ADDENDUM

**Prepared For:**

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# Addendum to CRA International's report on Western Power's Regulatory Test application for the Mid-West Region

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## CONFIDENTIAL MATERIAL

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# 1. INTRODUCTION

Further to the CRA International Report of 30 March 2007,[1] Western Power has asked us to consider the following issues that have arisen subsequent to its augmentation proposal for the Mid-West region under the Regulatory Test:

- The validity of PB Associates conclusion that major augmentation in the Mid-West region may be deferred by up to 2 years;
- The impact on the rank ordering analysis of introducing an additional augmentation option ("Option 2d"); and
- The likely economic costs associated with the development of an island-grid option (Option 11).

# 2. OVERVIEW OF PB ASSOCIATES APPROACH TO DEMAND FORECASTING

PB Associates concludes that there may exist an opportunity to defer major augmentation in the Mid-West region for up to two years:[2]

> *Analysis using uncertainty methods suggests that demand increases are likely to occur more gradually than anticipated by Western Power in which case an opportunity may exist to defer the decision to proceed with a major augmentation for one to two years.*

PB Associates conclusion is at odds with Western Power's Regulatory Test application and the data used in the accompanying CRA International report. Even under its lowest growth scenario (natural growth) Western Power data showed a need for augmentation by 2009-10, with limited potential to defer 330kV augmentation.

PB Associates had access to the same data used by Western Power. Although it is not possible to verify PB Associates results from its report, the reason for the different conclusions appears to relate to the forecasting methodology for natural load growth and the modelling of new block loads.

1 CRA International, "Reinforcement Options for the North Country Region", 30 March 2007.

2 Parsons Brinkerhoff Associates, "Technical Appraisal of Western Power's Major Augmentation Proposal for a 330kV Transmission Line & Associated Works in the Mid-West region of Western Australia", 29 October 2007, p.1.

## 2.1. TREATMENT OF NATURAL LOAD GROWTH

PB Associates notes that it derives a forecast for natural load growth using Monte Carlo analysis. In doing so, random samples are drawn from a distribution containing the mean and standard deviation of the logarithm of the year-on-year growth rates between 1998 and 2007.[3]

Monte Carlo analysis provides a useful tool for demand forecasting. However, the results from Monte Carlo analysis are only as good as the assumptions underpinning the implied methodology. PB Associates appears to obtain a lower natural growth rate than Western Power not because it has used Monte Carlo analysis, but because it effectively constrains demand post-2007 to increase at a similar rate to the 1998-2007 historical average.

The base or natural forecast is a key input for the Regulatory Test as the potential to defer augmentation may be highly sensitive to small changes in natural load growth. Western Power incorporates the following features in its natural load forecast:

- A sharp increase in actual load during 2007, much of which was forecast at the time of initial assessment (December 2006); and
- The inclusion of new block loads that Western Power has committed to supply from 2008 and beyond that represent step changes in load rather than part of a trend increase.

Therefore by assuming that historical growth rates will, on average, continue and excluding committed new block loads, PB Associates approach is highly likely to understate the growth of “natural” demand. PB Associates appears to forecast a similar post-2008 growth in natural load as Western Power. Therefore, if PB Associates natural growth forecast is adjusted for higher demand in 2007 and the new block loads the PB Associates forecast of natural demand forecast will be similar to that of Western Power.

In our earlier analysis we found that even under the Western Power “low demand” or natural growth scenario there was a need for augmentation in 2009-10 and that Option 1 met the need for augmentation at lowest cost. Option 1 became more dominant when the possibility of future block loads was introduced.

Western Power has subsequently revised its natural growth forecast upwards. Any upward revision to the demand forecast will only further reinforce the conclusion that there is limited, if any, scope to defer augmentation and that Option 1 is the dominant option.

3 Ibid, p.9.

## 2.2. APPROACH TO MODELLING BLOCK LOADS

If the above problems with PB Associates approach to forecasting natural load are corrected then the approach to modelling block loads becomes somewhat second-order. This is because the data shows a need for augmentation in 2009-10 under all demand scenarios and shows that Option 1 provides the highest net benefit in all cases.

