westernpower

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12 December 2011

Mr Lyndon Rowe
Chairman
Economic Regulation Authority
Level 6, 197 St Georges Terrace
Perth WA 6000

Dear Lyndon

SUBMISSION ON AUTHORITY'S DRAFT DECISION FOR NFIT PRE-APPROVAL OF MID WEST ENERGY PROJECT

I am pleased to provide Western Power's submission on the Authority's draft decision of 14 November 2011 on pre-approval of new facilities investment for the proposed Mid West Energy Project.

This formal submission comprises this covering letter and the attached detailed submission documents. Electronic copies are also enclosed, including a version for publication.

Western Power believes it has addressed all the material matters raised in the Authority's draft decision to enable a final determination that approves the application.

In any event, it is very important that the Authority's final decision provides a good indication of the dollar amount that the Authority considers would reasonably satisfy the NFIT. This is necessary to allow Western Power and Government to quantify the financial risks associated with proceeding with the investment and to inform current commercial negotiations for new major connections.

We have worked closely with your secretariat, Government and key stakeholders in the development of this submission and would like to extend our thanks for their contribution, particularly the ERA's attendance and input at our stakeholder sessions in Perth and Geraldton in recent weeks.

To help provide some context around our submission, I would like to provide a high level overview of Western Power's position in relation to the draft determination, together with important contextual information gathered by Western Power through engagement with Government, industry and community stakeholders who we have met with throughout the project development, and in the recent weeks following the draft determination.

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We would like to reaffirm that in February 2011, the Authority said the project satisfied the Regulatory Test, confirming that the project we have proposed is the best option for supplying the electricity needs of the Mid West and that the project maximises benefits to customers. Through the public submission process, the majority of stakeholders agreed.

From a state development perspective, the Mid West Energy project has the potential to enable significant new mining operations, provides certainty of supply to a region which has significant development potential, and provides an opportunity for Western Australia's mid west region to lead the way in wind generation – its potential is world class. The flow-on impacts that the project will bring to the region from a broader economic sense are considered to be substantial by stakeholders. Similarly, the impact of the project not proceeding, or being delayed, would also have substantial impacts for the region in that these opportunities may not be realised.

Western Power firmly believes that the project satisfies NFIT requirements in that the cost of the project is less than our estimates of the electricity market benefits. The flow-on economic benefits to the Mid West could be substantially larger.

It is significant that Western Power's view is supported by all of the published public submissions to date, and largely by the Authority's own consultants. In particular, we note the statement from the your consultant Marsden Jacob & Associates which supports the project passing NFIT –

> *"... If all of the above adjustments were required, the total impact would be a reduction of $57 million in benefits. Even with this adjustment, the total benefits ($419 million) would still outweigh the cost of the new facility ($383 million). Therefore the resolution of these issues is unlikely to result in the project failing NFIT ..." (report pp 17-18)."*

The Authority has questioned this evaluation in its draft determination, suggesting that the benefits are not certain enough and pose an unreasonable risk for existing customers, in terms of price impacts.

Whilst acknowledging the serious nature of price impacts, Western Power takes a different view in that we believe there is sufficient certainty in the benefits which customers will receive as a result of this project - meaning that the benefits outweigh the cost.

The ERA has commented publicly that electricity prices for existing customers could be significantly higher should this project progress. Our modelling indicates that in the short term the potential network price impact for contestable customers (those using 50,000 units of electricity or more per year) would be less than 2% on average, which equates to a retail electricity price impact of less than 1% <u>on average</u>. Our longer term modelling, in fact, shows us that customers will be better off due to forecast additional revenues from new mining loads and connection of new sources of generation, together providing downward pressure on electricity prices. Further, many of these very businesses are likely to benefit from the new commercial opportunities a project like this brings to the region. Western Power's view is that consideration of economic benefits needs a long term view.

The ERA has also suggested that Western Power may choose to progress with this project in the absence of NFIT approval – and that we could establish a speculative investment fund. The purpose of this would be to enable a financial return on the investment to commence at some future point in time when the need for the project is 100% certain. It is important to recognise that by treating this project as speculative investment Western Power would essentially receive no guarantee of a commercial return. The financial risk of treating such a large project as speculative investment is not acceptable to Western Power or its owner.

Importantly, MWEP Stage 1 will also offer more reliable connections to customers. It strengthens the northern section network, effectively bringing the 330kV source point to Three Springs thereby allowing more power to be transferred to Geraldton. This will resolve existing firm capacity constraints on the existing network between Neerabup to Three Springs. Our stakeholders have told us that the current availability of new connections on a curtailable basis only is limiting development in the region. As such, there are reliability benefits in progressing with MWEP as planned.

MWEP Stage 1 facilitates the connection of 155 MW of new wind turbine generation without any further addition of block loads. More can then sustainably be added to the network if magnetite iron ore mines (which are 24/7 and often non-interruptible operations) connect and operate as planned.

There are a number of non-network solutions that Western Power will consider if the MWEP project is delayed. This includes the provision of Network Control Services which essentially involves Western Power entering into contracts with new generators to provide additional local capacity and/or with major customers who are prepared to use less power under peak load conditions. These are credible non-network solutions to ensure reliability of supply to Geraldton as MWEP is being developed. However, they are not a replacement for the need for the project and would increase overall costs as it would likely only delay the costs of the MWEP, not avoid them.

Any continuing delay to MWEP will increase the risk to the network. This may eventually result in the need to implement a less efficient network solution in order to continue supplying Geraldton reliably.

If pre-NFIT approval is not achieved:

- There is a risk of MWEP Stage 1 not going ahead - or being delayed;
- There is the potential for increased costs to the project, associated with the favourable transmission construction market conditions existing at present;
- Less efficient piecemeal reinforcement may be required - which would be at odds with the Regulatory Test approval;
- There will be on-going constraints for customers and projects (including wind generation) in the region wanting to connect to network;
- Those customers who require uncurtailable supplies (relevant for many mining operations and industrial customers) will need to obtain site back up generation at additional cost; and

- To progress with the project Western Power would require underwriting from major customers or Government

In our recent public forums in Geraldton and the Mid West there was a clear preference for Western Power to build for the long term to support future growth in the region. We believe that is what this project delivers – and that now is the right time. Similarly, our public forums in Perth and Geraldton sent a clear message that stakeholders support the project going ahead, to bring with it the significant benefits it will offer the region. Moreover, in the lead up to this draft NFIT determination, a number of parties provided submissions to the ERA. All of these submissions were supportive of the proposal.

I would like to thank you for the opportunity to make this submission, and for the engagement opportunities we have had with the ERA secretariat.

I look forward to receiving the Authority's final determination.

Yours sincerely,

[redacted]

DOUG ABERLE
MANAGING DIRECTOR

Submission to the Economic Regulation Authority

WESTERN POWER'S RESPONSE TO DRAFT DECISION ON NEW FACILITIES INVESTMENT TEST PRE-APPROVAL FOR MID WEST ENERGY PROJECT (SOUTHERN SECTION)

DATE: 12 December 2011

DOCUMENT PREPARED BY:

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safe reliable efficient

Contents

Glossary

Abbreviation / Acronym	Definition
the Code	Electricity Networks Access Code 2004
DTF	Department of Treasury and Finance
ENB	Eneabba
ENT	Eneabba Terminal
ERA	Economic Regulatory Authority
ETAC	Electricity Transfer Access Contract
EUC	Early Undertakings Contract
GGV	Golden Grove
IDC	Interest During Construction
KML	Karara Mining Limited
MOR	Moora
MWEP	Mid West Energy Project
NBT	Neerabup
NFIT	New Facilities Investment Test
NPC	Net Present Cost
PNJ	Pinjar
SWIS	South West Interconnected System
SWIN	South West Interconnected Network
TST	Three Springs Terminal
WPN	Western Power Network

1 Executive Summary

As requested in the Authority's Draft Decision, Western Power has reviewed the following key aspects of its NFIT pre-approval application for the Mid West Energy Project (MWEP):

- Updated cost estimates for the project;
- Valuation of incremental revenue; and
- Net benefits estimates.

Western Power addresses each of these matters in this submission, together with relevant new information and commentary on a number of related aspects of the decision.

Western Power has considered the views of the Authority's technical consultant and responds to the areas of difference, noting that the decision considers that the project is largely efficient (96%). We request that the Authority does not simply substitute Western Power's views of the technical design requirements with the views of its consultants, particularly where these view are immaterial to the total cost of the project. This could amount to differing views of technical experts rather than be representative of inefficient costs. Therefore, we contend that the Authority must be satisfied that its consultant is right and our design standards are wrong to avoid any unintended negative consequences for incentives for efficiency, good industry practice and appropriate accountability.

In addition, the Authority has indicated that the important principle that all other customers should not be worse off as a result of new investment needs to be demonstrated to ensure that the sharing of risk and price impacts is appropriate.

Western Power has assessed the impact on existing customers using the Discounted Weighted Average Tariff (DWAT) approach. This approach allows the assessment of the price impact to other customers from a particular project. Two scenarios were examined using the AA3 cost-of-service model for determining tariffs:

1. Without the MWEP (Southern Section); and
2. With the MWEP (Southern Section).

The analysis demonstrates that although an assessment of network tariffs alone suggests prices would rise, the benefits to be realized by customers as a result of the project are greater than the additional cost. These benefits include reductions in generation costs which should flow through to end use prices. The likely benefit-cost ratio for existing customers is 1.7.

This supports Western Power's assessment that the MWEP (Southern Section) passes NFIT and that when delivered as planned, the full amount of $378.9M should be added to our capital base.

Importantly, Western Power reiterates that it will not proceed with this investment until commercial arrangements are in place with at least one foundation major load (mining customer), including security over the associated future revenue stream(s).

Western Power has not sought a capital contribution from any customers for this project because we have assessed that the project passes NFIT. It is not appropriate for Western Power to require a capital contribution when this is the case.

To the extent that the ERA determines a different outcome, for example that a capital contribution is required, then we request the ERA to determine the amount also. This is because we have not been able to determine an appropriate amount other than zero and nor have the ERA been able to be definitive in any amount to date.

Further, in the circumstances that the ERA concludes that a capital contribution is required and we are unable to secure one, the project will not proceed. This is because it is not commercial or appropriate to use shareholder funds to fund investment where the likelihood of a return on that investment is indeterminate.

2 Introduction

2.1 Authority's Draft Decision

The Authority's draft determination is that it cannot give pre-approval at this stage for the total proposed expenditure of $383.4M as requested by Western Power.

In particular, the Authority has requested that Western Power provide further information:

16. To address its concerns, the Authority seeks from Western Power:

- updated estimates for the value of the proposed new network investments – to remove the amounts identified as not consistent with the requirements of the efficiency test;

- a revised valuation of incremental revenue – utilising existing transmission tariffs, and incorporating only those incremental block loads that can be demonstrated to be reasonably assured; and

- a re-working of the net benefits estimates – to provide additional support for the counterfactual scenario chosen for the 'with' and 'without' cases, and to further examine the sensitivity of the outcomes to assumptions which support the entry of new wind generation.

In addition, the Authority has expressed concerns about the sharing of financial risk and the price exposure of existing customers in particular.

Western Power addresses each of these matters in this submission, together with commentary on a number of related aspects of the decision.

2.2 Overview of Submission

The submission is structured as follows:

- This Section 2 provides Western Power's views on a number of key aspects of the Authority's decision;

- Section 3 provides updated project estimates and supporting commentary on the Authority's judgements about the project efficiency;

- Section 4 addresses the questions on incremental revenue, including the appropriate parameters used in the calculations;

- Section 5 presents revised net benefits estimates, with supporting information from ACIL Tasman contained in Appendix 2;

- Section 6 presents Western Power's assessment of the impact on existing customers; and

- Section 7 provides a summary of Western Power's conclusions and reasoning why it considers that the project satisfies the NFIT.

2.3 Comments on the Authority's Efficiency/Technical Review

The Authority found that for the assets constructed by WP:

- the choice of project was efficient
- the design standards are reasonable and consistent with good industry practice
- the delivery plan should lead to efficient cost outcomes.

However, the Authority has had its own technical consultant review the design standards and the technical consultant considers three areas of the design for the assets constructed by Western Power are inefficient, totalling $4.57M or just over 1 per cent of total cost of the project. Western Power does not agree with the Authority's determination on these technical matters and has provided a detailed response to each item in Section 3.

For the assets constructed by Karara, the Authority considers that the design for the Eneabba-Three Springs line was not optimal as it used a previous design standard of Western Power's that has subsequently been updated. Although noting that construction by Karara has commenced, the Authority considers that the NFIT value for this line should reflect Western Power's current design standards even though this standard did not exist when construction started. We contend that the Authority should base its assessment on the information that existed at the time the decisions were made, and not apply the benefit of hindsight. It should also be noted that the technical consultant disagreed with one additional element of the design which has resulted in a further $175,000 (less than 0.0004%) being considered inefficient.

Although, we have provided information in this submission to contest the issues where the technical consultant Geoff Brown & Associates (GBA) has disagreed with Western Power, we consider that the approach adopted by the Authority in its assessment may lead to inefficient investment outcomes and the potential for increased costs to customers.

Western Power contends that where there is a difference of opinion of technical experts (in this case Western Power's designers and the ERA's technical consultant) that any variation that results from this difference of opinion ought to be subject to a reasonableness test. Only where the difference is material should this be considered to be more than a difference of expert opinion and might rightly be investigated further to ensure that there is no evidence of inefficiency. To do otherwise would require Western Power (and customers) to incur unnecessary additional time, delays and costs in evaluating or altering designs which ultimately Western Power (not the Authority or its consultant) must be accountable for.

Therefore, we contend that the Authority must be satisfied that its consultant is right and our design standards are wrong to avoid any unintended negative consequences for incentives for efficiency, good industry practice and appropriate accountability.

2.4 Comments on the Marsden Jacobs & Associates Report to the Authority

Western Power notes and is encouraged by the advice provided by economic consultants Marsden Jacobs & Associates (MJA) to the Authority which strongly supports Western Power's claim that this project does indeed satisfy the NFIT.

MJA supported Western Power's benefits assessment methodology but considered that a number of adjustments to Western Power's analysis would be prudent and, in particular:

- Suggested the use of published prices instead of forecast actual prices in the incremental revenue assessment;
- Queried the use of Western Power's 2004 network valuation as part of the nodal price calculations;

- Suggested the timeframe for the incremental revenue estimate should be reduced from 40 years to 20 years;
- Recommended that net benefits should be based on the medium growth scenario rather than the high growth scenario.

MJA re-assessed Western Power's analysis based on their suggested modified parameters and concluded:

> "…If all of the above adjustments were required, the total impact would be a reduction of $57 million in benefits. Even with this adjustment, the total benefits ($419 million) would still outweigh the cost of the new facility ($383 million). Therefore the resolution of these issues is unlikely to result in the project failing NFIT…"[1]

It is extremely surprising and difficult for Western Power and other government and industry stakeholders to understand why the Authority has not accepted the advice provided by its own specialist consultant.

2.5 Comments on Customer Risk

Western Power understands the Authority's concerns about the potential demand-side risk that existing customers could theoretically be exposed to. Demand side risk is an unavoidable element of any augmentation for new investment. The fact that the augmentation or new investment does not exist suggests that the expected use of the that investment is speculative. It is usual business practice for WP to make assumptions about future load requirements. WP considers its assumption in relation to future demand is in line with good industry practice. Therefore, the focus here should not be on whether the demand exists but rather the process and approach to determining whether it will exist.

Further, demand-side risk is also managed via commercial arrangements in accordance with the Contributions Policy. This includes, among other things, bank guarantees that secure the anticipated incremental revenue from new customers. Importantly, Western Power will not proceed with this investment until commercial arrangements are in place with at least one foundation major load (mining customer), including security over the associated future revenue stream(s).

2.6 Comments on "Speculative Investment"

Western Power notes the Authority's view that this project could proceed as "speculative investment" as defined in the Code, whereby Western Power takes on the commercial risk of the full investment not satisfying the NFIT, rather than customers carrying this risk.

However, such an approach to a planned major investment increases the commercial risk to Western Power and this risk has not been incorporated in the return on investment to date.

In the absence of providing a higher return on any amounts included as speculative investment, it is not commercial or appropriate for WP to use shareholder funds to invest in that project.

Western Power will continue to use the speculative investment provisions for investment that is disallowed from inclusion in the capital base <u>after</u> the investment is undertaken.

[1] Ibid. pp. 17-18.

2.7 Reliability benefits

Importantly, MWEP Stage 1 will also offer more reliable connections to customers. It strengthens the northern section network, effectively bringing the 330kV source point to Three Springs thereby allowing more power to be transferred to Geraldton and offers lower cost options for reinforcing the supply to Geraldton and deferring more expensive augmentations. This network deferral benefit has been quantified and included in the net market benefits for MWEP stage 1.

