financial year index numbers for year ended June quarter); financial year index; total hourly rates of pay excluding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

**Table 6.4** and **Figure 6.1** provide further details of the background data.

**Table 6.4 : Annual change in EGW industries Australia WPI**

| Year To: | EGW industries Australia WPI | Annual change % |
|---|---|---|
| Jun-2004 | 79.9 | |
| Jun-2005 | 83.3 | 4.26% |
| Jun-2006 | 87.7 | 5.28% |
| Jun-2007 | 92.0 | 4.90% |
| Jun-2008 | 95.8 | 4.13% |
| Jun-2009 | 100.0 | 4.38% |
| Jun-2010 | 104.4 | 4.40% |
| Jun-2011 | 108.7 | 4.12% |
| Jun-2012 | 112.6 | 3.59% |
| Jun-2013 | 117.3 | 4.17% |
| Jun-2014 | 121.1 | 3.24% |
| **10 year average % change (2004-2014)** | | **4.25%** |

**Figure 6.1 : Historical annual % change of EGW industries Australia WPI (in comparison to all industries Australia WPI)**




### 6.4.4 Western Australia (WA) labour

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

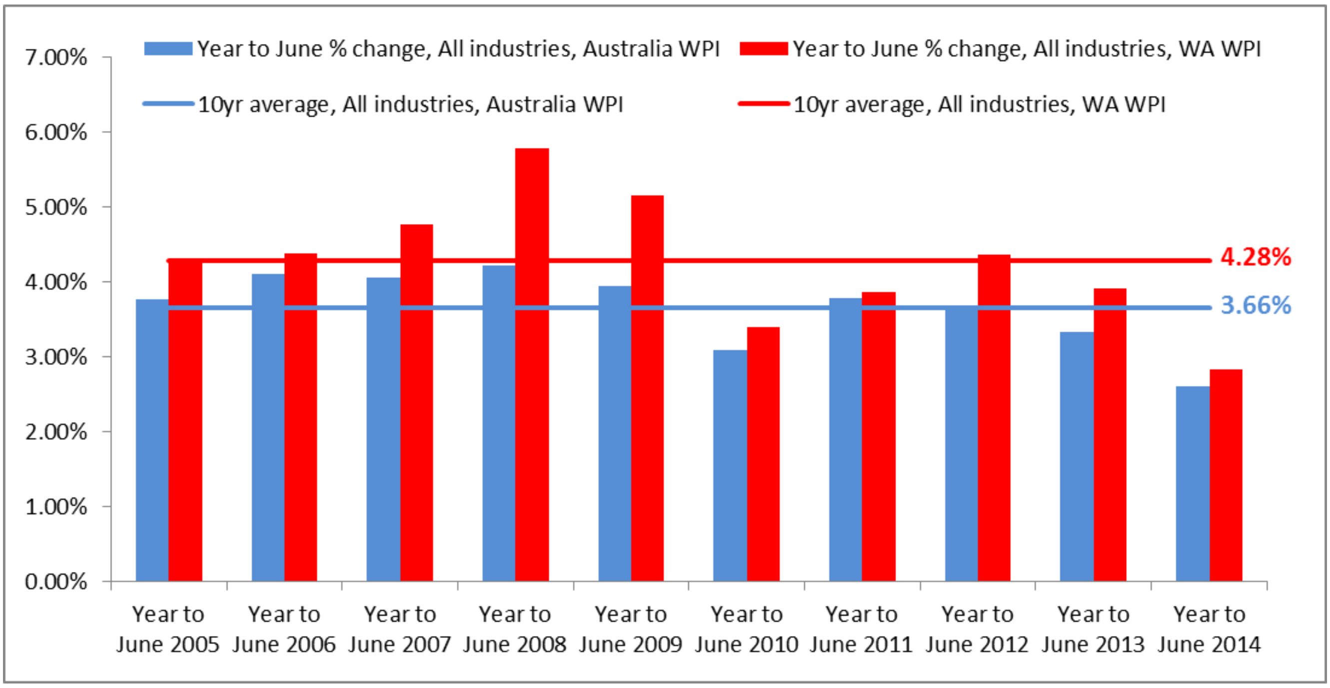
Jacobs again used the data published by the ABS to develop this rate. The ABS 6345.0 Wage Price Index; Table 2a to 9a All WPI series: original (financial year index numbers for year ended June quarter); financial year index; total hourly rates of pay excluding bonuses; Western Australia; private and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

**Table 6.5** and **Figure 6.2** provide further details regarding the background data.

**Table 6.5 : Annual change in all industries WA WPI**

| Year To: | All industries WA WPI | Annual change % |
|---|---|---|
| Jun-2004 | 78.8 | |
| Jun-2005 | 82.2 | 4.31% |
| Jun-2006 | 85.8 | 4.38% |
| Jun-2007 | 89.9 | 4.78% |
| Jun-2008 | 95.1 | 5.78% |
| Jun-2009 | 100.0 | 5.15% |
| Jun-2010 | 103.4 | 3.40% |
| Jun-2011 | 107.4 | 3.87% |
| Jun-2012 | 112.1 | 4.38% |
| Jun-2013 | 116.5 | 3.93% |
| Jun-2014 | 119.8 | 2.83% |
| **10 year average %('04-'13)** | | **4.28%** |