Western Power and PB Associates adopt different approach to modelling block loads.

Western Power assigns an expected start date and probability for each block load. The high forecast assumes that all block loads are commissioned. The central forecast applies a probability weighted load. For example, if a proposed 100MW load has a 70% probability, then 70MW is assigned in the central case.

PB Associates approach to modelling block loads is not made fully explicit in its paper. PB Associates applies a triangular distribution to proposed block loads that is designed to reflect the real-life potential for project delay. Two scenarios are applied. Under the first scenario there is a 50% chance the project will proceed during the year assumed most likely by Western Power, with a 75% chance of the project commencing in the following year if it didn’t proceed in the first year, with the project being initiated in the subsequent year otherwise. Under another scenario there is a 75% chance that the project will commence in the first year as per the best estimate of Western Power.

The explanation of PB Associates is incomplete because PB Associates does not state whether it also takes into account the Western Power probabilities of the project actually proceeding at all, whether it assumes all block loads are commissioned but the only uncertainty is the start date, or whether an alternative set of assumptions is applied.

PB Associates uses Monte Carlo analysis in deriving its demand forecast. PB Associates claims that a key problem with Western Power’s approach is that “block loads cannot be reduced to ‘partial’ demand increases.[4] However, it is unclear how PB Associates overcomes the problem of partial demand increase. If there is a triangular distribution with a 50% probability that a project will be commissioned in year 0 and 75% probability that the project will be commissioned in the subsequent year (if not the first year), then Monte Carlo analysis will still be expected to provide an expected value of roughly 50% of the load in year 0 and 87.5% of the load in year 1. In both years there is the “partial demand increase” that PB Associates criticises Western Power for.

While we believe that PB Associates should make all its modelling assumptions explicit, in practice the treatment of block loads by PB Associates is academic if flaws in the treatment of natural load growth are addressed.

4 Ibid, p.3.

# 3. IMPACT OF INTRODUCING NEW AUGMENTATION OPTION (OPTION 2D)

Western Power has estimated the capital costs associated with a revised Option (Option 2d) that involves construction of a new 132kV line between Eneabba and Geraldton. Western Power advises that this option involves the following steps:

- Stage 1: Construction of a 132 kV line between Eneabba and Geraldton and re-building of the existing Pinjar to Eneabba 132 kV line to a double circuit line with construction by November 2010, with the line supported by additional local generation;
- Stage 2: Re-building of the existing Northern Terminal -Three Springs 132 kV line to a double circuit line with construction by November 2011, with the line supported by additional local generation; and
- Provision of a static var compensator to ensure compliance with voltage requirements.

The net present cost of Option 2d is $373.3 million under a pre-tax nominal discount rate of 10.5%.

The net present cost of Option 2d is approximately $90 million higher than the equivalent net present cost of Option 1 ($283.0) under the same discount rate.

Western Power advises that there may be difficulties with Option 2d that do not arise with Option 1. For example, Western Power advises that simulation studies have highlighted a risk that the system will not be able to accommodate additional wind-farm generation or provide for demand beyond 2015 under the central forecast with Option 2d implemented.

The much higher net present cost of Option 2d implies that Option 1 remains the preferred option.

# 4. ECONOMIC ISSUES ASSOCIATED WITH AN ISLAND GRID OPTION

Western Power has asked us to consider at a high level some of the likely economic costs associated with supplying the proposed 200MW mining development in the Mid-West region from gas fired generation through an islanded system rather than from a coal-fired plant connected to the transmission network.

The following calculations only consider the electricity purchase costs of the mine supplied by the following types of generation:

- A 200MW single unit base load generator connected to the transmission network;
- 250MW of open cycle gas turbine (OCGT) plant under an islanded system; and
- 250MW of combined cycle gas turbine (CCGT) plant under an islanded system.[5]

We have assumed a need for greater redundancy with the OCGT and CCGT plants: with an extra 25% capacity required[6] versus a need to contract for 10% additional capacity for a load connected to the transmission network.