Currently any block load above 3 MVA wishing to connect north of Neerabup must agree to be curtailable to ensure reliability of supply to other customers. The MWEP stage 1 will allow this restriction to be lifted for Customers connecting between Neerabup and Three Springs. Our stakeholders have told us that the current availability of new connections on a curtailable basis only, is limiting development in the region. As such, there are additional reliability benefits in progressing with MWEP as planned.

2.8 Nature of the Authority's Final Determination

It is very important to Western Power that, in the event that the Authority is unable to conclude that the full project amount satisfies the NFIT, the Authority clearly declares in its final decision the amount that it does consider to satisfy the test.

Western Power has not sought a capital contribution from any customers for this project because we have assessed that the project passes NFIT. It is not appropriate for Western Power to require a capital contribution when this is the case.

To the extent that the ERA determines a different outcome, for example that a capital contribution is required, then we request the ERA to determine the amount also. This is because we have not been able to determine an appropriate amount other than zero and nor have the ERA been able to be definitive in any amount to date.

This information would be essential to enable Western Power to fully assess the level of any residual commercial risk in order to:

- inform the Western Power Board's decision on whether to proceed with the project (or otherwise);
- acquire capital funding and formal approval from Government; and
- progress commercial negotiations with parties in the region seeking connection to the network[2].

A simple "not approved" final decision would effectively stall this project indefinitely and further frustrate the processing of new connection applications for which this major investment is contingent.

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[2] For the purposes of finalizing commercial arrangements, it is necessary to determine an NFIT value for the project. This is in part due to section 5.14 (a) of the Access Code, which states:

> "…Subject to section 5.17A and a *headworks scheme*, a *contributions policy*:
>
> (a) Must not require a *user* to make a *contribution* in respect of any part of *new facilities investment* which meets the *new facilities investment test*…"[2]

This section establishes a clear link between NFIT and the Contributions Policy in which the contribution payment is an outcome of applying NFIT.

3 Project Efficiency & Updated Estimates

3.1 Overview

Western Power has considered ERA's draft determination on project efficiency and design issues. Western Power does not agree with the determination and is in the opinion that the project is efficient. However, Western Power agrees with the ERA that the amount to be added to our asset base would include any depreciation of assets that have been in use for a period of time.

Western Power's detailed response to each item and other queries raised by the ERA is covered in the remainder of this section.

3.2 ERA draft determination

The ERA had its own technical consultant review the design standards and the technical consultant has disagreed with selected areas of the design totalling $16.7M or just over 4 per cent of the total cost of the project. The areas of disagreement that result in the cost difference are provided in the table below.

Table 1: Efficiency of technical areas raised by ERA

Project efficiency and design issues raised by ERA	Paragraph	ERA suggested reduction to NFIT $M
Design of the conductor to 85 C instead of 75 C	66	0.5
Undergrounding portion of the Pinjar to Cataby 132 kV line rather than an overhead option	67	3
Transformer sizing at Three Springs Terminal (490 MVA versus 250 MVA)	68	1.07
KML design of the Eneabba Terminal to Three Spring Terminal line (non-optimised span)	76	5.175
Depreciation of assets to be purchased from KML Three Springs Terminal - $2.69M Eneabba Terminal – Three Spring Terminal line - $3.73M Eneabba Substation – Eneabba Terminal line - $0.51M	83	6.93
	Total	16.675

3.3 Assets Constructed by Western Power

3.3.1 Design of line conductor (75C or 85C)

ISSUE RAISED BY THE AUTHORITY

Paragraph 66:

"… *Western Power, New Facilities Investment Test Application, page 36. that Western Power has designed the line for maximum conductor temperature of 85 C, rather than the 75 C maximum temperature used elsewhere on its 330 kV network – in order to increase the thermal power transfer capacity of each 330 kV circuit from 1,000 MVA to 1,200 MVA. This has required Economic Regulation Authority Draft Determination on the New Facilities Investment Test Application[15] for the Mid West Energy Project (Southern Section) the use of taller towers to increase ground clearance at an additional cost of $0.5 million. While this additional cost is relatively modest, the Authority's technical adviser does not consider the additional capacity provided is needed, even under a high load growth scenario. GBA also notes that an equivalent expansion in capacity could be achieved later – at modest cost compared to 'the cost of a new line or the incremental cost of building the line on 500 kV* *towers' – with the addition of reactive power compensation*[13] *On this basis, the Authority considers that the NFIT cost should be reduced by $0.5 million."*

WESTERN POWER'S RESPONSE

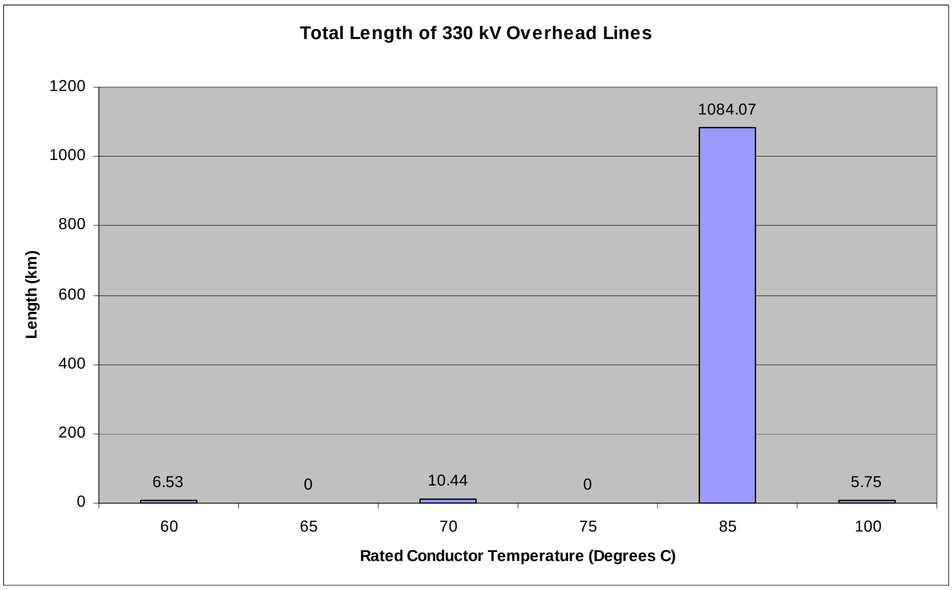
- The Geoff Brown & Associates (GBA) Technical Review Report (Draft 2 – November 2011), released by ERA, has determined that the cost different between the line designed to maximum temperature of 85° C and the lower 75° C is immaterial. In GBA's report it quotes in reference to the conductor design temperature "This amounts to less than 0.2% of the overall project cost, which is hardly material in the context of the total project cost". Western Power agrees with GBA.

- Paragraph 66 of the Draft Determination incorrectly state that 75° C is used elsewhere on our 330 kV network. More than 98% of our existing 330 kV lines are designed to 85° C (please see Figure 1).

- Given that most of our lines are already designed to 85° C, there are advantages of a standard approach in relation to simplifying operations, maintenance and risk management.

- Western Power considers the higher temperature conductor appropriate because it provides significant extra capacity, should the additional demand eventuate, for a very small incremental cost. Retrofitting the line at a later stage to increase capacity is not possible. Also, over such a long line, the alternative of installing reactive compensation equipment to increase transfer capacity will be higher than the additional cost of designing the line to 85° C.

Figure 1: Length of Western Power 330 kV Overhead lines



3.3.2 Undergrounding of the Pinjar to Cataby 132 kV line

ISSUE RAISED BY THE AUTHORITY

Paragraph 67:

"The Authority's technical adviser also noted that Western Power appears to have taken a conservative approach to risk management and has included provision in the design to mitigate risks that GBA considers many service providers seeking to minimise costs would consider tolerable. GBA notes that in particular Western Power has provided for the undergrounding of a section of the double circuit 132 kV Pinjar-Cataby line where it passes under the new 330 kV circuit, at an estimated cost of $3 million in order to avoid a double circuit outage in the event of a conductor failure at that particular location. GBA considers the risk to be small and could potentially be mitigated by implementing an enhanced maintenance regime for the span concerned. It could also have been addressed at a much lower cost by diverting the existing line on to shorter towers. The Authority requires that Western Power re-consider this component."

WESTERN POWER'S RESPONSE

- Western Power investigated 3 options during the scoping and planning phases of the project. These options together with their direct construction cost are:
  - Option 1: Overhead crossing 330 kV under existing 132 kV ($3.0M)
  - Option 2: Overhead crossing by lowering 132 kV under 330 kV ($2.9M)
  - Option 3: Underground crossing 132 kV under 330 kV ($3.1M)

  Option 2 is the option suggested by GBA to divert the existing line to shorter towers.

- Refer to Appendix 2 of this document for a detailed layout of each of the design considerations.

- The cost difference between the options is very small but benefits of Option 3 such as constructability and minimum operation risk across the whole life-cycle outweigh this cost difference. Therefore, Option 3, the undergrounding option is the most efficient option.

- Option 3 minimizes outages of existing 132 kV circuits during construction. The outages for Option 1 and 2 are much longer. In addition, there is a greater risk of double outage of both existing 132 kV circuits being required to enable construction to be undertaken. A double outage has a high potential to lead to an event which would interrupt supplies to customers. Using a cost based on value of customer reliability (VCR) of $55.52[3] per kWh shows that an outage of 10 minutes would cover the cost difference of implementing Option 3.

- Moreover, Option 3 is the only option that will not cause any double circuit outage in event of a conductor failure at the crossing. The risk of conductor failure cannot be fully mitigated.

- A double circuit outage of the 132 kV line due to broken conductor of the 330 kV will blackout all the 132 kV substations North of Pinjar to Eneabba. This includes the Cataby, Regans, Emu Downs and Eneabba substations.

- Considering the 2010 peak the load of these substations is 21 MW4 (Cataby (1.51 MW), Regans (13.2 MW) and Eneabba (6.3 MW)). A four hours disruption during

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[3] *DM#8674440 – Revenue model for ERA 30Sept2011 (AA3 Submission) – VCR $ real as at 30 June 2012*
[4] *Summer 2011 Transmission Loads and Circuits Report*

this peak period will incur a cost to customers of $4.7M[5] based on the VCR. The cost of a single broken conductor event is higher than the cost differential of implementing the underground option. The cost of this risk will be higher in the future as the load supplied by these substations increases.

– Western Power believes that the whole of the $3.1M costs of this crossing passes NFIT.

3.3.3 Transformer size at Three Springs Terminal

ISSUE RAISED BY THE AUTHORITY

Paragraph 68:

"In the case of the Three Springs Terminal, the Authority's technical adviser considers the overall design to be reasonable. However, GBA's assessment is that a 250 MVA transformer is all that is required at this stage, rather than the 490 MVA unit proposed by Western Power. Additional transformer capacity could then be added incrementally at a later stage if required – two 250 MVA transformers could provide sufficient capacity to meet the central forecast through until 2030, while a third transformer would only be required before that time if load growth approaches the high forecast. Installation of a smaller transformer would reduce the estimated cost by $1.07 million. On this basis, the Authority requires Western Power to show cause why it could not adopt the small transformer option"

WESTERN POWER'S RESPONSE

– ERA agrees the high load forecast most likely

  o The transformer has been sized based on the high forecast scenario (see Figure 2). The ERA considered in its assessment of the Regulatory Test application that the high forecast scenario represents a more likely estimate of future demand growth than either the central or the low forecasts.

– 490 MVA transformer is the most efficient, lowest cost to meet the high forecast load.

  o Under the high forecast scenario the MWEP Southern Section would require upgrade to a double circuit 330 kV line by 2015/16 as reported in the approved Regulatory Test for the project. When this occurs, the 330/132 kV transformer will be the network point that connects Three Springs and the northern section 132 kV network to the SWIS (See Figure 3). A second transformer will be required to maintain an N-1 connection.

  o The high forecast scenario shows that the load at Geraldton (northern section) will grow from around 200 MW in 2017 to 250 MW in 2020 and 290 MW in 2030. This coupled with the 132 kV load at Three Springs and the reactive power flow means that total apparent load on the 132 kV network supplied by the transformers will be higher or very close to 250 MVA from 2017.

  o With a lower rated 250 MVA transformer, the third unit will be required as early as 2017. Analyses have shown that a reactive compensation of 50 MVar for the 330 kV lines are required to be connected at the tertiary

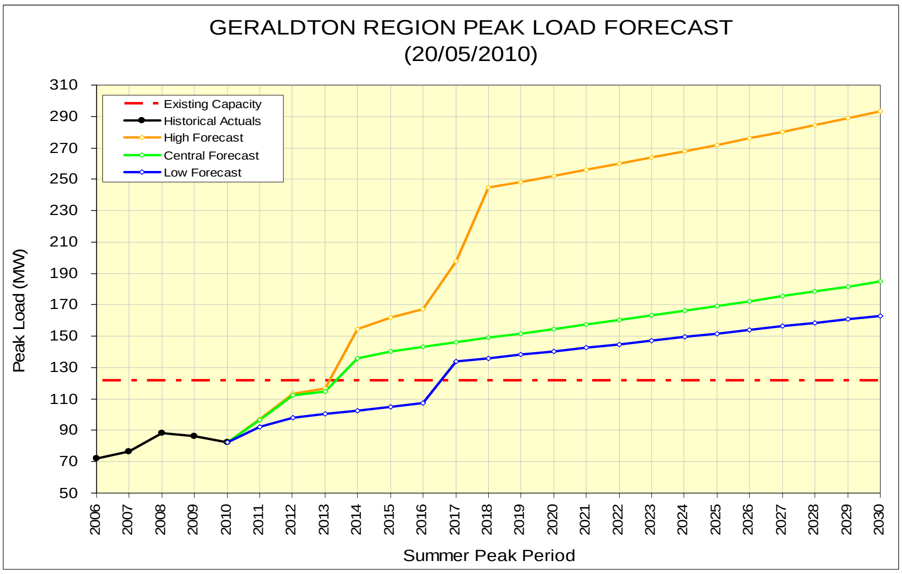
[5] *Cost to customers based on VCR is obtained by: 21MW * 4 hrs * VCR = $4.6M*

winding of the transformers. This reduces the capacity of the transformer to supply load. The 490 MVA transformers provide sufficient capacity to account for all eventual load scenarios.

- o A financial analysis conducted shows that the option of having two units of 490 MVA transformer at Three Springs Terminal has a lower NPC compared to the option of having three units of 250 MVA transformers, with the third unit added in 2017. The saving using the proposed 490 MVA transformers is $8.6M[6].

- o If the third unit of 250 MVA is not added, then an alternative supply path to the Geraldton area via 330 kV voltage level will be required to supply the Geraldton load in 2017. This will significantly bring forward the need to construct a 330 kV terminal substation near Geraldton. (See Figure 4)

Figure 2: Geraldton region peak load forecast



– In addition the use of the 490MVA provides superior flexibility for further growth because of the following;

- o The larger transformers also allow the supply to Geraldton (northern section) to be developed in stages, and defer the need for a 330 kV terminal substation at Geraldton for some years. Any proposed 330 kV lines to replace the existing 132 kV lines to Geraldton can be initially operated at 132 kV. A sensitivity analyses have shown that deferral of the terminal substation by one year (from 2016 to 2017) reduces the NPC by $1.9M[7]. The NPC to establish the terminal substation in 2016 is $32.4M and in 2017 is $30.5M (see Figure 5 below). The NPC will be much lower if the terminal substation can be further deferred through the use of the 490 MVA transformers until the transfer limit of 132 kV voltage level is reached. Based on the high forecast scenario in Figure 2, it is likely that the deferment of the terminal substation in the north can be in excess of five years.

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[6] *DM#8473229 – Mid West Energy Project (Southern Section) Planning Considerations July 2011*

[7] *DM#8493616 – Investment Evaluation Model for Geraldton Terminal*

- It is not Western Power assumption to transmit 400 MVA at 132 kV to the Geraldton area as suggested by GBA. Western Power agrees that should such demand materialized in the north (i.e. Geraldton area) then a 330 kV transmission level is required. Western Power's intention is to defer the need to establish the 330 kV terminal substation in the north with the 490 MVA transformers until such time as the demand requires this voltage level. As explained this deferment (up to 5 years in high case) can be achieved with the 490MVA transformer sizing.

– In summary, the net cost benefit of using the 330/132 kV 490 MVA transformers at Three Springs Terminal outweighs the initial cost reduction of using a smaller transformer. Western Power considers that the initial installation of the 490 MVA transformer is the most efficient option for supplying the future expected loads in the region. Installation of a lower capacity transformer is likely to expose customers to higher costs over time and is therefore not a prudent or efficient investment.