**Figure 6.2 : Historical annual % change in all industries WA WPI (in comparison to all industries Australia WPI)**




### 6.4.5 Australian dollar to US dollar exchange

As internationally traded commodities used in Jacobs' forecasts, such as copper and steel, are traded in nominal US dollars (USD), the Australian dollar's (AUD's) relative position to the USD will, in itself, influence the cost of finished goods to an Australian businesses. The Jacobs' cost escalations modelling process uses the forecast USD/AUD exchange rates, to restate USD based forecast nominal market prices of commodities into their comparable nominal AUD pricing movements. This is undertaken in order to account for any potential movements of base currency commodity market price movements through a strengthening or weakening of the AUD.

The following step, which is in accordance to the AER's preferred method[14], is performed to forecast this economic indicator:

[14] Refer to the AER determination of the most recent SPAusNet electricity transmission network revenue reset, Jan 2014 (available in the AER's website).

- Plot the most recent actual/ historical monthly average USD/AUD exchange rate from the RBA record (August 2014 month data for this modelling exercise), i.e. the average of daily exchange rate from the entire month of August 2014;
- Take an average of daily forward exchange rates (e.g. +1 month, +2 months, +24 months, +36 months, etc.) from the latest available complete month (August 2014) for each forward contract from Reuters, i.e. the average of daily +1 month forward exchange rate from the entire month of August 2014, the average of daily +2 months forward exchange rate from the entire month of August 2014 and so on;
- Thereafter, Jacobs has adopted the longer term historical average of 0.80 USD/AUD exchange rate as the long term forecast going forward; and
- Apply linear interpolation between the months without the most recent historical monthly average exchange rate, forward exchange rates, and long term average exchange rate to form a continuous monthly data points (or exchange rates) for the entire duration of the forecast period.

The annual average of the twelve monthly USD/AUD exchange rate forecast data points as formed in the above steps is presented in the following Table 6.

**Table 6 Forecast annual average USD/AUD exchange rates**

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| USD/AUD (annual average) | 0.919 | 0.922 | 0.901 | 0.885 | 0.873 | 0.861 |

All forecast input pricing data quoted in USD at a future point in time is converted into AUD by using the USD/AUD exchange rate forecast from the same point in time.

### 6.4.6 Copper

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

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

An example of the application of Jacobs' methodology is the process for developing future price positions for commodity based cost drivers such as aluminium, copper and oil, within the Jacobs' Cost Escalation Model.

In this instance the process applied by Jacobs uses an eight step approach. This approach is followed in order to produce specific data points between which linear interpolation is applied in order to fill in any missing data points and arrive at the required market pricing positions. Jacobs' Cost Escalation Model has a resolution of one month, and all prices are determined monthly, with annual averages used to smooth volatility from month to month.

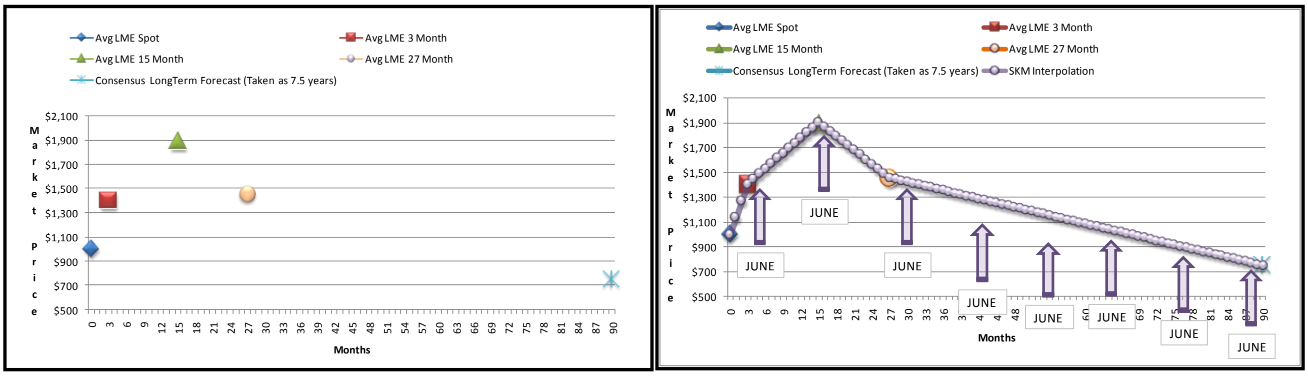
Due to the volatility in daily spot and futures markets, Jacobs uses monthly prices within its modelling process as the basis for developing its forecasts. The use of 12 monthly prices to determine annual average price assists to ensure that future prices are neither unnecessarily inflated, nor deflated, through the application of a particular monthly peak, or trough, during the interpolation of prices for the commodity in question. The eight steps involved are:

- Plot the daily average of the latest available complete month (August 2014) of London Metal Exchange (LME) spot prices;
- Plot the August 2014 daily average of the LME 3 month prices;
- Plot the August 2014 daily average of the LME December year 1 prices;
- Plot the August 2014 daily average of the LME December year 2 prices;

- Plot the August 2014 daily average of the LME December year 3 prices;
- Plot the August 2014 Consensus Economics Long Term forecast position (taken as 7.5 years from the survey date)15;
- Apply linear interpolation between the plot points; and
- Since this price data trend fluctuate frequently and in both directions (increase or decrease), the year-to-June average (i.e. 12 months average) price data is considered to represent the price level for that July to June annual period.

This method is illustrated in Figure 6.3 (*note that the figures are illustrative only and do not refer to the actual position/price of any particular commodity*).

**Figure 6.3 : Diagram of method (illustrative only). Steps 1-6 (left) and steps 7-8 (right)**




The average year to June input numbers used during Jacobs' escalation modelling of the copper nominal prices are presented in **Table 6.7**. It has been converted to Australian dollars.

**Table 6.7 : Forecast average annual copper price (AU$/tonne nominal)**

| Year to June | 2013 A | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|---|
| Copper price | $7,464 | $7,641 | $7,572 | $7,704 | $7,818 | $8,052 | $8,309 |
| % Annual change | | 2.37% | -0.90% | 1.74% | 1.48% | 2.99% | 3.19% |

### 6.4.7 Steel

Jacobs' methodology used for developing forward market positions for copper and aluminium is presently not considered suitable for steel, due to the lack of a liquid or a benchmark steel futures market. Jacobs notes that the LME commenced trading in steel billet futures in February 2008 and the available future contract prices are applicable only for delivery to Dubai and Turkey[16]. While the steel billet is a semi-finished product, its price movement has a strong correlation with the end product like steel reinforcement bar (used for construction), and therefore its forecast or future price trend can be used to calculate the escalation rate for steel[17]. However, one of the limitations for using the LME forecast prices for steel billet is the unavailability of a longer term trend (prices available up to 15 months only). Further the current global production of steel averages 1,400 million tonnes per annum and the LME steel billet futures have a traded volume of approximately six million tonnes per annum, less than 0.5% of the global market.

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

[15] 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, Jacobs consider the position to refer to the mid-point of this range, being 7.5 years, or 90 months hence.
[16] http://www.lme.co.uk/5723.asp
[17] http://www.lme.com/steel-faqs.asp

Jacobs has used the August 2014 Consensus Economics survey report to compile the steel price escalation information provided in this report. This publication provided quarterly forecast market prices for steel from present month (i.e. August 2014) to +29 months, as well as a long-term forecast pricing position i.e. annual average of +3 years, +4 years, +5 years, and 5–10 year position which is taken as 7.5 years (90 months) from survey date.

Consensus Economics provides two separate forecasts for steel, using Hot Rolled Coil (HRC) steel prices in the USA domestic market and the other the European domestic market. Both forecasts are quoted in US$. The Consensus Economics US HRC price forecasts are presented in US$ per *Short Ton*, which Jacobs converts into US$ per *Metric Tonne* for consistency with the European price.

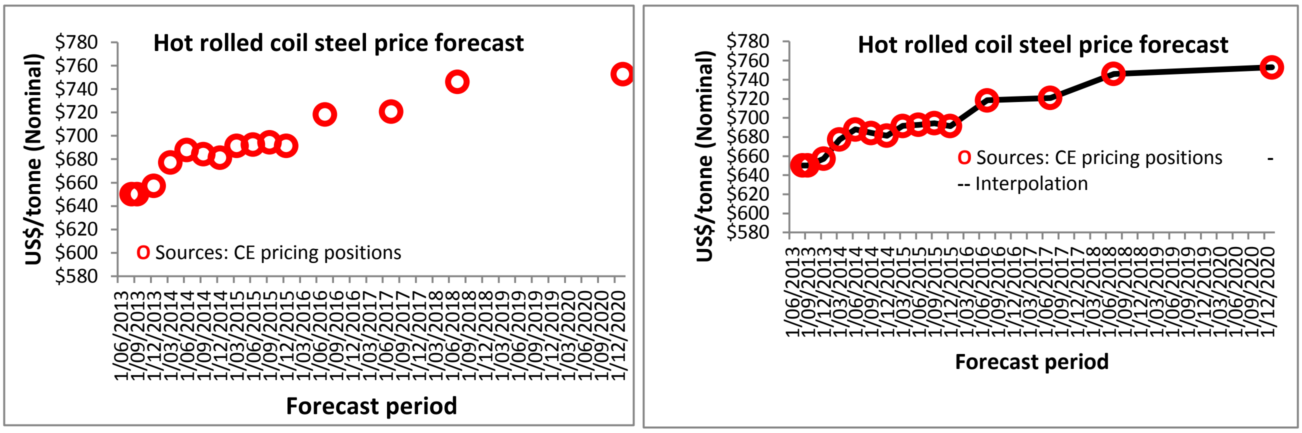
Jacobs undertakes a seventeen step approach to produce specific data points between which linear interpolation is applied in order to fill in any missing data points and arrive at the year to June annual average pricing positions for steel.