Table 1 estimates the difference in the long run marginal cost of electricity purchase costs using each fuel source based on publicly available information on the marginal cost of generation in Australia and assumptions supplied by Western Power.

**Table 1 Comparison of long run marginal cost of supply ($/MWh)**

| | Unit | Super-critical black coal | OCGT | CCGT |
|---|---|---|---|---|
| Capex | $/kW | 2000 | 900 | 1400 |
| Contingency factor | % | 10% | 25% | 25% |
| Life | Years | 30 | 30 | 30 |
| Variable O&M | $/MWh | 1.57 | 10.29 | 2.86 |
| Fixed O&M | $/MW/year | 32000 | 11000 | 23000 |
| Fuel Cost | $/GJ | 2 | 7 | 7 |
| Efficiency (sent-out) | % | 36% | 34% | 44% |
| Heat rate (sent-out) | GJ/MWh | 9.97 | 10.59 | 8.18 |
| Annualised capex using a pre-tax WACC of 10.5% | $/MW/year | $243,163 | $124,345 | $193,425 |
| Capacity Factor | % | 90% | 90% | 90% |
| LRMC | $/MWh | **$56.42** | **$101.57** | **$87.58** |
| Difference in LRMC with respect to coal | $/MWh | | **$45.16** | **$31.17** |

5 Note that this option may be technically superior for base load operation than the OCGT.

6 This is the difference between 250MW and 200MW.

Data source: ACIL Tasman, *Evaluation of Major Reinforcement of Electricity Network* Table 2, page 36 on New Entrant Assumptions. The values for fuel costs and capacity factor were provided by Western Power. The assumption on gas prices is consistent with the ACIL Tasman views (page 35) that gas prices in the WA can reach up to $7/GJ.

Table 2 estimates the electricity purchase cost savings from supplying the load using coal fired generation through the following steps:

- Taking the difference in LRMC of OCGT/CCGT and the coal alternative;
- Multiplying the difference by the supplied load (MWh); and
- Calculating the present value over a 30-year period assuming alternative discount rates.

Table 2 shows the calculation of electricity purchase cost savings of the coal generation alternative over OCGT/CCGT. As the estimates demonstrate, there is a very significant difference in cost of up to $75 million per year. If these cost savings are calculated over the assumed life of the plant (30 years) and discounted at 7%, the savings are nearly $1 billion compared with OCGT. At a discount rate of 10.5% the savings are around $470 million (CCGT) and $680 million (OCGT).

**Table 2 Calculation of cost savings of coal over OCGT and CCGT**

| Parameter | Relative to OCGT | Relative to CCGT |
|---|---|---|
| Difference in LRMC | $45.16 | $31.17 |
| Annual Energy (GWh) calculated as sum of load MWh over 8,760 hours | 1664 | 1664 |
| Annual cost savings of coal over OCGT ($million/year) | $75.10 | $51.83 |
| **Present value of cost savings over 30-years assuming a discount rate of:** | | |
| 7% | $931.94 | $643.21 |
| 10.5% | $679.48 | $468.97 |
| 12% | $604.96 | $417.53 |

The analysis, while high level may underestimate the difference in electricity purchase costs between OCGT/CCGT and coal for the following reasons:

- The costs are amortised over the assumed life of the plant (30 years) rather than the expected life of the mine, which may be lower;
- The price of gas ($7/GJ) does not take into account delivery costs; and

- In practice there will be a need for a number of units to supply the load using CCGT or OCGT. The analysis assumes that the unit capital cost of developing multiple small units is equivalent to the unit cost of developing a single 250MW unit.[7]

This analysis does not consider the difference in transmission costs or losses between the two options. However, if the difference in present value of electricity purchase costs is at least $470 million, the difference in transmission costs will need to be of equal magnitude (and opposite direction) to render the islanded option economic. It is noted that the estimated difference in electricity purchase costs is far in excess of the net present cost of the capital costs of the preferred transmission augmentation option (Option 1).

7 Note that Acil Tasman assume a single $/kW value for capital costs.