Figure 3: Network with the 490 MVA transformers

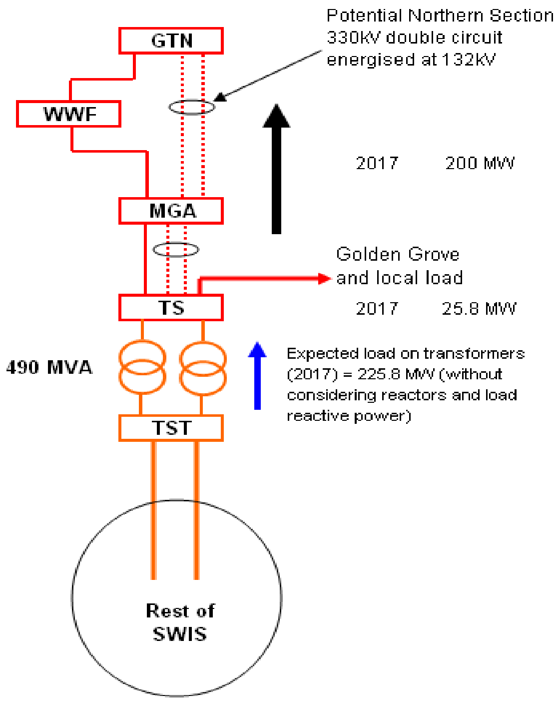
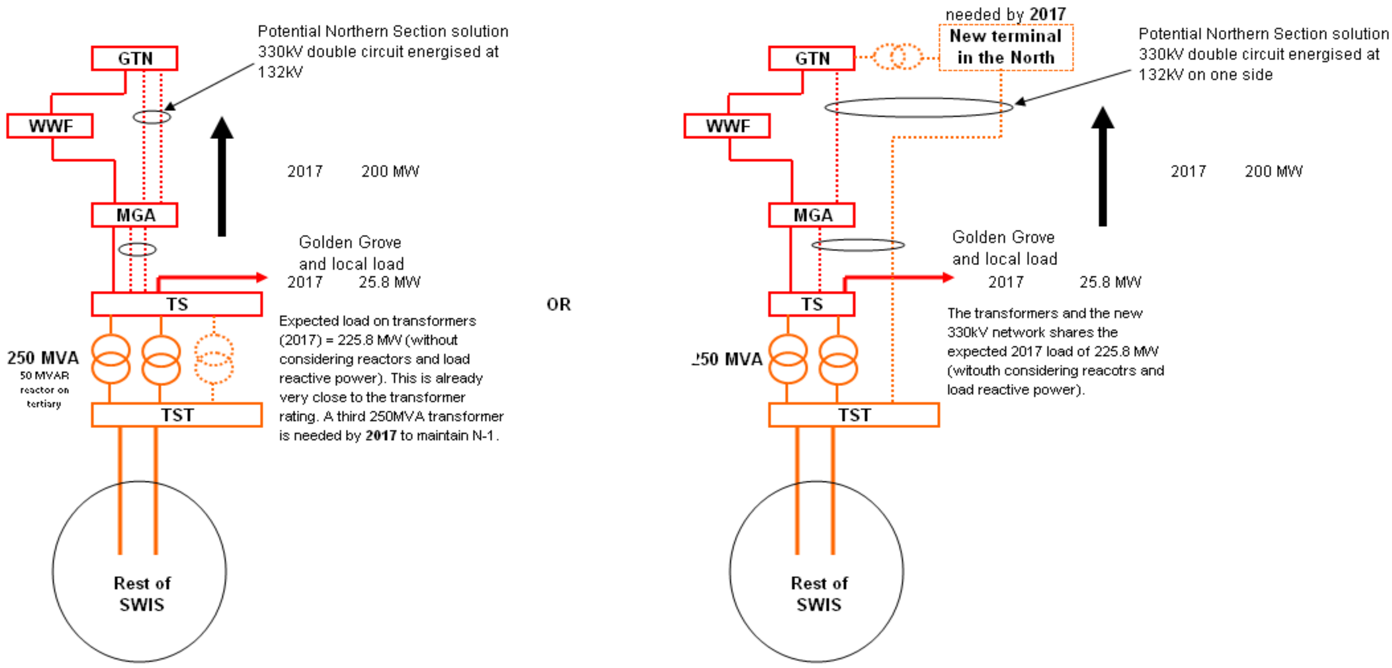


Figure 4: Network with the 250 MVA transformers



3.3.4 Project cost to date

ISSUE RAISED BY THE AUTHORITY

Paragraph 70:

"The proposed expenditure includes $21.3 million for project development costs incurred to date. From the information provided by Western Power it is not clear whether the costs relating to the planning for the original proposed Northern Line and the costs of preparing the 2007 regulatory and NFIT applications in relation to that proposal have been excluded from this amount. Only those costs which relate to planning for the current proposal should be included. Western Power will need to provide further evidence that this is the case before the Authority can approve the total amount. "

WESTERN POWER'S RESPONSE

– Western Power would like to clarify that the development cost to date of $21.3M provided to ERA in our letter dated 13th Sept 2011 (ref DM# 8609615) is the actual cost incurred to date on the MWEP Southern Section project. The cost to date includes the cost incurred for project planning and approvals, project estimates, project management, design and strategic purchase of plant and equipment for the MWEP Southern Section only.

– This $21.3M of cost to date is made up of two parts. One is the cost incurred to date by Western Power on the MWEP Southern Section work. The second part is the cost incurred for purchase of primary plant for the construction of Three Springs Terminal (TST). The breakdown of the development cost to date is provided in Table 2 below.

– The cost to date does not include any cost for work related to the Northern Section (Eneabba to Moonyoonooka), with Western Power having separated the relevant cost elements of the Northern and Southern sections of the previous combined project, prior to proceeding with the current MWEP Southern Section submissions. Western Power reconfirms that a further $9.1M is allocated to a MWEP (Northern

Section) potential future project and is excluded from this MWEP Southern Section project, as previously communicated to ERA in our letter dated 13th Sept 2011 (ref DM# 8609615).

- As the development cost to date are actual cost already incurred, the movement in exchange rates and commodity prices have no relevance to the cost.

Table 2: MWEP Southern Section development cost to date (nominal value)

Cost items	$M	$M
Western Power MWEP Southern Section Work		
Project planning and approvals, project estimates and project management	5.34*	
Project Design (inc testing of lines)	2.47	
Purchase of foundation materials	1.73	
Early works in substations	1.09	
Sub-total		**10.7**
KML Payments		
Three Springs Terminal (to be refunded subject to NFIT)	10.6	
Sub-total		**10.6**
Total development cost to date		**21.3**

** note that this cost of $5.34M is not related to the estimated project planning cost of $5.72M presented in Table 4.1 of Western Power's Planning Phase Cost Estimate Report[8]. This cost of $5.34M includes a component of planning cost incurred to date but is not solely attributed to planning. It also includes the Project Management cost incurred to date.*

3.4 Assets constructed by Karara

3.4.1 On the span of the Eneabba Terminal to Three Springs Terminal line

ISSUE RAISED BY THE AUTHORITY

Paragraph 76:

"In the case of the Eneabba Terminal to Three Springs Terminal line, the NFIT cost is based on a previous design that is not optimal.[15] GBA notes that, had construction been delayed to coincide with the construction of the Pinjar-Eneabba line, the cost would have been reduced by an estimated $5 million because the line would have been built to an optimised design on 600 metre spans. The original design has been retained for the NFIT by Western Power because KML has already commenced construction based on the old design. In addition, the design of the line is for 85 C, rather than 75 C, and is considered by GBA to be unnecessary and estimated to add $175,000 to the cost. The Authority considers that these two additional costs are not efficient, and that the NFIT amount should be reduced accordingly."

WESTERN POWER'S RESPONSE

- KML undertook the Eneabba Terminal (ENT) to Three Springs Terminal (TST) line design and construction to ensure a temporary supply was available for mine start-up. KML was not required by the Authority to undertake the Regulatory Test.

[8] *Table 4.1 DM#7482729v6D*

- KML has followed appropriate design standards available at the time committed decisions were made to design the ENT-TST line. The design employed by KML was also consistent with the prevailing Western Power design standard intended for the 330 kV North Country transmission project at the time and this standard should be considered as efficient in determining the purchase price and NFIT value.
- Western Power has since revised its line standard. At the point of KML designing the line, the revised (optimized) Western Power design standard for the current 330 kV MWEP Southern Section line design based on longer span lengths was not available.
- It was appropriate to use the standard that existed at the time to not do so considerably increase the risk faced by WP as any investment would be subject to an assessment of hindsight which is impossible to meet.
- Therefore, the design of the Eneabba Terminal to Three Springs Terminal line should be considered an efficient design.

3.4.2 Timing of addition of investment to the regulatory asset base

ISSUE RAISED BY THE AUTHORITY

Paragraph 78:

“Costs relating to the assets constructed by Karara should only be included in Western Power’s capital base on completion of the MWEP, which is scheduled for March 2014. Prior to this point, KML is the only party to benefit from the use of the interim assets. For example, the Three Springs transformer is unlikely to be required until the proposed augmentation is commissioned. “

WESTERN POWER'S RESPONSE

- Western Power confirms that assets constructed by KML will only be included in its capital base on completion of MWEP.

3.4.3 Depreciation of the KML assets

ISSUE RAISED BY THE AUTHORITY

Paragraph 83:

“A significant element of the total proposed augmentation is initially being constructed by KML and will subsequently be sold to Western Power. Consideration of the amount to be added to Western Power’s asset base would include any depreciation of assets that have been in use for a period of time (for the benefit of KML).”

WESTERN POWER'S RESPONSE

- Western Power agrees with ERA that the amount to be added to Western Power’s asset base would include any depreciation of assets that have been in use for a period of time.
- However, Western Power does not agree with the depreciation suggested by GBA of $6.93M.
- Western Power’s access arrangement is based on expected economic lives of 60 years for transmission lines and 50 years for transmission substations.

- Based on this expected life, the estimated depreciation from Qtr 1 2012 to the expected date of purchase of Qtr 1 2014 is presented in Table 3 below.

- The amount of $4.5M is the calculation of the amount that should be considered as the depreciation in the NFIT.

Table 3:Calculation of Depreciation using Western Power's Method

Item	MWEP Estimate ($M)	ENT-TST Estimate ($M)	IDC ($M)	Dep. ($M)	NFIT Cost* ($M)
Item 1 – PNJ-ENB Line and associated works	$255.8				$255.8
Item 2- TST	$37.9		$3.3	-$1.6	$39.6
Item 3 – ENB – TST Line works	$10.8		$1.0	-$0.4	$11.4
Item 4 – ENT – TST Line works		$68.7	$5.9	-$2.5	$72.1
Subtotal NFIT Values	**$304.5**	**$68.7**	**$10.2**	**-$4.5**	**378.9**
Connection assets	$1.8				
Total Estimate Values	**$306.3**	**$68.7**	**$10.2**	**-$4.5**	

** based on Table 5 in Western Power Pre-NFIT Application submission with inclusion of depreciation. The cost is based on July 2010 value. Note that the actual depreciation cost depends on the date of actual transaction. The above estimated cost is based on estimated depreciation from Qtr 1 2012 to date of purchase of Qtr 1 2014.*

3.4.4 Review of IDC (Interest during construction)

ISSUE RAISED BY THE AUTHORITY

Paragraph 82:

"It is reasonable therefore to include IDC costs incurred prior to commissioning of the line by KML. However, IDC should not be included for the period of interim use of the assets by KML, subsequent to completion, but prior to the commissioning by Western Power of the MWEP. Accordingly, Western Power should revisit the estimates of IDC. "

WESTERN POWER'S RESPONSE

- The IDC costs in Table 14, 15 and 16 of Western Power's Pre-NFIT Application submission were calculated for the construction period of the projects only.

- The construction period considered is the proposed period of construction for the individual projects should those projects be developed by Western Power based on its requirement and on an efficient delivery prospective.

- The estimate of the cost is therefore consistent with the approach suggested by GBA to account for the IDC.

3.5 Summary

Western Power considers the actual and estimated costs are efficient. Western Power accepts that the amount to be added to Western Power's asset base would include any depreciation of assets that have been in use for a period of time. However, Western Power does not agree with the depreciation suggested by GBA of $6.93M, and instead the depreciation should be $4.5M. After considering this value the NFIT amount is $378.9M.

The following **Table 4** presents the changes that Western Power considers are appropriate in response to the ERA's assessment.

Table 4: Western Power accepted reduction to NFIT

Technical areas	Paragraph	ERA suggested reduction to NFIT $M	Western Power accepted reduction $M	WP comment
Design of the conductor to 85 C	66	0.5	-	WP standard design applied. Achieves added capability whilst cost is not material.
Undergrounding portion of the Pinjar to Cataby 132 kV line	67	3	-	Options were considered in detail. Selected option is best value and cost differences are not material
Transformer sizing at Three Springs Terminal	68	1.07	-	490MVA sizing is a more efficient and lower cost choice for meeting likely future loads and allowing optimal network development.
KML design of the Eneabba Terminal to Three Spring Terminal line	76	5.175	-	KML selected an appropriate design standard at the time of commitment. Inappropriate to apply an optimised design from hindsight.
Depreciation of assets purchased from KML Three Springs Terminal - $2.69M Eneabba Terminal – Three Spring Terminal line - $3.73M Eneabba Substation – Eneabba Terminal line - $0.51M	83	6.93	4.5	WP accepts that KML assets will be depreciated prior to inclusion in asset base. WP applies 60 year asset depreciation life for lines and 50 years for substation.
	Total	16.675	4.5	

Figure 5: NPC for new terminal substation in the northern section

1. Establish terminal station in December 2016

OPTION 1	Establish terminal station in December 2016						Year Ending 30th June								
All figures in Millions		Reference	Western Power Specific or Not	Escalation Type	Present Value	Total Nominal	-1	0	1	2	3	4	5	6	7
Category	Detail						2010	2011	2012	2013	2014	2015	2016	2017	2018
Capital Expenditure	Labour	See "Supporting Calcs." worksheet	Western Power	2	-12.61	-24.32	0.00	0.00	0.00	0.00	0.00	0.00	12.16	12.16	
	Materials	See "Supporting Calcs." worksheet	Western Power	3	-11.35	-21.89	0.00	0.00	0.00	0.00	0.00	0.00	10.94	10.94	
			Western Power	0	0.00	0.00									
			Western Power	0	0.00	0.00									
	Risk Allowance	See "Supporting Calcs." worksheet	Western Power	1	-1.44	-2.77	0.00	0.00	0.00	0.00	0.00	0.00	1.39	1.39	

Output NPV = $32.42M

2. Establish terminal station in December 2017

OPTION 2	Establish terminal station in December 2017						Year Ending 30th June								
All figures in Millions		Reference	Western Power Specific or Not	Escalation Type	Present Value	Total Nominal	-1	0	1	2	3	4	5	6	7
Category	Detail						2010	2011	2012	2013	2014	2015	2016	2017	2018
Capital Expenditure	Labour	See "Supporting Calcs." worksheet	Western Power	2	-11.40	-24.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.16	12.16
	Materials	See "Supporting Calcs." worksheet	Western Power	3	-10.26	-21.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.94	10.94
			Western Power	0	0.00	0.00									
			Western Power	0	0.00	0.00									
	Risk Allowance	See "Supporting Calcs." worksheet	Western Power	1	-1.30	-2.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.39	1.39

Output NPV = $30.49M

NPV difference between Options 1 and 2 = $1.93M

4 Incremental Revenue Assessment

4.1 Incremental revenue test

Responses to the incremental revenue test issues raised in the Draft Determination are provided as follows.

4.1.1 Use of existing transmission prices

ISSUE RAISED BY THE AUTHORITY

Paragraph 27:

"…the [incremental revenue] test evaluates the amount of incremental revenue that would be derived from the new loads made possible by the augmentation, measured at existing transmission prices…"

WESTERN POWER'S RESPONSE

Western Power’s estimate of incremental revenue

- Western Power determines the appropriate nodal price to apply at a new node based on the principles defined in Appendix A of the Price List Information, *Price Setting for New Transmission Nodes Policy*. Under this policy the nearest relevant exit node is chosen as a reference point upon which to derive the price for the new node.

- There are no 330 kV exit nodes at Eneabba Terminal or Three Springs Terminal. The current 330 kV system originating from Northern Terminal only extends as far as Neerabup Terminal, but there are no published exit point prices at either of these nodes.

- Given this, the Malaga substation was selected as the “electrically nearest” facility with a published exit point price to be used as a proxy reference node. The published Malaga 132kV exit point price reflects a notional 330 kV price at Northern Terminal or Neerabup, with the Northern Terminal 330/132 kV transformers being the only facility between the 330 kV and 132 kV busbars. The published nodal price at Malaga is used as a reasonable approximation of an applicable 330 kV exit point price at Neerabup, which is the reference node used to derive the 330 kV exit point price at Three Springs Terminal.