Due to the volatility in daily spot and futures markets, Jacobs uses monthly average of these two forecasts (US HRC and EU HRC) as its steel price inputs to the cost escalation modelling process. The use of 12 monthly average prices to determine annual average price assists to ensure that future prices are neither unnecessarily inflated, nor deflated, through the application of a particular monthly peak, or trough, during the interpolation of prices for the commodity in question. The seventeen steps involved are:

- Plot the latest available average of US and European CE spot prices;
- Plot the average of US and European CE 2 month prices;
- Plot the average of US and European CE 5 month prices;
- Plot the average of US and European CE 8 month prices;
- Plot the average of US and European CE 11 month prices;
- Plot the average of US and European CE 14 month prices;
- Plot the average of US and European CE 17 month prices;
- Plot the average of US and European CE 20 month prices;
- Plot the average of US and European CE 23 month prices;
- Plot the average of US and European CE 26 month prices;
- Plot the average of US and European CE 29 month prices;
- Plot the average of US and European CE 36 month prices;
- Plot the average of US and European CE 48 month prices;
- Plot the average of US and European CE 60 month prices;
- Plot the average of US and European Consensus Economics long term forecast position (taken as 7.5 years from the survey date);
- Apply linear interpolation between the plot points; and
- Since this price data trend fluctuate frequently and in both directions (increase or decrease), the year-to-June average (i.e. 12 months average) price data is considered to represent the price level for that July to June annual period.

This methodology is illustrated in **Figure 6.4** (*note that the figures are illustrative only and do not refer to the actual position/price for any particular period*).

**Figure 6.4 : Diagram of method (illustrative only). Steps 1-15 (left) and steps 16-17 (right)**




The average year to June input numbers used during Jacobs' escalation modelling of the steel nominal prices are presented in **Table 6.8**. It has been converted to Australian dollar.

**Table 6.8 : Forecasted average annual steel price (AU$/metric tonne nominal)**

| Year to June | 2013 A | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|---|
| Steel Price | $640 | $705 | $723 | $758 | $769 | $772 | $791 |
| % Annual Change | | 10.26% | 2.50% | 4.93% | 1.43% | 0.29% | 2.46% |

### 6.4.8 Engineering construction

The Australian Construction Industry Forum (ACIF)[18] is the peak consultative organisation of the building and construction sectors in Australia. The ACIF has established the Construction Forecasting Council (CFC)[19] through which it provides a tool kit of analysis and information. Jacobs referred to a range of forecast trends generated by the CFC as a proxy for the future movement in the price of civil work or engineering type construction work in the WA market.