- The methodology used to then derive the use of system price at Three Springs Terminal takes into account the costs of the line from Neerabup to Three Springs. Excluding the cost of this line would not be a reasonable reflection of the actual cost of transporting electricity at 330 kV to Three Springs.

- The price that will apply for supply to Karara Mining Limited (KML) will be based on the approach outlined above. Consequently, Western Power's determination of future incremental revenue is based on the expected contractual outcome. It is important to note that Western Power’s final decision to proceed with the MWEP project is conditional on finalizing a commercial agreement with KML, which will include security over the forecast revenue stream.

– Our approach to determining the appropriate price is consistent with MJA's[9] advice that "Estimates of anticipated incremental revenue should therefore be based on the most realistic forecast of the price that would be charged to new customers".

The Authority's estimate of incremental revenue

– The Authority considers that 132 kV Use of System price at the existing Three Springs zone substation is the relevant price to determine incremental revenue. We do not consider this to be an appropriate reference point because no 132 kV assets will be used to provide supply to the new Three Springs Terminal once the 330 kV MWEP (Southern Section) is built.

– We understand that the Authority considers that the incremental revenue must be developed on this basis to ensure that existing customers will not be worse off because of the new connection. We have undertaken further analysis to ensure that this will not be the case and this is presented in Section 6.

– The use of the 132 kV exit point at Three Springs Terminal yields a price of $73.50/kW/annum. This is substantially lower than the estimated $125.46/kW/annum calculated by Western Power as the nodal price on the application of the approved Price Setting for New Transmission Nodes Policy.

– We do not believe that the actual incremental revenue can be ignored as it is what will drive the actual impact on other customers. To the extent that the actual incremental revenue is greater than the estimate used by the Authority, the actual benefit to customers from the connection will be greater.

– Western Power anticipates receiving in the order of $(..)[10] million in nominal dollars from KML over 20 years for Stage 1 CMD assuming a continuous operation over that period and conservatively allowing for a 38 per cent decline in the Three Springs terminal nodal price when Extension Hill Pty Ltd connects. This estimate is much higher than the Authority's estimate. Should Extension Hill not proceed, the revenue from KML will be substantially higher than the forecast used in this assessment, as the reduction in nodal price will not eventuate.

4.1.2 Inclusion of a prospective load that has not yet made a Final Investment Decision

ISSUE RAISED BY THE AUTHORITY

Paragraph 30:

"…Western Power's proposed incremental revenue includes a prospective load that is yet to reach Final Investment Decision. Given current global economic circumstances, there remains some element of risk that the full amount of incremental revenue may not eventuate…"

WESTERN POWER'S RESPONSE

– The Final Investment Decision (FID) (or equivalent) is an important development milestone for many connection applicants (both prospective loads and generators). However, not all connection applicants will formally announce that they have reached the FID milestone.

[9] MJA report page 8
[10] Commercial in confidence

- In addition, Western Power is frequently in discussions with connection applicants who have not yet reached FID. Developing economically efficient augmentations of the shared network requires consideration of expected future loads, not just those that have reached FID. The cost of new connections can be reduced if the likelihood of multiple connection applicants proceeding to connection within a specified timeframe (e.g. time required to constructed new facilities) are not ignored. This is consistent with good industry practice.

- The usefulness of Western Power's Monte Carlo risk model is that it provides a means of estimating the level of latent (as opposed to actual) demand based on underlying economic variables.[11] This allows Western Power to assess the impact of changes in relevant underlying economic variables (e.g. iron ore prices) have on the likelihood of latent demand being realized. This is the model we relied upon in our initial submission.

- As economic conditions improve, the risk of latent demand not being realized decreases. Nevertheless, the risk of latent demand not being realized is always present.

- Western Power manages this risk by requiring connection applicants to provide bank security and other forms of legally binding assurance for forecast future revenues. Thus, Western Power's approach to demand-side risk management associated with new facility investment is more stringent than requiring connection applicants to reach FID.

4.1.3 Risk modelling transfers risk from Western Power to existing customers

ISSUE RAISED BY THE AUTHORITY

Paragraph 112:

"…the Authority is concerned that the use of a probabilistic model for the purposes of NFIT provides a mechanism for the transfer of risk from Western Power to existing customers…"

WESTERN POWER'S RESPONSE

- The application of NFIT requires a reasonable estimate of the future revenue from new customers be determined. Western Power has conducted extensive, sophisticated probabilistic analysis of the Extension Hill and KML mining loads to develop a robust expected view of the future incremental revenue.

- The model was reviewed by the Authority’s own economics consultant who found it “is considered a reasonable approach in lieu of firm commitment from iron ore producers”[12].

- In deciding whether the approach adopted by Western Power provides an appropriate allocation of the funding risk for the project to existing customers, the Authority has indicated that they will consider the views of existing customers.

[11] Western Power adopted the Monte Carlo risk quantification method following previous guidance provided by the Authority in NFIT determinations that suggested that Western Power's maximum 15 year rule specified in the Contributions Policy was inappropriate when applying the incremental revenue test.

[12] Marsden Jacob Associates (15 November 2011). New Facilities Investment Test for Western Power's Mid-West Energy Project (Southern Section), p. 8

- We note that all of the submissions received by the Authority support that the MWEP (Southern Section) passes NFIT and therefore accept the risk allocation implied by Western Power's calculation of incremental revenue.

- Western Power held two stakeholder forums on the MWEP (Southern Section) Draft Determination. These were held on 30 November and 1 December in Geraldton and Perth and attended by a broad cross section of stakeholders representing both existing and future customers[13].

- Feedback received at those forums indicated broad stakeholder support for the risk allocation implied in our NFIT assessment.

4.1.4 Incremental operating costs have been understated

ISSUE RAISED BY THE AUTHORITY

Paragraph 114:

"Incremental operating costs have been understated in the incremental revenue test as they have not been based on the full capital expenditure. The approach to calculating incremental operating costs for the new transmission assets – as only applying 2.1 per cent to the $112 million difference between the full capital expenditure of $383 million and the net benefits of $271 million from the next section – omits a significant component of transmission network operating costs. The Authority considers that Western Power should include the full amount of network operating costs in the incremental revenue calculation. "

WESTERN POWER'S RESPONSE

- The requirement under the incremental revenue test is set out in part (b) of the definition of anticipated incremental revenue in the *Electricity Networks Access Code 2004* (**Access Code**):

  (b) "…the present value (calculated at the *rate of return* over the same period) of the best reasonable forecast of the increase in *non-capital costs* directly attributable to the increased sale of the *covered services* (being the covered services referred to in the expression "increased sale of *covered services*" in paragraph (a) of this definition…"[14]

- The operative part of the above definition is the phrase "best reasonable forecast". In determining the best reasonable forecast, Western Power has established a trade-off between: the actual incremental non-capital costs likely to be incurred as a result of operating and maintaining the MWEP (Southern Section); and the administrative burden of determining the actual level of incremental non-capital cost across hundreds of connection applications every year.

- Western Power operates according to an administratively simple (and widely accepted) rule when determining the incremental non-capital cost. Through many years of experience in application, Western Power is satisfied that this rule provides the best reasonable forecast of incremental non-capital cost.

[13] A summary of issues raised by stakeholders at these forums has been published on Western Power's web site at http://www.westernpower.com.au/documents/networkprojects/midwest/qa_nfit_discussion.pdf
[14] Italicised phrases have defined meaning under the Access Code.

– The rule is to determine the annual non-capital cost as the product of the network-wide ratio of non-capital to capital cost and the residual capital cost after deducting the amount attributable to the safety & reliability test and the net benefits test.[15]

– Further, given the nature of the investment being a small number of large assets, Western Power is confident that the actual incremental non-capital cost for the proposed new assets would be no more than $2 M per year as outlined in our initial submission. By contrast, Western Power believes that a charge of $8 M per year, which results from the Authority's suggested calculation[16], would be demonstrably excessive.

[15] Publicly available evidence of this method being applied is provided in Western Power's NFIT pre-approval application titled *Installation of a second 330/132 kV transformer at Kemerton Terminal and construction of a 132 kV transmission line to supply Binningup Desalination Plant*. Figure 4 on page 21 shows that $5.96 M for the brought forward shared asset cost was allocated to the Water Corporation. Figure 5 on page 22 shows this as an input to the incremental revenue determination. Figure 5 also shows that the incremental operating and maintenance cost was $146,699 per year. This is the product of 2.46% (the appropriate AA1 ratio of: the network-wide annual transmission operating and maintenance cost; and the capital value of the transmission network) and $5.96 M.
Refer to: http://www.erawa.com.au/cproot/9023/2/20101112%20D54066%20Western%20Power%20-%20%20Submission%20of%20Proposed%20Capital%20Project%20for%20Binningup%20NFIT%20Pre-Approval.PDF [accessed 23 November 2011].

[16] Economic Regulation Authority (14 November 2011). *Draft Determination on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section) Submitted by Western Power*; paragraph 114.
Refer to: http://www.erawa.com.au/3/1178/48/mid_west_energy_project_southern_section_augmentat.pm [Accessed 5 December 2011]

5 Net Benefits Assessment

5.1 Net benefit test

Western Power's responses to the issues raised by the Authority with respect to the net benefits test are presented in this section.

5.1.1 Extent of new wind turbine generation in the 'without' augmentation scenario

ISSUE RAISED BY THE AUTHORITY

Paragraph 34:

"…if wind is favoured to the degree suggested by the modelling, it is not clear why there is not more new wind entry in the 'without' scenario…"

WESTERN POWER'S RESPONSE

– As indicated in Table 5, Western Power has received wind turbine generation connection applications that total 2,916 MW. Accommodating this amount of new wind turbine generation capacity presents serious technical challenges for operation of the network. In assessing these for the MWEP (Southern Section) economic modelling, Western Power conducted high-level technical and economic analysis. In response to the Authority's Draft Determination, Western Power sought new information and checked the underlying assumptions.

Table 5: Total capacity across SWIS connection applications from prospective wind turbine generators by region

Load Area	DSOC (MW)
East	543
Metro	0
North	1,621
South	752
	2,916

Source: Access queue database as at 18 November 2011

– With respect to technical considerations in the 'without' case[17], the relevant regions are East and South. According to Western Power's Access Queue as at 18 November 2011, there is a total of 752.3 MW of wind turbine generation in the South, and 543 MW in the East. The technical issues with respect to the East are already well documented in the information that Western Power provided in its Collgar NFIT submissions. Namely, that the Eastern Goldfields 220 kV transmission line is currently capacity constrained.

– With respect to the South, a recent system study generation in the south west indicated that accommodating the Beenup wind farm would require either: the up-rating of the MU-BTN-MJP 82 line; or the implementation of a run-back scheme. In addition, this study indicated that there is limited capacity in the 132 kV network

[17] Appendix 1 *Explanation and discussion of the generation profiles across the 'with' and 'without' scenarios*, p. 39 provides a brief background of ACIL Tasman's analysis and explains what is meant by the so-called 'with' and 'without' cases.

between Muja and the Perth metropolitan area.[18] If the 132 kV loading issue and any resultant reactive issues are resolved, then it would be possible to connect at least another 290 MW of wind generation in the south of the SWIS.

– ACIL Tasman's modelling reflects this advice, which assumes that this restriction is lifted by 2015. Thereafter, wind turbine generation is limited due partly to the assumption that a further step-change in transmission capacity does not occur before 2020 and partly due to the assumed termination of the then Renewable Energy Certificate Scheme in 2030[19]. This is assumed to adversely impact on the financial viability of renewable generation after 2020.[20,21]

– In short, there are significant technical constraints in the transmission network restricting wind turbine generation in all regions where there are high-quality wind resources.

– The cost of overcoming these transmission constraints is the economic issue. It is doubtful that wind turbine generators would be able to self-fund significant upgrades in the transmission network. Consequently, prospective wind turbine generators are likely to wait for major new block loads to assist in providing the funds.

– The key questions are: (i) where are the new block loads likely to locate; and (ii) which transmission constraints are likely to be addressed? The most likely answers are: (i) the prospective magnetite iron ore miners located in the Mid West and Great Southern; and (ii) the MWEP (Southern Section) and the Muja-Southdown transmission line.[22] However, the Muja-Southdown transmission line is unlikely to address the Muja to Perth metropolitan area transmission constraint.

Crowding out effect between projects

– A supplementary issue implied by the Authority's question above is whether there is a "crowding out" effect between the prospective magnetite iron ore miners.[23] That is, would the development of one undermine the investment case of the other? Would building two transmission lines mean that one is grossly under-utilised and impose a net cost to the SWIS electricity market?

– If constructed, the Muja-Southdown transmission line may also facilitate connection of new wind turbine generation. Indeed, the Wind Speed Atlas of Australia[24] indicates areas of strong wind (i.e. faster than 7.2 metres per second) in the Mid

[18] Note that the Muja to Perth 132 kV pathway is likely to be common to all prospective wind turbine generators located in the South West and the Great Southern.

[19] Western Power understands that the LGC scheme, which replaced the REC scheme will terminate in 2030. Therefore, there is no change in the termination assumption.

[20] ACIL Tasman (June 2010), *Net market benefits of Mid West transmission link, Assessment of the market benefits of the southern stage of the proposed Mid West transmission line to Eneabba*; p. 34

[21] Note that the results indicated in ACIL Tasman's results are not sensitive to this assumption since the generation profile in the South Region is identical in both the 'with' and 'without' Base Case cases and the Scenario 5 cases. That is, the impact of the MWEP (Southern Section) is based on the difference between the 'with' and 'without' cases. Given that the South Region is identical in both 'with' and 'without', the difference for this region is zero.

[22] Western Power obtained a Regulatory Test waiver for the Muja-Southdown transmission line on 23 August 2011. Refer to: http://www.erawa.com.au/cproot/9814/2/20110823%20Publication%20-%20Western%20Power%20RT%20Waiver%20for%20PA%20to%20Supply%20Southdown%20Mine%20-%20FD.pdf [accessed 28 November 2011].

[23] This would potentially change the generation portfolio between the 'with' and 'without' scenarios.

[24] Refer to: http://www.energy.wa.gov.au/cproot/2469/2/mean-wind-speed.pdf

West and the Great Southern. Given the choice between these two regions, the decision by wind proponents is likely to be influenced by the cost of connection and the incremental cost of alleviating the Muja to Perth metropolitan area transmission constraint.[25]

- Given these development options, it is worthwhile considering whether these options are mutually exclusive. In other words, what impact would development of the South Region option have on the MWEP (Southern Section) option? To answer this question, it is necessary to consider competitive outcomes both in iron ore mining and in generation.

Competition between iron ore miners

- Given that Karara Mining Limited, Extension Hill Pty Ltd and Grange Resources are all prospective magnetite iron ore producers, it is likely that the rate of development of these projects will be influenced by the same underlying economic factors. The infrastructure challenges appear approximately the same. All three appear to have sound commercial support from Chinese steel producers. Karara is substantially more advanced in its delivery than either of the other projects.

- In theory, these mines might be considered to be competitors. However, in reality, effective competition is more likely to occur between regions. For example, between Western Australia, mature iron ore mines located in China, South America, Africa, Canada, and the United States. Analysis previously provided to the Authority indicates that Chinese iron ore mines are several times more expensive than Western Australian magnetite iron ore mines. Indeed, once developed Western Australia's magnetite miners are likely to be in the middle of the global iron ore supply curve.

- The only likely way that development of one iron ore mine in Western Australia "crowds out" other mines located in Western Australia is if they are placed on different parts of the global iron ore supply curve. However, in the few fundamental aspects that make a difference, the prospective magnetite iron ore miners are virtually identical.[26] Hence, there is good reason to believe that they are located on the same part of the supply curve.

- There is a clear inter-regional difference between the Pilbara hematite iron ore mines and the prospective Mid West and Great Southern magnetite mines. Pilbara hematite mines would be likely to continue to operate in economic conditions that would force the Mid West and Great Southern mines into care and maintenance. However, there are plenty of iron ore mines located in other regions of the world that are higher cost than all of the Western Australian iron ore mines.

- Ultimately, the relative position of the Mid West and Great Southern iron ore mines with respect to non-WA competitors largely boils down to whether the cost of overcoming infrastructure barriers present in Western Australia offset the freight

[25] Connection costs are likely to be in the order of $20 M to $50 M plus any contribution to augmentation of the shared network determined not to meet NFIT.

[26] The main difference appears to be the size of the each iron ore resource. The Southdown Iron Ore Project appears to have a smaller resource, but is according to Grange Resources, still highly prospective with reason to believe that the total resource may be as high as a billion tonnes.

savings resulting from Western Australia's relative proximity delivers relative to Africa and South America.[27]

- According to some reports[28], the bulk shipping penalty for shipping iron ore from Brazil (relative to Western Australia) to China is a minimum of USD 12.50 per tonne. For a 10 milllion tonne annual production rate, that equates to $125 million per year[29]. The annual charge per 330 kV transmission line is approximately $40 million. The net result is an annual $85 million cost advantage for Western Australian iron ore mines.

- Western Australia would enjoy a similar cost advantage over West Africa.

Competition between wind turbine generators

- ACIL Tasman has demonstrated that wind turbine generators currently represent the lowest cost form of large-scale renewable generation. However, there is competition between prospective wind turbine generators in the SWIS and between the SWIS and the National Electricity Market.

- According to ACIL Tasman (see Appendix 3 for the latest advice) prospective wind turbine generators north of Pinjar are the most competitive both within the SWIS and nationally. Hence, there is a clear economic advantage in locating new wind turbine generation north of Pinjar.

- With respect to technical considerations, the issues are transmission capacity and system stability. Western Power's analysis indicates that more wind turbine generation can be sustainably added to the SWIS if the prospective magnetite iron ore mines (which are 24/7 operations) connect and operate as planned. These issues were further discussed in Western Power’s pre NFIT submission Attachment 2 Planning Considerations – Section 6, reference DM# 8473229.

- Thus, while there is competition between wind turbine generators connected to the SWIS, there are corresponding increases in demand, leaving sufficient room for wind turbine generators both in the Mid West and the Great Southern.

- However, if the MWEP and the Muja-Southdown transmission projects both proceed, it would be clearly more efficient to connect wind turbine generation equal to the total increase in block load (i.e. summing CMD across all three magnetite mines) in the north of the SWIS rather than the south.

Conclusion

- In summary, the reason why there is not more wind turbine generation is that the 'without' scenario reflects significant transmission capacity constraints that are costly to overcome.

- Additional scenarios could be modelled that reflect other transmission projects. At present, the most realistic is the proposed Muja-Southdown transmission line.

[27] At the margin, sovereign risk and regional differences in taxation may also influence competitive outcomes.
[28] For example, http://antipodeanmariner.blogspot.com/2011/03/vale-brasil-400000-dwt-very-large-ore.html
[29] Assuming AUD 1 = 1 USD and equivalent iron content in shipped ore.

However, given that the Muja-Southdown and MWEP (Southern Section) demand drivers are not competing, the Muja-Southdown scenario would be largely irrelevant.

- If based on purely economic conditions, the most likely outcome is that either: both the Muja-Southdown and MWEP (Southern Section) projects are implemented; or neither are implemented.

- Given the difference in efficiency between wind turbine generation in the north relative to the south, the most efficient outcome is to add the new generation in the north.

5.1.2 Robustness of the ACIL Tasman assumptions

ISSUE RAISED BY THE AUTHORITY

Paragraph 133:

"…ACIL Tasman has advised Western Power that the move to the LRET scheme should see little change in the price of Large-scale Generation Certificates (LGCs) compared to the REC prices. ACIL Tasman subsequently advised Western Power that this reduces renewable energy generator revenues from LGCs in the net benefits calculation by around 6.0 per cent. This change is material and the value of the identified net benefits needs to be revised by Western Power to reflect this…"

WESTERN POWER'S RESPONSE

- ACIL Tasman has provided additional advice of the impact of the change from the REC scheme to the LGC scheme. This is provided in Appendix 3.

- Figure 1 in ACIL Tasman's letter indicates that project LGC prices are now estimated to be approximately $10 lower than the original REC scheme price projections. This impact, along with other factors identified by ACIL Tasman, reduces the viability of prospective wind farms south of Pinjar relative to those located in the eastern states. However, prospective wind farms located north of Pinjar are still nationally competitive.

- In short, the lower LGC scheme price enhances the competitiveness of the Mid West wind farms relative to other locations across the SWIS. This increases the net benefit of the MWEP (Southern Section).

- If the MWEP (Southern Section) does not proceed, it is likely that the SWIS will lose most of the anticipated LGC revenue to the eastern states.

ISSUE RAISED BY THE AUTHORITY

Paragraph 134:

"…The recently announced Clean Energy Future (CEF) policy has been estimated by the Commonwealth Treasury to lead to a somewhat different carbon pricing trajectory going forward. Carbon prices at 2020 are now expected to be lower – for example, the estimated price of emissions permits at 2020 has declined from around $39 per tCO2e under the CPRS to $29 per tCO2e under the CEF…"

WESTERN POWER'S RESPONSE

- ACIL Tasman's analysis indicates that the reduction in the projected CO_2e price is largely offset by marginal increases in load growth and LGC prices.

- Moreover, given that the CO_2e price projection is the same in the 'with MWEP' and 'without MWEP' cases, any impact of a net decrease would be irrelevant to the estimated net benefits.

ISSUE RAISED BY THE AUTHORITY

Paragraph 135:

"…The IMO has proposed a WEM rule change for capacity credits for intermittent generation, including wind. In particular, it is proposed that the methodology for determining the capacity credits of intermittent generation be changed from an assessed average over a three year period – which allows wind farms a capacity factor of around 40 per cent of their name plate capacity – to a methodology which would more accurately value the contribution of intermittent generation in times of peak demand. It is likely that the proposed rule, which has yet to be adopted, would result in significantly lower capacity credits for intermittent generation…"

WESTERN POWER'S RESPONSE

- As indicated in ACIL Tasman's response (see Appendix 3) the impact of reductions in revenue is an increase in the advantage of wind farms located north of Pinjar relative to those located south of Pinjar.

- Comparing ACIL Tasman's original analysis with the latest, this proposed change has a marginal impact only. It is clear that the cost of connecting to the SWIN has a substantially larger impact than any other variable.

5.1.3 Choice of counterfactual scenarios

ISSUE RAISED BY THE AUTHORITY

Paragraph 140:

"…Western Power has adopted ACIL Tasman's Scenario 5 for estimating the net benefits. This counterfactual scenario is based on Western Power's high load growth scenario, which incorporates Karara Stage 1 and Stage 2 and Extension Hill Stage 1 magnetite CMD loads. In line with paragraph 25, the Authority considers these assumptions are at the more optimistic end of the confidence interval…The Authority considers that the medium scenario would see less wind connection in the Central region, as the case for additional wind is supported by the amount of proximate new block loads…"

WESTERN POWER'S RESPONSE

- Western Power's choice of the high load scenario was based on the demand-side risk analysis that indicated that, given prevailing economic conditions, Extension Hill Pty Limited is highly likely to proceed to connection within a year or two of the planned energisation date of the MWEP (Southern Section) transmission line. Western Power's High Load forecast is the only forecast that includes Extension Hill Pty Limited. It is noted that the Authority supported this view in its Regulatory Test decision.

- Western Power's Central Load forecast excludes Extension Hill Pty Limited on the basis that it has not yet reached FID. This implies a switch from ACIL Tasman's Scenario 5 to the Base Case. As noted by MJA, this results in a reduction in market benefit by $11 million to $225 million.

- However, Western Power has determined that the MWEP (Southern Section) provides scope to add 155 MW of wind turbine generation without any new block loads, arising from the network reinforcement relieving existing power transfer constraints. This means that under the base case the amount of new generation does not decrease with a reduction in forecast load. In other words, the additional 155 MW would more than compensate for the loss of Extension Hill Pty Ltd. ACIL Tasman's latest analysis demonstrates that up to 1,035 MW could be added if determined solely by economic factors. This means that below this amount, it is only the technical constraints that are binding.

- On this basis, Western Power maintains that the total net benefit estimated in Western Power's original submission holds and is a conservatively low estimate of benefits likely to accrue.

- On balance, there has been no material change to underlying economic conditions and given the constraint placed on ACIL Tasman's modelling, Western Power believes that Scenario 5 is the most reasonable choice. Nevertheless, system studies conducted by Western Power indicate that the restriction of new wind turbine generation to 230 MW imposes a conservative bias in the results. If Extension Hill Pty Limited develops as expected, the amount of new wind turbine generation that could be accommodated is likely to be 355 MW i.e. larger than the 230 MW originally estimated.

5.1.4 Estimated benefits for consumers

ISSUE RAISED BY THE AUTHORITY

Paragraph 146:

"…the Authority notes that this transfer to electricity consumers is likely to be overstated. This is because ACIL Tasman [sic, recte Tasman's] PowerMark model assumes that all energy on the SWIN is transacted in the STEM. Hence, any reduction in STEM prices at the margin benefits all loads. However, this transfer may be constrained, to the extent that a significant proportion of electricity is dispatched under long term bilateral contracts. In the case of bilateral contracts, any reductions in the costs of generation would be retained by the generators…"

WESTERN POWER'S RESPONSE

- Western Power has given this issue extensive consideration over a period of more than 18 months. This consideration included reference to both the Access Code and the Authority's views on this test as explained in various NFIT issues papers.[30]

- Western Power notes that the Authority accepts the main result, namely that there is likely to be a meaningful reduction in generation cost.[31]

- The issue, given the Authority's guidelines on how to apply the net benefit test, is the extent to which generators (as a group)[32] pass the cost saving, derived largely

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[30] For example: Economic Regulation Authority (August 2011), *Issues Paper: New Facilities Investment Test Application for Western Power's Mid West Energy Project (Southern Section) Submitted by Western Power*, p. 18;
http://www.erawa.com.au/cproot/9837/2/20110826%20-%20D71777%20-%20issues%20paper.pdf

[31] Western Power acknowledges the Authority's concerns with respect to the magnitude of the net benefit, which is addressed in other parts of this submission.

[32] Western Power recognises that there may be winners and losers within the generation sector as a result of long-term changes to the generation portfolio. The key issue is whether there is a net benefit after deducting any benefit transfers between generators. In this respect, it is important to realise that the source of the benefit is largely a cost reduction in natural gas, which is used as fuel to generate electricity. Given this fuel cost is sourced from outside the electricity market, this is eligible for consideration in the net benefits test a viable candidate for inclusion in the new facilities investment test. Gas-fuelled generators potentially earn less revenue, but are assumed to reduce

from a reduction in purchases of natural gas, to all or a large proportion of network users.

– The Access Code defines net benefit as follows:

"**net benefit**" means a net benefit (measured in present value terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in (as the case may be):

(a) the covered network; or

(b) the covered network and any interconnected system.

– A reasonable interpretation of this definition is that the net benefit must be received directly by the electricity market (defined as the group: generators, electricity transporters, electricity consumers). The main purpose is to exclude consideration of positive externalities (e.g. increased mining royalty payments to government as a by-product of electricity use in mining).

– The net benefit test determines whether there will be a net benefit, not whether the benefits will be transferred between market participants in a particular way. In other words, if one or more generators manage to capture the net benefit through participation in the market to the exclusion of everyone else, this could be a result of other factors and does not result does not result in the failure of the test.

– Based on this reasoning, Western Power does not accept the Authority's interpretation that speculation on the transfer of benefits results in the failure of the test.

– We note that MJA reached a similar conclusion to Western Power, finding that "… for the purposes of the NFIT it is irrelevant whether the benefits accrue to generators or customers and therefore the distinction between beneficiaries is not critical to the analysis."[33]

5.1.5 Net Benefit Associated With the Deferral of Other Network Reinforcement

Network deferral benefit

Issue raised by the Authority

Paragraph 149:

"The Authority does not have a problem in principle with this assessment. Further, the Authority considers that the assessment of the 'without' scenario is supported in Western Power's application. However, it considers that there is a lack of information provided in the application to support the 'with MWEP (southern section)' net present cost estimate of $164 million. Supporting material is referenced by Western Power to be at Attachment 2 of its application. However, the figure of $164 million does not appear anywhere in that Attachment 2.40 Accordingly, the Authority requires more information on this element of the analysis in order to make its determination on the network deferral benefit of $26 million."

fuel costs. Thus, there is virtually no change in profit. The renewable generators that have displaced the gas-fuelled generators could capture the majority of the benefit.

[33] MJA report page 12

Western Power's response

- In Attachment 2[34] of Western Power's original NFIT submission, the NPC for the options considered are reproduced in Table 6 below.

Table 6: NPC ($M) of options considered for Northern Section

Option		Forecast Scenario		
		Central	High	Low
1	Protection upgrade, Statcom, New line ENB-MNT	170.3	190.3	139.7
2	Protection upgrade, SVC, new line ENB-MNT	174.9	194.9	143.5
3	Protection upgrade, new line ENB-MNT	192.3	205.6	145.1
4	Protection upgrade, statcom, new line ENB-TS	184.6	211.9	155.8
5	Protection upgrade, statcom, thermal upgrade of transmission lines	211.4	244.2	170.6
6	Protection upgrade, statcom, Three Springs 330/132kV	159.8	189.8	137.1

- The least cost option 'without' MWEP (Southern Section) is Option 1. The cost of this option is $190.3M. This is considered as the base option in Attachment 2 of Western Power's NFIT submission, which the 'with' MWEP (Southern Section) is compared with.

- The 'with' MWEP Southern Section (Three Springs 330/132 kV) is Option 6 and under high forecast scenario the cost of this option is $164M. This is the cost for the additional works required to implement this option which is possible if Three Springs Terminal is delivered through the MWEP (Southern Section) project. If this cost is deducted from the cost of Option 6, then the NPC of Option 6 will be $164M as shown in Table 7.

Table 7: NPC of the Northern Section baseline and with MWEP options

	Central	High	Low
Option 1 (Baseline option)	$170 M	$190 M	$140 M
Option 6 (with MWEP)	$134 M	$164 M	$111 M
Net deferral benefit	$ 36 M	$ 26 M	$ 29 M

- The deferral benefit is obtained by subtracting the NPC of Option 1 from Option 6. For the high forecast scenario, the net deferral benefit is $26M.

[34] Attachment 2: Planning Reports: Mid West Energy Project (southern section) Planning Considerations (Dm# 8473229); and Mid West Energy Project (northern section) Planning Report (DM#6957480)

5.1.6 Net Benefits Associated With Reduction in Network Losses

The connection of the 330 kV MWEP (Southern Section) will provide the additional benefit of a reduction in losses for the underlying forecast. A large component of this load (more than 80 per cent of the underlying load) will flow through the 330 kV line compared to the 132 kV network. The ERA and its consultants accepted the net benefits associated with the reduction in network losses.

The loss reduction benefit assumes an energy price of $36/MWh. The modelling conducted by ACIL Tasman suggests future energy prices could easily exceed this level and could increase the loss reduction benefit to the order of $27 million.

5.1.7 Summary of Net benefits

Western Power's revision of its net benefits estimates indicates that the original assessment of $271 million is still valid, and is considered to be conservative.

Finally, it should also be noted that Western Power has not included estimates of the substantial State-wide economic development benefits that are highly likely to be facilitated by the MWEP (Southern Section). This is due to Western Power's interpretation of the Access Code that these benefits should be excluded from the net benefits test.[35] However, that is not to say that the State economic development benefits do not exist. Indeed, available information suggests they may be of similar size or larger than the estimated direct market benefits.

[35] For example, there may be a significant increase in State employment, government tax revenue, mining royalties etc. Under the Access Code, Western Power believes that these benefits would justify subsidy from government for the MWEP (Southern Section).

6 Customer Impact Assessment

6.1 Customer impact

Western Power's response to the issues raised by the Authority with respect to price risk borne by existing customers is presented in this section.

The Authority requires us to demonstrate that existing customers will not be worse off as a result of this project.

This section provides further analysis to demonstrate that this is the case and that the project does pass the NFIT.

6.2 Assessment

Western Power has assessed the impact on prices to existing customers as a result of this project using the Discounted Weighted Average Tariff (DWAT)36 approach and the AA3 cost-of-service model for determining tariffs37. This approach assesses the difference between prices with and without the additional investment and load. Where the DWAT increases, it would be expected that the investment would result in increased prices.

Two scenarios were examined:

1. Without the MWEP (Southern Section); and
2. With the MWEP (Southern Section).

In scenario 1, the forecast capital expenditure for the MWEP (Southern Section) and KML's annual energy requirement were excluded. This established a baseline transmission DWAT of $31.753 per MWh.

In Scenario 2, KML's energy requirement was added and the model used to solve for the maximum asset value that could be added without increasing DWAT above $31.753 per MWh. The result was that $248 million dollars (nominal) can be added to the capital base with no increase in the average transmission network tariff. This means that $248 million in capital could be added to the capital base without affecting prices given the additional load expected. For comparability to previous analysis, this amount was discounted to July 2010 dollars, resulting in an estimate of $223 million.

Deducting this amount from the estimated capital cost of $379 million results in a residual capital cost of $156 million. Adding this amount would increase transmission tariffs. However, this project is estimated to deliver net benefits of $271 million. Therefore there is a net benefit to the market of $115 million. This provides a benefit-cost ratio of 1.7 for customers which confirms that the MWEP (Southern Section) is economically efficient.

It is acknowledged that the current AA3 cost-of-service model assumes the forecasts included in Western Power’s proposed access arrangement revisions currently being reviewed by the Authority. It is expected that these assumptions will be revised through the process. However, plausible variations in the AA3 parameters are not expected to materially affect the outcome.