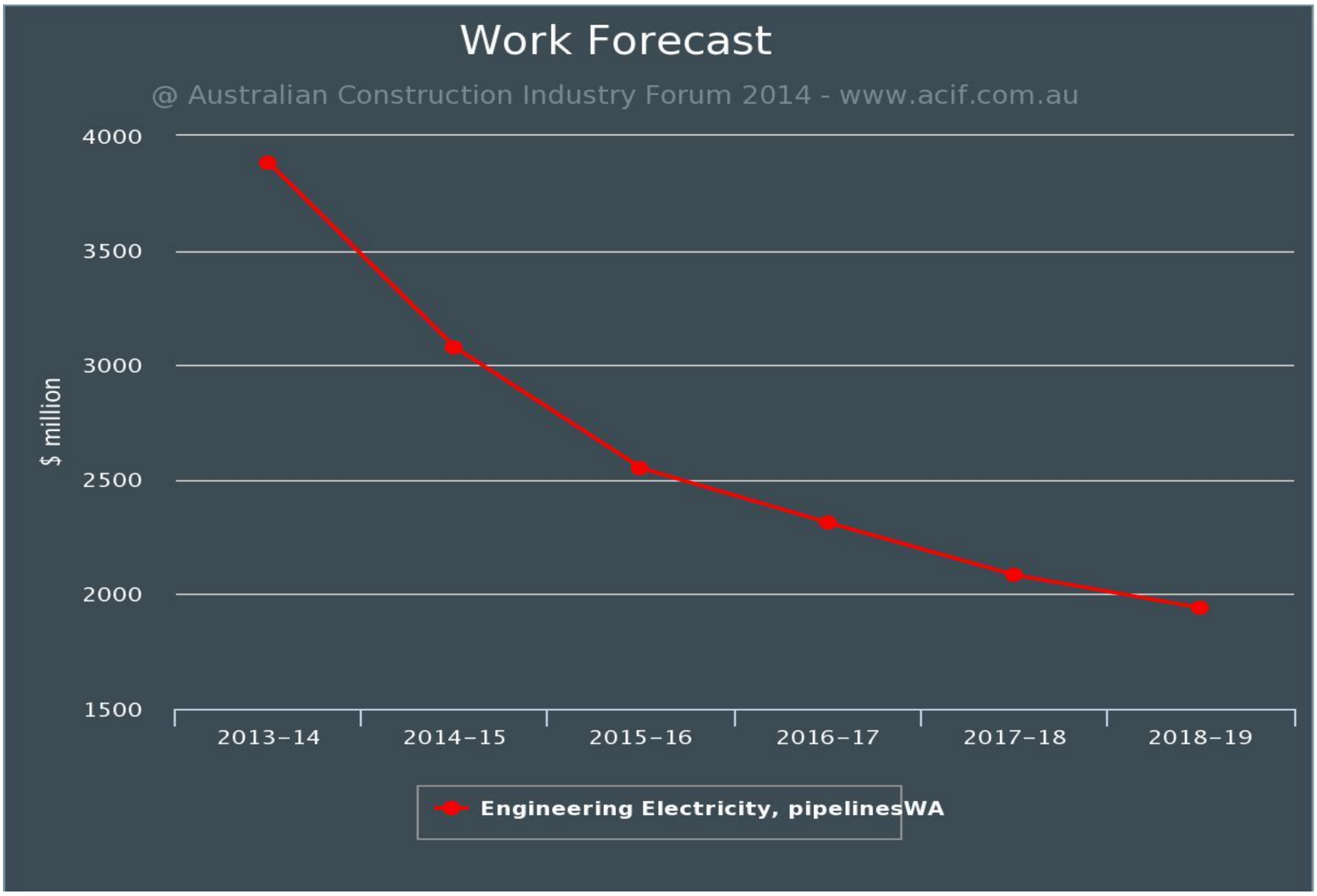
In commenting on construction activity in WA and those related to the engineering industry, the CFC in its most recent commentary (dated May 2014) notes the following:

> *"ACIF projects spending in engineering construction to peak in 2014-15, followed by a gradual decline as major resource projects come to an end. Although spending will fall quickly at first, the downward trend will likely flatten out at levels well above the historical average.*
>
> *Non residential building activity has grown strongly as support services demand grew with the rise of mining townships and rapid population growth. We anticipate these activities to slow down and trend at close to zero growth through to 2022-23.[20]"*
>
> *"ACIF projects that although a downturn in Engineering Construction activity is unavoidable following 2013-14 for several years, this will not be as rapid as the historical surge in spending observed over the past decade.[21]".*

These statements along with the commentary on construction activities related to heavy industry are illustrated in **Figure 6.5** which shows forecast trends of capital expenditure volume in WA.

[18] http://www.acif.com.au/
[19] http://www.cfc.acif.com.au/cfcinfo.asp
[20] http://www.acif.com.au/forecasts/summary/state-comparisons
[21] http://www.acif.com.au/forecasts/summary/highlights-for-engineering-construction

**Figure 6.5 : Engineering (electricity & pipeline) construction volume in WA**




The CFC also provides forecasts of the price index related to 'engineering' construction category for overall Australia region. The following steps are performed to forecast this economic indicator:

- Plot the most recent actual/ historical and forecast annual 'Engineering' construction price index from the CFC's toolkit (May 2014);
- Apply linear interpolation between the above plotted index to form continuous monthly data points for the entire duration of the forecast period; and
- Since this index data is annual measurements and takes into account the movements over the previous 12 months, the data point from the last month (i.e. the 12$^{th}$ month data) of the annual period is considered to represent the index level for that year. Also, these data are fairly steady and constant, and generally moves in one predictable direction. Therefore, 'picking' the end 12$^{th}$ month data from an annual period and comparing it with the previous annual period's end 12$^{th}$ month data yields almost the same result as the comparison between the 12 month average from one annual period to 12 month average from the previous annual period.

**Table 6.9** provides the relative excerpt of the CFC Australian Engineering Construction Price Index, based on the most recent data available in May 2014. CFC publishes its forecast price index in real terms and Jacobs has converted these to nominal terms for modelling purposes.

**Table 6.9 : Australia wide engineering construction escalation factor forecast**

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| Real Price Index | 1.0130 | 1.0217 | 1.0225 | 1.0220 | 1.0212 | 1.0210 |
| Australian CPI % change | 3.02% | 2.25% | 3.00% | 2.50% | 2.50% | 2.50% |
| Nominal Price Index | 1.0436 | 1.0447 | 1.0531 | 1.0475 | 1.0467 | 1.0465 |

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| Nominal Price Index % change | 4.36% | 4.47% | 5.31% | 4.75% | 4.67% | 4.65% |

## 6.5 Weighting of the cost drivers

An understanding of the appropriate application of weighting for each cost driver to each item of plant and equipment has been developed by Jacobs over time as a result of in- house knowledge, project experience and advice from Jacobs' team of professional economists and engineers.