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[36] Economic Regulation Authority (August 2011). *Issues Paper, New Facilities Investment Test Application for Western Power’s Mid West Energy Project (Southern Section) Submitted by Western Power*, p. 17. Refer to: http://www.erawa.com.au/cproot/9837/2/20110826%20-%20D71777%20-%20issues%20paper.pdf

[37] A copy of the financial model used will be provided to the Authority.

7 Conclusions

1. We believe the efficient costs are $378.9 million which is the amount in our initial submission less an adjustment for depreciation.

2. Incremental revenue can vary significantly and is affected by changing assumptions.

   We accept that the Authority's methodology might be appropriate to consider whether the project will impact on existing customers.

   We believe the DWAT test does this more effectively and shows that there will be a net increase in tariffs but this is expected to be less than the benefits.

   In any event, the actual revenue Western Power expects to receive is much greater than the Authority's estimate. Under the revenue cap arrangements, customers will actually benefit by more than that assumed by the Authority.

3. There are significant benefits from this project which outweigh the additional costs.

4. Taking all of these factors into account, Western Power submits that value of the proposed MWEP (Southern Section) investment that satisfies the NFIT is the full estimated project cost of $378.9M.

Appendix 1 Explanation and discussion of the generation profiles across the 'with' and 'without' scenarios

Western Power commissioned ACIL Tasman to conduct the market benefits study as part of the application of the net benefits test.[38] ACIL Tasman's analysis is based on a model (called *PowerMark WA*) of the generation portfolio in the South West Interconnected System (**SWIS**). This model simulates changes in the generation portfolio over a period of 20 years in response to generation parameters such as generation fuel prices, operating and maintenance costs, thermal efficiency, marginal loss factors etc.

In order to assess the market impact of the MWEP (Southern Section) ACIL Tasman specified two cases: (i) a case that includes the MWEP (Southern Section); and (ii) a case that excludes the MWEP (Southern Section).[39] Case (i) is the 'with' scenario and Case (ii) is the 'without' scenario.

The impact of the MWEP (Southern Section) on the generation portfolio can be assessed by comparing the change between the 'with' and 'without' scenarios. Table 16 shows 'snapshots' of the Base Case new entrant generation as at 2015, 2020, 2025 and 2030 for the 'with' scenario. Table 17 shows comparable 'snapshots' of the Base Case new entrant generation for the 'without' scenario.[40] The *only* difference between these scenarios is the MWEP (Southern Section). Thus, comparison of the 'with' and 'without' Base Case scenarios identifies the impact of the MWEP (Southern Section) on the generation portfolio.

Comparing tables 16 and 17 indicates that the South Region connects an additional 285 MW of renewable generation in 2015 and then remains unchanged across all remaining years. For the Central Region, the tables show that 486 MW of new renewable generation connects in the 'with' scenario by 2015 while only 256 MW connects in the 'without' scenario by 2015. This reflects a difference of 230 MW. The level of new renewable generation remains unchanged for all subsequent years in each scenario.

By contrast, base-load generation in the North Region is higher in the 'without' case than the 'with' case. This reflects the need to install generation north of Eneabba to support the forecast growth in block load. In all subsequent years, this difference is maintained.

Comparing the renewable generation difference to the base-load difference indicates 70 MW more renewable generation in the 'with' case than base-load generation in the 'without' case. This can be reconciled by considering differences in capacity factor. Renewable generation is likely to achieve a 40% capacity factor[41] in the Mid West.[42] This indicates an effective 92 MW of renewable generation. Delivering the same effective base-load generation implies a capacity factor of 57.5%.

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[38] ACIL Tasman (June 2010), *Net market benefits of Mid West transmission link, Assessment of the market benefits of the southern stage of the proposed Mid West transmission line to Eneabba*; commissioned by Western Power.

[39] Ibid, p. 1.

[40] Ibid., p. 34

[41] Capacity factor is a measure of the utilisation rate for generation. It is defined as actual annual generation divided by potential annual generation (McLennan Magasanik Associates (August 2008) *Installed capacity and generation from geothermal sources by 2020*, p. vi; available at: http://www.pir.sa.gov.au/__data/assets/pdf_file/0006/78846/AGEA_Final_Report.pdf [accessed 22 November 2011]).

[42] This capacity factor is higher than typically experienced elsewhere in Australia and is indicative of the superior wind resources available in the Mid West region.

This pattern of generation change reflects the underlying assumption that the new block load occurs north of the transmission constraint that the MWEP (Southern Section) is seeking to release. If the MWEP (Southern Section) does not proceed, then the only way to supply electricity to the new block loads is to place a base-load generator north of the transmission constraint. The relatively low capacity factor effectively means that the cost of generation in the constrained North Region would be higher than in the rest of the SWIS. If the MWEP (Southern Section) does proceed, then the new block loads can source generation services at a lower cost. In addition, new load growth occurring throughout the SWIS can be supplied by a mixed portfolio of renewable and thermal generation. This has the effect of delivering a cost saving as reflected in ACIL Tasman's modelling.

Appendix 2 Western Power Line Crossing Report

MWEP (southern section) Planning Considerations Addendum 7
Pinjar HV Line Crossing Considerations (DM# 8836738)

Mid West Energy Project

(southern section)

Planning Considerations Addendum

7 - Pinjar HV Line Crossing Considerations

Date: November 2011

DM# 8836738

Contents

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document.

Table 1: Abbreviations and Acronyms

Abbreviation / Acronym	Definition
the Code	*Electricity Networks Access Code 2004*
CTB	Cataby Substation
EMD	Emu Downs Substation
ENB	Eneabba Substation
ERA	Economic Regulation Authority
MWEP	Mid West Energy Project
NFIT	New Facilities Investment Test
PJR	Pinjar Substation
RGN	Regans Substation
TST	Three Springs Terminal
WPN	Western Power Network

1 Introduction

As part of the Mid West Energy Project (MWEP) (southern section) reinforcement, a number of detailed design considerations which had a significant impact on the project cost and performance were investigated. These design considerations have been discussed in a separate paper, Mid West Energy Project (southern section) Planning Considerations (DM8473229).

In addition to these design considerations, a decision has been taken on how to undertake a crossing of the new double circuit 330kV line over an existing double circuit 132kV line, 4km north of Pinjar substation (PRJ).

This report will assess different options available for this additional key detailed design considerations with a recommendation provided. This is considered number 7 of the planning considerations, and this report is an addendum to this report.

The recommended option and other options evaluated are for the purposes of demonstrating that Western Power is efficiently minimising costs in relation to the MWEP (southern section) reinforcement and providing the lowest sustainable cost over a reasonable period of time to demonstrate compliance with NFIT.

On the estimated construction costs only, the underground solution is estimated to be $0.25M more expensive that the cheapest above-ground crossing solution. This costs differential is considered minor, and does not include some of the constructability issues that would arise for either of the above-ground crossing solutions.

The cost differential does not factor in additional network costs that would be associated with any possible overhead crossing design, and in particular does not also take into account the risk cost associated with the possibility of a conductor falling onto the undercrossing, which has been evaluated at between $0.4M and $2.7M.

Combining the risk cost associated with a conductor failure, and the costs of construction, the selected option (underground solution) is the lowest cost option, in addition to being technically superior to other available options.

2 Options Investigated

2.1 Introduction

4km North of Pinjar Substation, the proposed new NBT-TST DC 330kV power line crosses the existing DC 132kV line. A solution is required to ensure that the crossing of the two double circuit steel tower lines can be undertaken at the lowest total cost option that is technically possible

This crossing requires a detailed investigation and is treated differently from the other crossings of 132kV lines on this project because:

- The other crossings have lower existing conductors, so allowing lower cost standard 330kV towers to be built at the crossing.
- The other lines at the crossings can be taken out of service with less system disturbance. Some are able to be taken out of service for the duration of the stringing works.
- As they have lower phase heights, this allows cheaper live-line scaffolding if the lines can only have shorter outages – and even in these cases do not require such restrictive outages.

The existing 132kV line is only 40m from the new 330kV line, has a 45 degree deviation at the crossing, and the tower are tall at these locations, hence this HV line crossing is particularly problematic.

The short distance between the angle tower and the 330kV conductors (40m separation) precludes the use of a standard gantry under-crossing that could be made using the existing angle tower, as the short distance means that conductor separation cannot be achieved directly onto such gantries. The 45 degree deviation at the crossing also precludes a simple lowering of the conductors at this location also a standard crossing undertaken by Western Power.

The crossing is also more difficult to be undertaken at an early stage in the project by the proximity of the existing wood-pole line, which precludes the construction of any centreline gantries on the new line route prior to demolition of the existing line.

2.2 Option Summary

As part of the initial planning and scoping of the NCR project, this crossing was investigated in 2008, using both internal and external line designers and constructors, with the goal of providing a cost effective, technically feasible recommendation.

Three options were identified that were viable solutions to this crossing, these options being:

1. Above ground 330kV undercrossing the existing 132kV
2. Above ground 132kV undercrossing 330kV
3. Underground 132kV undercrossing 330kV

A diagram of each option is included in attachment 1, which shows the major items of construction and demolition required for each of these options. The options were investigated at a high level, without significant design, as it was apparent at an early stage that the underground solution was both technically and economically viable and provided Western power with the best "whole-of-life" cost option. It was noted that further design on either option 1 or 2 would have brought up other issues that would have added to their costs.

There was a fourth possible option, to cross the new 330kV line over the existing 132kV line without modifying the 132kV line. However the use of the standard suite of 330kV towers to cross the existing 132kV line is not possible, given the height of the 132kV line. One-off towers of a height to undertake this crossing would be prohibitively expensive, and require special installation techniques not used in this state before.

In addition, the costs and the risks associated with the supply and installation of live-line scaffolding above the 132kV line, required to allow stringing of the 330kV conductors would prohibit this option. The proximity of this crossing to RAAF Pearce and GinGin suggests that excessively high towers would not have received approvals.

2.3 Technical Implications

2.3.1 Option 1 (330 under 132)

This option relies on bringing the 330kV line under the existing 132kV double circuit line.
To ensure clearance are met, this solution requires replacing one suspension tower south of the crossing with a terminal tower, adding an additional terminal tower north of the crossing, and the supply of 4 gantries to support the under-crossing. A gantry on each side of the line crossing is required to allow construction to be undertaken without long outages of the 132kV lines, and also to ensure that clearances from both conductors and the ground are maintained.

Pros:

- Can be constructed relatively easily with only vicinity permits required, and without needing major changes to the existing 132kV lines (subject to more detailed design).

Cons:

- May not be able to be constructed without requiring the 132kV line to be lifted at the crossing, dependent on final design clearances.
- Brings 330kV line closer to the ground. This option has the highest public safety risk – may be subject to higher vandalism, and structures will be a higher traffic hazard.
- Difficulty of maintenance – works on either of the upper 132kV circuits may necessitate outages of both the 330kV lines underneath – this would include removing these circuits either temporarily or permanently. This would have serious ramification for the Mid West network after the 2nd side has been energised.
- Highest system risk – single 132kV conductor fault can trip and damage both 330kV circuits and black-out the complete Mid West Region

2.3.2 Option 2 (132 under 330)

This option relies on bringing the existing 132kV lines under the new 330kV lines.
This option is more complex and expensive than would be expected for such an

under-crossing, due to the proximity of the existing angle tower at the crossing, which needs to be removed during the works. To implement this crossing the initial design indicated a need for 4 terminal poles, 3 angle poles, and 4 suspension poles.

This option is technically the most complex to implement as it requires significantly more outages on both the double circuit line and the existing wood pole line. Construction cannot be carried out until the wood pole line has been removed. This option also requires temporary wood pole work and prolonged outages to build around and then demolish the corner double circuit tower prior to installation of new angle poles. This could require high cost generation during these outages.
During stringing of the 330kV line there will be additional construction issues due to the need to string over two closely placed lines. This option is by far the riskiest in regards to planning, outages and safety.

Pros:

- Cheapest solution based on construction costs for the crossing

Cons:

- Has the potential of being highest construction costs dependent on the outage and temporary supply arrangements than will be need for construction.
- Cannot be constructed until the wood-pole line has been removed, as the under-crossing occupies the same space as the existing line. This would have a high risk to the schedule.
- Will be difficult if not impossible to construct the 330kV line once undercrossing has been constructed. To enable live-line scaffolding to be erected will require 2 concurrent outages of both 132kV lines, which cannot happen without significant generation support, and at shoulder periods. This will further limit the time construction on the 330kV line can occur. Alternatively, separate scaffolding may be used for each line; however this would require greater separation of the lines, which would also have cost, design and environmental issues.
- Broken conductor falling on 132kV crossing will blackout all 132kV substations North of Pinjar to (and including) Eneabba

2.3.3 Option 3 (Underground 132)

This option relies on undergrounding the existing 132kV lines from a point south of the existing angle tower to a point to the west of the new 330kV line and access roads. It requires 4 terminal poles, 4 transition poles, and 2 lengths of underground cable.
This option offers a number of construction and operational advantages. The cable and transition poles can be installed ahead of any outages and will allow the 330kV line construction and stringing to proceed completely unhindered. This option will require minimal outages on all 132kV lines, and no concurrent outages on both circuits. It will make maintenance and operation of both lines simpler and remove any possibility of either line affecting the other adversely.

Pros:

- Minimises outages of existing lines.
- Undergrounded section allows unhindered access for construction of the 330kV line.
- Undergrounding, foundations and preparatory works can be carried out at any time, with existing wood-pole line still in service

- Outages can be undertaken one line at a time for short periods.
- Allows future maintenance to be undertaken on any circuit (132kV or 330kV lines) with no effect on any other circuit.
- Removes the risk of a fallen conductor.

Cons:

- Highest cost option based purely on construction costs.

2.3.4 Conclusion – Technical Evaluation

Option 3 (underground solution), is recommended as the technically optimal option, as it:

- will have the simplest construction
- will have the least disruption of existing 132kV lines during construction
- has the least schedule constraints
- will require minimal outages, and no outages will be required during the 330kV line stringing.
- reduces structures and conductors near publically accessible line access tracks
- will have no on-going issues with maintenance of one circuit affecting other circuits
- completely mitigates the risk of a fallen conductor, hence enhancing overall system security

2.4 Cost Evaluation

A technical solution for each option was established, and based on the high level design an order of magnitude level cost estimate was made for each of the 3 options. The estimated cost for each of the three options are:

Crossing Option	Estimated Direct Construction Costs
Option 1 - 330kV under 132kV	$3.0M
Option 2 - 132kV under 330kV	$2.9M
Option 3 - 132kV underground under 330kV	$3.1M

Under these comparative estimates, the procurement and construction cost for the underground option is only $0.25M higher than the cheapest above-ground option.

As part of this risk assessment and cost assessment, a cost-based risk assessment of the risk of conductor failure was made over the undergrounding option.
This assessment came up with a risk value associated with option 1 over option 3 of between $0.36M to $2.67M. The risk value associated with option 2 over option 3 was between $0.02M to $0.36M.

This reduces the differential between options, and indicates that combining construction costs and the risk values brings option 3 to the same costs as options 1 and 2, without taking into account the technical benefits of option 3, nor other un-costed outage costs, which could be a significant cost for Option 2.

While the risk of a particular span failing is low, it does happen (a span of 330kV transmission line did fail recently on 2nd September), and so does have an input into the decision making process.

2.5 Other Issues

There are a number of other factors outside of the risk and cost assessment that further justify the choice of the underground solution.

Environmental.
This area is within land nominated as “bush forever” and comes under Federal as well as State Environmental control. Clearing of these areas is required to be minimised. In addition to problems with environmental approvals for additional clearing that would be required for options 1 and 2, the environmental offset costs would increase for these two options.

Outages.
For options 1 and 2, there are longer outages required for the existing circuits, and possibilities of a double outage of both circuits to enable the construction to be undertaken. In these instances, significant generation would be required to be run, adding to the total project costs, and there would be the possibility of additional portable generation required to be supplied and run for the period of the outages, which would add costs comparable or greater than the $0.25M differential.

Any outages of these lines concurrently would require significant generation support at Regans, Cataby or Eneabba substations.

3 Conclusion

It is recommended that the undergrounding solution (option 3) is implemented for this line crossing. The recommended solution is technically and economically the optimal solution. It provides a technically superior solution, is simpler to construct, has the lowest interference with the 330kV line build, is a safer solution, and is the lowest whole-of-life cost option.

While the underground option is $0.25M more expensive than the cheapest overhead crossing, this cost differential is considered to be far outweighed by the system risks, constructability issues, outage requirements and safety issues that would be encountered by either of the overhead crossing options. The overhead crossing solutions will also have on-going maintenance issues.

4 Ongoing Review

As part of Western Power’s ongoing review of designs and options analysis to ensure cost effective project implementation, a recent review has been taken on the decision to proceed with a full underground solution.