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

## 6.6 Capital cost escalation factors

The final aggregated nominal capital cost escalation factors determined by Jacobs for the annual forecast year to end of June for the next 5 years are shown in **Table 6.10**.

**Table 6.10 : Nominal capital cost composite escalation factor annual forecast year to June for next 5 years**

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| Power station | 2.25% | 2.97% | 4.00% | 3.10% | 3.00% | 3.51% |

The aggregated nominal escalation factors in this table are the resulting averages of the cost driver indices weighted by the cost items makeup proportion of the respective capital costs estimated in this report in June 2014 dollar value. For example, the component makeup of the power station capital cost estimate appears in **Table 2.1** of this report. Each of the listed cost items is influenced by multiple underlying commodity cost driver indices in different proportions.

Using the escalation factors in **Table 6.10**, the total capital cost estimate of the power station on **1 April 2017** is forecasted as **$ 130,305,100** which equates to **866 $/kW**[22] . This forecast estimate is as per Section 2.3.1 (a) of the Market Procedure for MRCP (version 6) which requires the estimate as at April in Year 3 of the Reserve Capacity Cycle.

## 6.7 Fixed operational & maintenance cost escalation factors

The final aggregated nominal operating cost escalation factors determined by Jacobs for the annual forecast year to June for the next 5 years are shown in **Table 6.11**.

**Table 6.11 : Nominal fixed O&M cost composite escalation factor annual forecast year to June for next 5 years**

| Year to June | 2014 A | 2015 F | 2016 F | 2017 F | 2018 F | 2019 F |
|---|---|---|---|---|---|---|
| Power station | 3.06% | 3.54% | 3.82% | 3.69% | 3.65% | 3.65% |
| Connection switchyard | 3.24% | 4.25% | 4.25% | 4.25% | 4.25% | 4.25% |
| Overhead transmission line | 3.24% | 4.25% | 4.25% | 4.25% | 4.25% | 4.25% |

The fixed O&M cost escalation factors for the connection switchyard and the overhead transmission line follow the Australian Electricity Gas Water Labour Price Index. The aggregated fixed O&M cost escalation factor for the power station is the resulting average of the cost driver indices weighted by its cost items makeup proportion estimated in this report in June 2014 dollar value. The makeup components of the power station fixed O&M cost appears in **Table 3.1** of this report. Each of the listed cost items is influenced by one or multiple cost driver indices.

Using the escalation factors in **Table 6.11**, the fixed O&M cost estimate of the power station in **October 2017** is forecasted as **$ 2.424 million per annum** (or $ 12.12 million for a 5 years period in Oct 2017 dollars).

[22] Based on 150.5 MW net output as defined in **Section 2.5**.

Similarly, the fixed O&M cost estimate of the connection switchyard and the overhead transmission line in **October 2017** are **$ 72,132 per annum** (or $ 360,258 for a 5 years period in Oct 2017 dollar) and **$ 1,397 per annum** (or $ 6,984 for a 5 years period in Oct 2017 dollars) respectively.

These forecast estimates are as per Section 2.5.6 (a) of the Market Procedure for MRCP (version 6) which requires the fixed O&M estimates as at October in Year 3 of the Reserve Capacity Cycle.

# 7. Calculation of the M factor

## 7.1 Introduction

The allowance, M, to be included for “Legal, Insurance, Approvals, Other Costs and Contingencies” is to be estimated in accordance with Section 2.8 of the Market Procedure as:

*The IMO shall engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:*

*(a) Legal costs associated with the design and construction of the power station;*

*(b) Financing costs associated with equity raising;*

*(c) Insurance costs associated with the project development phase;*

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

*(e) Other costs reasonably incurred in the design and management of the power station construction; and*

*(f) Contingency cost*s.

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

## 7.2 Implications of the specified procedure

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

- The costs are based on the costs to develop a single Siemens SGT5-2000E liquid fuelled gas turbine plant re-valued to a nominal capacity of 160 MW. When calculating specific costs the capacity at 41°C is considered.
- The plant operates at a low capacity factor (2%).
- The plant would be developed upon industrial land. The nominated locales are areas where existing similar plants are located and other industrial facilities:
  - Collie Region.
  - Kemerton Industrial Park Region.
  - Pinjar Region.
  - Kwinana Region.
  - North Country Region.
  - Kalgoorlie Region.
- The costs of acquiring land are excluded from the M parameter.
- The power plant is delivered on a single package, turnkey EPC contract.
- The power plant costs are estimated based on a notional project being committed at the current time. The commissioning time may be of the order of three years in the future to coincide with the period the capacity auction was undertaken for. Since the delivery time of such a gas turbine can be up to 2 years from the time of EPC contract closure, the factors should consider that prices for plant etc may be subject to 1 year of variation between the time of the auction and the time of financial closure of the EPC contract.

- The procedure is not explicit in identifying whether a project financed model or a corporate financed model of the power station development should be assumed. The discussion in the procedure regarding the project being eligible to receive a ‘Long Term Special Price Arrangement’ suggests project finance whereas the relatively low debt issuance cost prescribed (12.5bp) and the specification for comparator companies in the WACC review suggest corporate finance. The project development costs for a project financed project tend to be higher due to additional processes undertaken (preparation, issue and attendance upon Information Memoranda, debt syndication, due diligence reviews, etc.). It is considered appropriate that the form of financing model be more appropriately considered within the development of the WACC parameter than within the M parameter.
- The recognition of costs attributable to the project development commences at the time of the auction that is taken to be approximately 1 year before financial close and prior to approval and procurement processes being undertaken. The cost of these processes is thus included within the M factor.

## 7.3 Values applied in 2013 report

Costs for indirect capital cost elements vary widely between projects and there is a lack of specific data from the WA market. Consideration is given to the 2013 report scope and values and whether any changes are considered appropriate in this 2014 review.

The parameters applied in the 2013 review for the M factor are listed in **Table 7.1**. These components are discussed below.

**Table 7.1 : Calculation of the M factor in 2013**

| Component of ‘M’ | 2013 % of EPC | 2013 $k |
|---|---|---|
| Project management | 2.07% | $2,410 |
| Project insurance | 0.5% | $581 |
| Cost of raising capital | 3.00% | $3,489 |
| Environmental approvals | 0.86% | $1,000 |
| Legal costs | 1.34% | $1,554 |
| Owner’s engineer - part A (including concept design, specification, tendering, contract negotiations) | 0.46% | $535 |
| Owner’s engineer - part B (including construction phase OE costs, oversee project, witness tests & commissioning) | 3.22% | $3,748 |
| Initial spares requirements | 0.80% | $930 |
| Site services (provision of potable water, construction power, communications, domestic sewerage etc. at site) | 0.1% | $116 |
| Start-up costs | 2.75% | $3,198 |
| Contingencies | 5.00% | $5,815 |
| **Total M** | **20.10%** | **$23,376** |

These were applied to a base EPC capex estimate of $ 116.3 million in 2013. The following analysis is based on the June 2014 estimate of $ 118.9 million.

The prescribed method is unchanged from the 2013 report update.

## 7.4 Derivation of the M factor in 2014

### 7.4.1 Project management and owner's engineering

These costs typically are made up of consulting engineering services and have been broken down into three components – project management by the developer / owner and owner's engineering costs which may be via a contract with a services provider. The latter are separated into pre and post commitment costs. As before, we have used the producer price indices to escalate the 2013 report costs. The change in producer price indices (PPI) (Australia wide) for "Engineering design and engineering consulting services" from June 2013 to June 2014 has been 1.5%[23].

### 7.4.2 Legal

The legal costs allowed in 2013 amounted to $ 1.56 million. This would be expected to cover a full service such as for a project financed project. For a corporate financed project, delivered on an EPC basis, the project agreements are more limited (EPC, connection agreement, loan agreement, land purchase, fuel supply agreement, etc.). The allowance previously applied should suffice.

The 2013 report amount has been escalated at the PPI rate for "Legal services" of 1.8%[24].

### 7.4.3 Insurance

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

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

An allowance of 0.5% has been provided in the margin M to cater for these costs. This is in line with the 2012 and 2013 reports which had an increase from the 2011 report due to market information on increases in insurance premiums.

### 7.4.4 Approvals

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

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

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

[23] ABS "6427.0 Producer Price Indexes, Australia", Table 24. Selected output of division M professional, scientific and technical services, group and class index numbers, Series A2314202T.
[24] ABS op cit, Series A2314223C.

If the project is assigned a PER level of assessment the amount of work can be far more significant. In addition to the above, the project may require detailed environmental studies relevant to the project area, community consultation, as well as a significant review and response to comment period. Indicative costs would be in the order of $ 600K to $ 2.0 million for this level, depending upon the significance of the environmental factors.

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

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

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

For this review a midrange allowance of $ 1.0 million is applied. This is unchanged from the 2012 and 20134 reports.

### 7.4.5 Financing costs associated with equity raising

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

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

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

In the 2013 report an allowance of 3% was provided for the “Cost of raising capital”, on the basis this was equity raising costs only (a debt issuance cost being included within the WACC).

The allowance of approximately 3% is still considered appropriate.

### 7.4.6 Initial spares and site services

The 2013 report allowances for initial spares of 0.8% and for site services of 0.1% are considered reasonable.