While undertaking detailed design on this crossing, Western Power has investigated the possibility of undergrounding one circuit only. This would retain the existing angle tower for one circuit using the lower cross-arms only.

However to achieve the required phase to phase clearances, one phase would need to be moved off the tower, and so an additional 3 extra steel poles would be required for this phase. It has been estimated that the costs of the addition poles required to swing the remaining circuit around, coupled with the additional height required for the 330kV line to cross this overhead circuit, would be higher than undergrounding the second circuit, and would negate some of the benefits of having the other circuit underground.

Hence the recommendation to underground both circuits is still believed to be the most cost-effective solution.

Attachment 1 – Option Diagrams

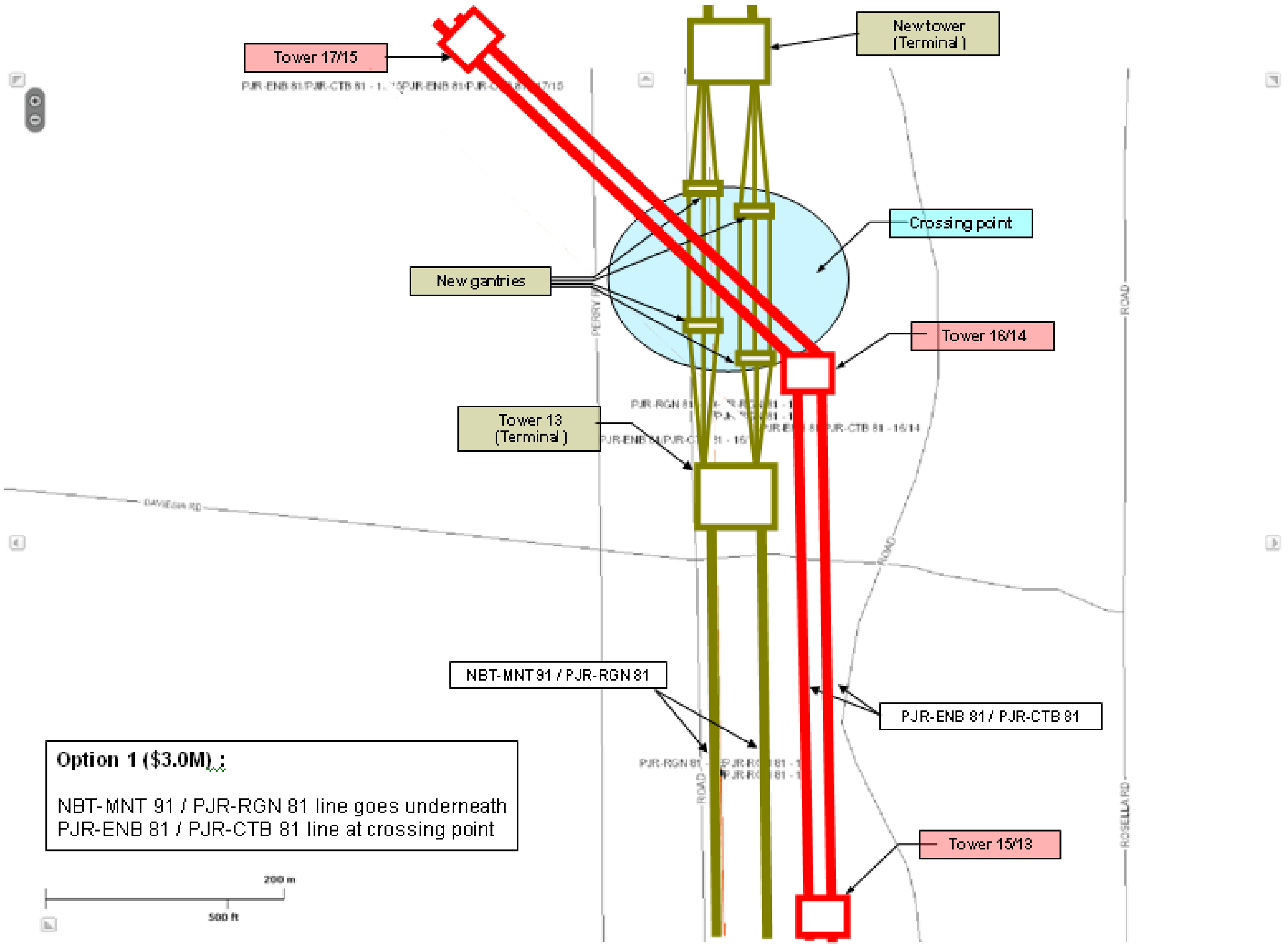

Figure 1: Option 1

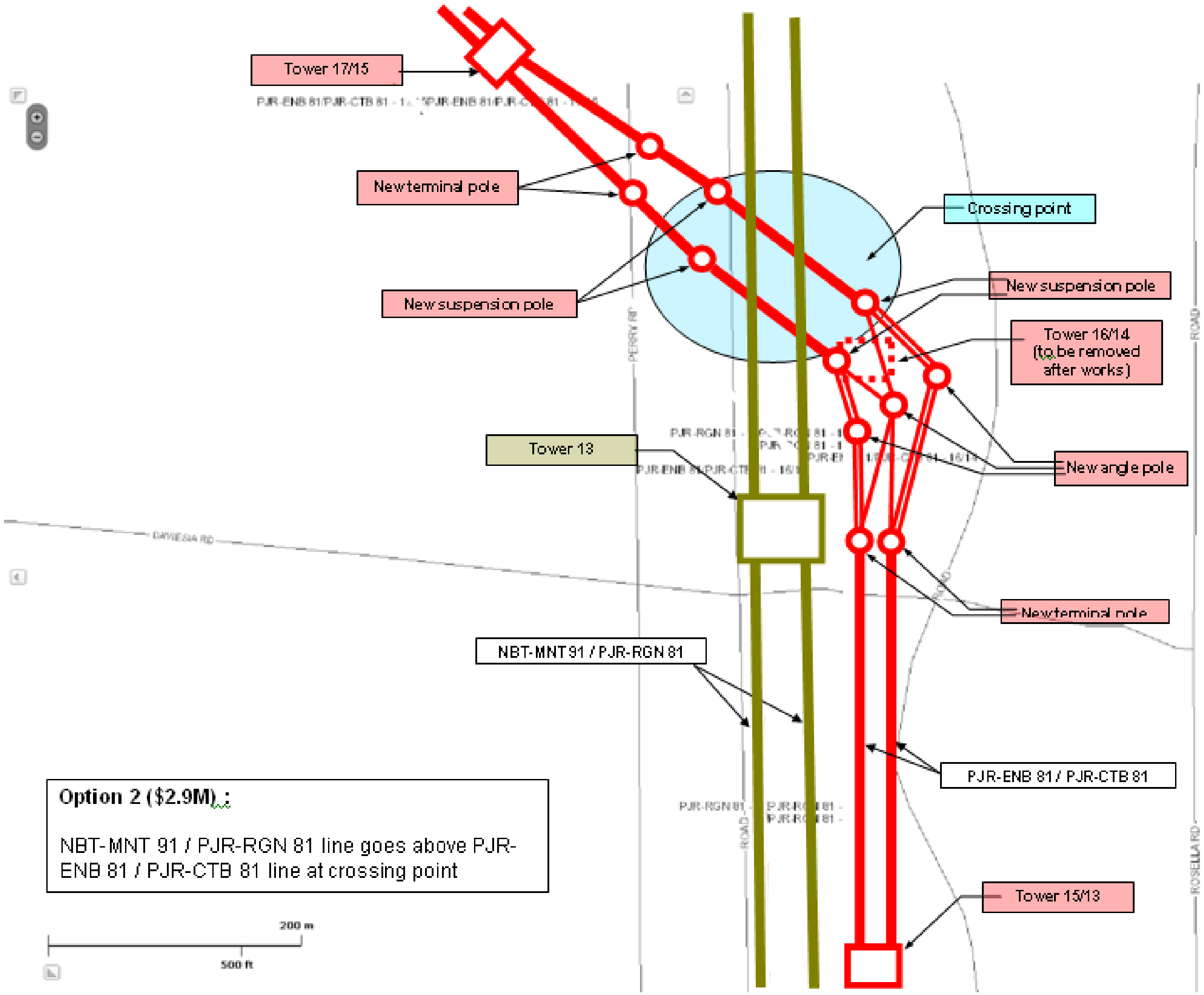

Figure 2: Option 2

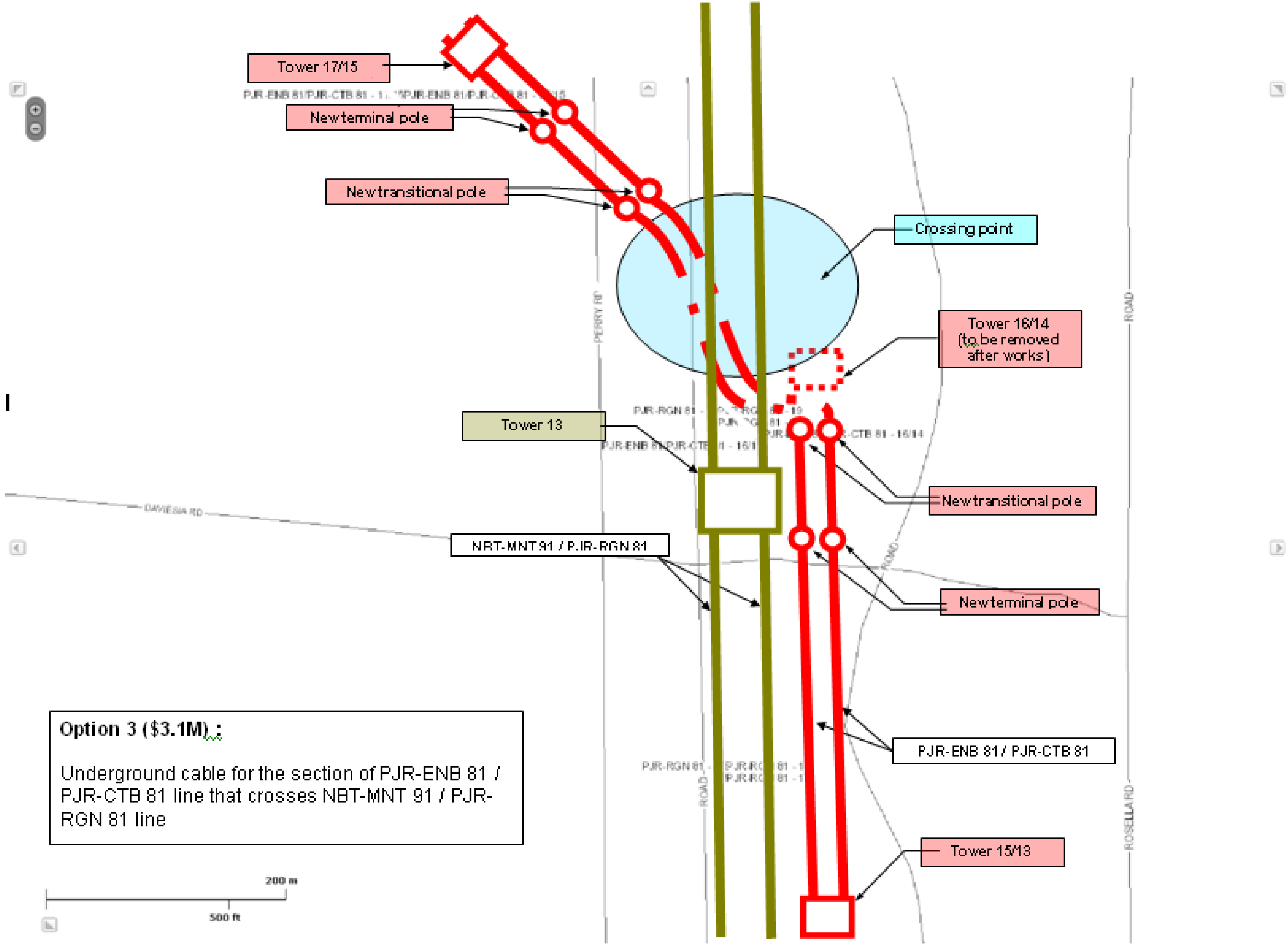

Figure 3: Option 3

Figure 4: Aerial photo of the crossing point

Appendix 3 ACIL Tasman Report

ACIL Tasman letter dated 4 December 2011 (DM# 8900565)

CONFIDENTIAL

ACIL Tasman
Economics Policy Strategy

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4 December 2011

Peter Mattner
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Pricing and Regulation
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ACIL Tasman's response to the ERA's Draft Determination on the Mid West Energy Project

Dear Peter

This letter sets out ACIL Tasman's response to ERA's Draft Determination on the Mid West Energy Project (MWEP). It comments on the Draft Determination with respect to the estimation of net market benefits as undertaken by ACIL Tasman as part of the NFIT application for the project.

Use of STEM prices

The Authority expressed the view that ACIL Tasman's use of STEM prices may not be a reliable reflection of market prices.

In an earlier response to a similar query ACIL Tasman made the observation that the reduction in electricity market price because of the additional wind farms, as modelled by ACIL Tasman, has no impact on the market net benefit of the MWEP in that the benefit to electricity users of lower prices is balanced by the reduction in revenue to electricity generators. In the same way, if the market price had increased because of the MWEP then the increased generator revenue would be offset by the increased cost to electricity users. This means a change in market price, whatever the direction of the movement, does not affect net benefits. It also means that the level of market prices is not important in determining market net benefits of the MWEP.

This means that the overall net market benefit to Western Australia effectively comes from: changes in generation costs with reduced fuel costs; and increased revenue from Large-scale Generation Certificates (LGCs) (previously known as RECs) more than offsetting the higher capital costs. A key factor is that without the additional wind generation in Western Australia, the LGC revenue would accrue to generators in other States.

ACIL Tasman is aware that the wholesale prices in the WEM are, in general, currently contained in bilateral contracts with the Short Term Energy Market (STEM) accounting for only a small percentage of energy supplies. While no one knows, it may be presumed that bilateral contract prices are currently linked in some way to generation costs and do not rely to any great extent on STEM prices. Presumably the bilateral contract prices take into consideration the generation cost of competing plant including potential new entrants. The effectiveness of the STEM market to provide reliable price signals to the market is limited by the current practice of generators opting to generate their bilateral contracts. This is, presumably, to protect market share rather than use the STEM to adjust contract positions to genuinely minimise costs.

ACIL Tasman's pricing methodology is based on the rational assumption that, in the longer term, as participants better understand the market mechanisms and the ensuing benefits, trading on the STEM will become more widespread and the STEM price will become a valuable indicator of wholesale electricity prices. ACIL Tasman uses short run marginal cost (SRMC) offering in its modelling of the STEM. In this modelling ACIL Tasman adds open cycle gas turbine (OCGT) peaking plant to provide the capacity required by the IMO until, as time passes, the STEM price plus capacity payment reaches a level which justifies the addition of the lowest cost base load new entrant[1]. The STEM price plus net capacity payments at that time will be sufficient to cover the long run marginal cost (LRMC) of the lowest cost base load new entrant. In this way, the modelled STEM price plus capacity payment contained in the ACIL Tasman modelling reflects the cost of the base load new entrant generator and as such will provide important price signals to bilateral contract arrangements.

The timing and capacity of new wind farms included in the STEM modelling is determined separately using ACIL Tasman's national model of the renewable energy sector *(RECMark)*. This modelling shows that Western Australia, with its very good wind resource and higher wholesale electricity prices, is still one of the most attractive locations in Australia. The additional wind farm capacity due to the MWEP, given that SRMC of wind is close to zero, keeps STEM prices lower by causing deferment of the next lowest cost base load new entrant. This occurs in the ACIL Tasman modelling because the additional wind farm capacity is lowest in the plant SRMC merit order, thereby lowering the SRMC of the marginal generator, which in turn results in a lower STEM price.

ACIL Tasman is of the view that the approach taken to estimate market prices is appropriate in that the prices reflect new entrant generation costs and in this way, as the market matures, the STEM price will provide a valuable guide to the wholesale electricity price. Furthermore, the ACIL Tasman SRMC offering methodology, which is consistent with the market rules, results in lower prices when additional wind farm capacity is added.

ACIL Tasman Scenarios

ACIL Tasman does not accept that the choice of scenarios was arbitrary. The Base Case and six scenarios, each having with and without MWEP cases, were modelled and presented in the ACIL Tasman report. The scenarios were designed to capture the likely effects on net market benefits compared with the Base Case of variations in:

- load forecast
- wind load following costs $10.00 or 15.00/MWh

[1] The lowest cost base load new entrant is the new generator, either coal or gas fired, which meets the load at lowest cost.

- capacity credit allowance of either 40% or 20% of wind farm capacity
- wind configuration to generally reflect different transmission development alternatives
- other assumptions in the Base Case such as carbon pricing, fuel costs, plant outages, etc. are the same as used in all Scenarios.

The accent in constructing the scenarios was to test the effects on net market benefits of changes in the various in key wind generation assumptions because these were judged to be the most significant likely cause of variations in net market benefits.

A description of the Base Case and the six scenarios is contained in the Introduction to the ACIL Tasman report on pages 1 and 2. The Base Case and each scenario examines the net market benefits with and without the MWEP.

Base Case: This is the reference case against which the various scenarios are compared to assess the effect of key assumptions on the net benefits. It was based on medium forecast load growth, greater new wind capacity in the case with MWEP than without but with no new wind north of Eneabba. It uses $10.00/MWh load following costs for wind farms and capacity credit allowance of 40% of wind farm capacity. The net benefits in the Base Case were estimated at $225 million.

Scenario 1: This Scenario included the same assumptions as the Base Case except that it had no additional wind in the case with the MWEP. This scenario clearly demonstrated that the additional new wind farm capacity was providing the greatest boost to net benefits from the MWEP. The net benefits were estimated at $16 million which clearly demonstrates that it is the additional wind farm capacity under the with MWEP case which provides the bulk of the net benefits. In ACIL Tasman's view this is a critically important finding in understanding the source of the net benefits.

Scenario 2: This is the same as the Base Case but with additional new wind capacity north of Eneabba. This was to understand the additional net benefits which could flow if the transmission reinforcement is extended north of Eneabba. Scenario 2 suggested that a further increase in wind farm capacity north of Eneabba increases net benefits further. The net benefits were estimated at $331 million suggesting the additional wind capacity north of Eneabba would add $116 million to the net benefits. This scenario provided worthwhile insights for consideration of augmentation north of Eneabba although was not used by Western Power to justify the Three Springs extension to the MWEP.

Scenario 3: This is based on the same assumptions as the Base Case but a reduced capacity payment for wind farms - down to 20% of their capacity from the current 40%. This scenario was to provide an understanding of a reduction in capacity allowance for wind to test the effect of the proposed rule change on the competitiveness of the WA wind farms in a national setting. The net benefits were estimated at $224 million. This compares with net benefits of $225 million in the Base Case and means that such a rule change is unlikely to have any marked effect on net benefits.

Scenario 4: This is based on the same assumptions as the Base Case except for an increased load following costs of \$15.00/MWh and capacity credits reduced to 20% of capacity for wind farms. The net benefits were estimated at \$207 million compared with \$225 million in the Base Case. Taking both rule changes into account reduces net benefits as the national competitiveness of WA wind farms is further eroded. However the modelling results show that there are still substantial net benefits.

Scenario 5: Same assumptions as the Base Case but with high load growth. The net benefits were estimated at \$236 million which is higher than under the \$225 million under the Base case which means the higher load growth contributes a further \$11 million to net benefits. This scenario demonstrates that higher load growth brings a modest increase in net benefits through reduced generation cost due to enhanced utilisation of lower cost base load base load plant given that the increase in load is assumed to come from high load factor block loads.

Scenario 6: This is based on the same assumptions as the Base Case except for the higher load forecast and an increased load following costs of \$15.00/MWh for wind farms and capacity credits reduced to 20% of capacity for wind farms. The net benefits were estimated at \$219 million. To evaluate the impact on net benefits of higher load growth this scenario should be compared with Scenario 4 which had \$207 million net benefits or \$12 million less. It also shows that the higher load growth does not quite offset the effect of the two rule changes because the net benefits are some \$6 million less than those in the Base Case.

Wind farm development for the Base Case and Scenarios was generally determined using *RECMark* modelling (apart from Scenario 1 where plant was not changed in the with and without MWEP cases) which resulted generally in more new wind capacity in the case with MWEP than in the case without MWEP. Apart from Scenario 2, it was further assumed that there were no new wind farms north of Eneabba because of a lack of transmission capacity. Again, apart from Scenario 2, the study generally assumed the transmission reinforcement to Eneabba.

Carbon pricing

Variations in the carbon price trajectory were assessed as not significantly affecting net market benefits and as such were not investigated in the original Scenarios. Although a lower carbon price would be associated with higher LGC prices and be expected to increase net benefits from the MWEP through higher LGC revenues for the additional wind farms in the case with MWEP. While no modelling has been done to check this, we are reasonably certain that there would be no noticeable change in net benefit to electricity consumers through electricity prices as the both with and without MWEP cases would have the lower carbon price.

A lower carbon price will give lower electricity prices and could lead to marginally higher load growth but again because this will apply to both with and without MWEP cases, it will not affect the net benefit.

Finally, a lower carbon price would not be expected to change the future plant program noticeably and thus it would have negligible impact on the net benefits through changes in capital and operating costs of generation with and without MWEP.

This means that the ACIL Tasman estimates of net benefits based on the higher CPRS carbon price would, if anything, be conservative given it was based on higher carbon prices.

Further assessment of wind generation

An important aspect of the estimation of the net benefit was the finding that the MWEP would allow additional wind generation on to the SWIN. The Authority has questioned as to why wind proposals in other areas might not simply replace the ones made possible by MWEP if MWEP was not built.

The extent and timing of new wind generation has been determined by detailed modelling using ACIL Tasman's *RECMark* which is an LP model of the LRET market. *RECMark* determines the timing of renewable projects based on the viability of each project in a national setting. Practical limits based on assessment of industry capability are placed on the level of new installation in any one year in *RECMark* so not all viable projects are constructed at one time.

RECMark contains an extensive database of proposed wind farms and other renewable energy projects across Australia, containing technical and economic characteristics of each of the proposed projects.

The main drivers for the renewable generation projects are:

- plant capital and operating costs (including transmission connection charges and expected load following charges in WA)
- assumed capacity factors - with wind projects capacity factors potentially varying from around 20% to as high as 47%
- normal regional electricity prices (also referred to as black energy prices) including carbon costs across Australia and capacity payments in WA
- LGC prices
- electricity system and transmission limitations (particularly important in WA).

The higher capacity and higher black energy prices generally mean that wind farms in WA are among the most profitable in Australia. However there are a number of recent actual and potential changes which have reduced this advantage including:

- potential increase in ancillary service costs in WA (i.e. the $10 to $15/MWh load following charge)
- generally much higher transmission connection charges in WA which were not fully accounted for in ACIL Tasman's earlier study
- increased black energy prices in eastern Australia due to higher expected future gas prices associated with LNG developments in Queensland

- potential reduction in black energy price for WA wind farms through reduction in proportion of capacity attracting capacity payments
- lower carbon price trajectory
- updated renewable project database including more proposed wind farms in WA and an allowance for the higher transmission connection costs in WA.

However, because of their higher capacity factor of generally around 40%, the wind farms in the north which would rely on the MWEP, would still be among the first to be developed in Australia assuming transmission and system constraints are alleviated; even assuming a transmission connection cost of over $200/kW. However wind farms with capacity factors in the low 30% range, such as those proposed in the south of the SWIN, will be marginalised by these developments particularly with the high transmission connection cost.

With the limited time available it was not possible for ACIL Tasman to completely redo the modelling of the benefits but we have used *RECMark* to investigate the Authority's concern that the MWEP may not necessarily add to total wind generation and thereby not deliver the net benefits flowing from this additional wind generation.

The approach in the *RECMark* modelling was to limit the total wind capacity to a level which just meets LRET for WA which we calculate is around 1700MW of wind capacity. We also notionally limited the wind farm capacity added each year in WA to 400MW. It was beyond ACIL Tasman's capability to assess whether system and transmission limitations might further limit the overall wind capacity in the SWIS.

Preliminary further analysis of the wind farm contribution to summer peak demands in 2011 suggests that WA wind farms contribute around 40% of their capacity to annual system peak and as such a change to market rules regarding calculation of the percentage of wind farm capacity to attract capacity payments may not change the percentage to any marked degree regardless of the chosen methodology.

The list of potential wind farms has been expanded to include all of the more recent announcements and to take into consideration connection inquiries supplied by Western power. The list of potential wind developments used in the latest RECMark modelling is shown in Table 1. It identifies some 2265MW of potential wind farm capacity. The capacity factors shown in Table 1 are generally estimated by ACIL Tasman based on performance of existing wind farms in the respective areas.

Table 1 List of potential wind farm developments in WA used in RECMark modelling

Project	Capacity (MW)	Assumed capacity factor (%)	SWIS Region
Badgingarra	130	40.0%	Central
Carnarvon	5	35.0%	not SWIS
Denmark	1.6	35.0%	South
Milyeannup	55	35.0%	South
Nilgen	100	40.0%	Central
Walkaway 2	94	45.0%	North
Yandin Hill	210	37.4%	Central
Waddi Windfarm	105	37.4%	Central
Dandaragan	190	37.4%	Central
Flat Rocks	150	33.0%	South
Williams	150	33.0%	South
Joanna Plains	80	37.4%	Central
Coronation	62	37.4%	North
Wellstead	178	33.0%	South
Karlgarin	250	33.0%	South-east
Nightwell	150	33.0%	South-east
Wellstead2	105	33.0%	South
Eneabba	250	37.4%	Central

Source: ACIL Tasman analysis and WP connection enquires

The four wind scenarios studied and the results of the *RECMark* modelling are set out in Table 2. Wind scenarios 1 and 2 assume that the MWEP is developed and that there are no transmission limitations in development of the full 1700MW of wind farms. The difference between Wind scenarios 1 and 2 is the transmission connection costs assumed for wind farms south of Pinjar which vary from $217.00/kW to $70.00/kW. Connection costs for the wind farms north of Pinjar are assumed at $217.00/kW based on estimates supplied by Western Power. The reason for varying the transmission connection costs in this instance is to gauge the effect on capacity installed south of Pinjar. Wind scenarios 3 and 4 assume that the MWEP is not developed and that all wind capacity would be installed south of Pinjar assuming different transmission connection costs.

Table 2 shows that with the MWEP being developed (Wind scenarios 1 and 2) there is some 1754MW of wind farm capacity installed on the SWIS. However, there is only 57MW of capacity south of Pinjar regardless of the size of transmission connection charge. This means that the southern wind farms are generally displaced by the higher capacity factor wind farms in the north.

More interesting however is the capacity installed in the south when there is no transmission augmentation north of Pinjar. As shown in Table 2, under Wind scenarios 3 and 4 the capacity installed is only 57MW when the transmission charge of $217.00/kW is applied (see Wind scenario 3). This increases to 795MW under the Wind scenario of $70/kW transmission connection charge as in Wind scenario 4. The most recent wind farm to be connected was the 206MW Collgar wind farm located in a very advantageous position in the transmission system; but even then the connection costs were around $20 million or $97.00/kW. So the $70/kW is probably below that which can be achieved. This suggests that even with a very low transmission connection charge of $70/kW there is room, if the MWEP is developed, for further wind generation capacity north of Pinjar of around 260MW compared with 230MW in our earlier study which would otherwise have been lost to WA.

In other words this analysis suggests that without the MWEP, wind farm development in WA will be restricted. If developed the MWEP is likely to see up to 1220MW of additional generation which far exceeds the 230MW additional Wind farm Capacity estimated in ACIL Tasman's original study and suggests that the original study was very conservative in its estimates of net market benefits and certainly not optimistic as suggested by the Authority.

Table 2 Wind scenarios and RECMark modelling results

	With MWEP		Without MWEP	
	Wind scenario 1	Wind scenario 2	Wind scenario 3	Wind scenario 4
Assumed transmission connection costs ($/kWh)				
North of Eneabba	217(1)	$217	n/a	n/a
North of Pinjar	$217	$217	n/a	n/a
South of Pinjar	$217	$70	$217	$70
Potential wind capacity in WA 2020 (MW)				
North of Eneabba	156	156	0	0
North of Pinjar	1,065	1,065	0	0
South of Pinjar	57	57	57	795
Existing and under construction	476	476	476	476
Total	1,754	1,754	533	1,271

Source: ACIL Tasman
Notes 1: The $217.00/kW transmission connection cost is based on a Western Power estimate of $50million for a 230MW wind farm connected to MWEP

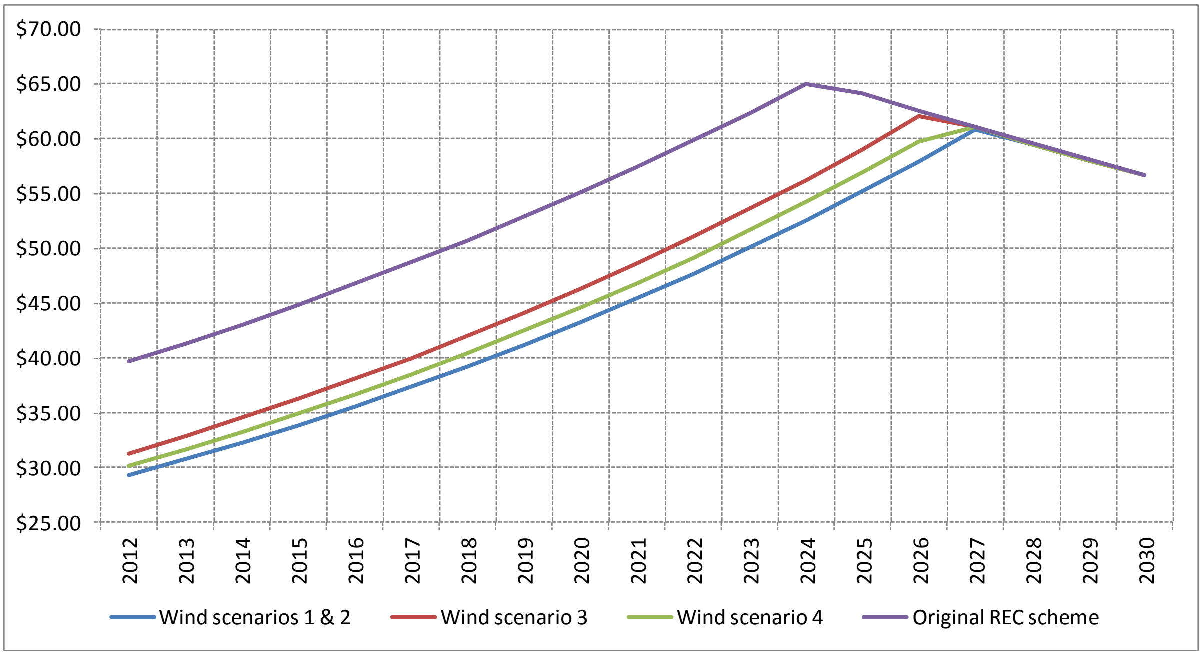
LGC prices and revenues

One output of the *RECMark* modelling is the LGC price which is noticeably lower in the current modelling results than the estimates made in mid 2010 and used in the original study. This has occurred because of the noticeably higher black energy prices now projected in eastern Australia resulting from higher gas prices due to the additional demands from LNG developments in Queensland. As we would expect, Figure 1 indicates that Wind scenarios 3 and 4 have higher LGC prices than Wind scenarios 1 and 2 where the MWEP is developed and lower cost wind farms join the list of potential developments.

ACIL Tasman is concerned that the ERA has arrived at the view that ACIL Tasman has based its estimates on optimistic assumptions, particularly if it was relying on the Marsden Jacobs Report (MJA) to arrive at its assessment of ACIL Tasman's projection of LGC prices. Figure 4 on page 14 of the MJA report comparing the ACIL Tasman REC price trajectory and one made by MMA in 2007 for the Office of the Renewable Energy Regulator is misleading and incorrect. Our price line is based in the latest scheme with a targeted generation of 41,000GWh by 2020 whereas the MMA price trajectory is for the original MRET scheme with a target of just 9,500GWh. These are two entirely different situations and one would expect the lower target to be associated with lower REC prices. Furthermore ACIL Tasman is of the view that, given the bankability of LGCs, a flat price trajectory is incorrect as it ignores the real time value of money.

From a net benefit perspective the lower LGC prices would reduce the net benefits of the additional wind farms. However, the more recent modelling results summarised in Table 2 suggest that the 230MW of additional wind farms from the initial study is very conservative. The more recent modelling shows that could be around 1221MW in 2020 (see Wind scenarios 1 and 2 in Table 2). Applying the revised lower LGC prices to the increase in the additional MW of wind farm capacity from the more recent modelling would give a substantially higher net market benefit associated with the MWEP due to the additional LGC revenue of around $765 million. This compares with the original cases with LGS net benefits of around $192million.

Figure 1 LGC prices



Summary of wind findings

Using updated data on proposed wind farms results in WA gaining a greater share of LGCs nationally particularly from wind farms north of Pinjar. Without the MWEP there would be substantially less wind farms in WA even if transmission connection charges south of Pinjar are assumed at a very low level. The net market benefits through additional revenue from LGCs with the MWEP is estimated at $765 million compared with $192 million in the original study.

Regards

[redacted]

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