### 7.4.7 Start-up costs

Start-up costs were considered for the first time in 2012 and reassessed in the 2012 and 2013 reports. For an OCGT plant the primary start-up costs would include:

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

The 2013 report update showed an increase from the previous allowance for start-up costs of 2% as there was evidence that this value is too low as it did not consider all compliance testing requirements including:

- Environmental licence compliance
- Compliance with Western Power under the Technical Rules.

The 2013 report revised value of 2.75% is still considered appropriate. This change increases the cost from $ 3.2 million to $ 3.3 million.

### 7.4.8 Contingency costs

The “contingency” allowed in the 2012 and 2013 reports was 5%, reflecting an allowance for minor and unidentified items. These could include things such as undetected latent conditions, risk of contractor insolvency, unseasonal or divergent weather patterns, pre-work on the site prior to the EPC contract (e.g. access, fencing/security, removal of debris or contamination etc to facilitate studies), special tools etc.

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

## 7.5 Overall M factor

The M factor resulting from this analysis is given in **Table 7.2**.

**Table 7.2 : Calculation of M factor in 2014**

| Component of ‘M’ | 2013 % of EPC | 2014 % of EPC | 2014 $k |
|---|---|---|---|
| Project management | 2.07% | 2.06% | $2,446 |
| Project insurance | 0.50% | 0.50% | $595 |
| Cost of raising capital | 3.00% | 3.00% | $3,489 |
| Environmental approvals | 0.86% | 0.84% | $1,000 |
| Legal costs | 1.34% | 1.33% | $1,582 |
| Owner’s engineer - part A (including concept design, specification, tendering, contract negotiations) | 0.46% | 0.46% | $543 |
| Owner’s engineer - part B (including construction phase OE costs, oversee project, witness tests & commissioning) | 3.22% | 3.20% | $3,804 |
| Initial spares requirements | 0.80% | 0.80% | $951 |
| Site services (provision of potable water, construction power, communications, domestic sewerage etc. at site) | 0.10% | 0.10% | $119 |
| Start-up costs | 2.75% | 2.75% | $3,270 |
| Contingencies | 5.00% | 5.00% | $5,946 |
| **Total M** | **20.10%** | **19.97%** | **$23,744** |

As noted above, the 160 MW OCGT plant capital cost estimate and ‘M’ factor combined are calculated to reflect a “most likely” outcome, consistent with Jacobs’ interpretation of the scope of work.

# Appendix A. Estimate Classification Criteria

**APPENDIX B2 ESTIMATE CLASSIFICATION CRITERIA**

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

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

# Appendix B. Scope of work

## B.1 Project scope

Jacobs shall provide the following estimates and information.

### B.1.1 Development of costs for the power station

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

h) Include the minimum level of equipment or systems required to satisfy the Balancing Facility Requirements

### B.1.2 Fixed operating and maintenance costs

1) Fixed Operating and Maintenance (O&M) costs for the Power Station inclusive of the following items:

   a) Plant operator labour;

   b) OCGT substation (connection to tie line);

   c) Rates;

   d) Market fee;

   e) Balance of plant;

   f) Consent (EPA annual charges emission tests);

   g) Legal;

   h) Corporate overhead;

   i) Travel;

   j) Subcontractors;

   k) Engineering support;

   l) Security;

   m) Electrical (including Control & Instrumentation); and

   n) Fire Detection and Protection Systems.

2) Fixed Operating and Maintenance (O&M) costs for the associated transmission connection work (i.e. the overhead transmission line and the connection switchyard) inclusive of the following items:

   a) Cost of labour for routine maintenance;

   b) Cost of machine/plant/tool hire for routine maintenance; and

   c) Overhead (management, administration, operation etc).

3) It is noted that Jacobs will not provide an estimate of annual asset insurance cost required to insure the replacement of power station capital equipment, infrastructure, and associated transmission connection work.

4) The estimated fixed O&M cost will not allow for defect or asset replacement during the lifetime of the assets.

5) Jacobs notes that the maintenance cost for an asset is incurred periodically according to its maintenance routines. Since this routine is different for different asset classes, Jacobs will smooth these period costs evenly over the life of the power station, transmission line and connection switchyard and convert into an annualised fixed O&M costs.

6) To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component shall be presented for each 5 year period up to 60 years.

7) Fixed O&M costs must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using the following escalation factors which shall be provided as part of the advice provided under scope B.1.2 and applied to relevant components within the Fixed O&M cost:

   a) Generation O&M Cost escalation factor for Generation O&M costs;

   b) a Labour cost escalation factor for transmission and switchyard O&M costs; and

   c) CPI for fixed network access and/or ongoing charges determined with regard to the forecasts of the Australian Bureau of Statistics and, beyond the period of any such forecasts, the mid-point of the ABS's target range of inflation.

### B.1.3 Fixed fuel cost

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

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

1) The IMO shall engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:
   a) legal costs associated with the design and construction of the power station;
   b) financing costs associated with equity raising;
   c) insurance costs associated with the project development phase;
   d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;
   e) other costs reasonably incurred in the design and management of the power station construction; and
   f) Contingency costs