westernpower

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

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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 after 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

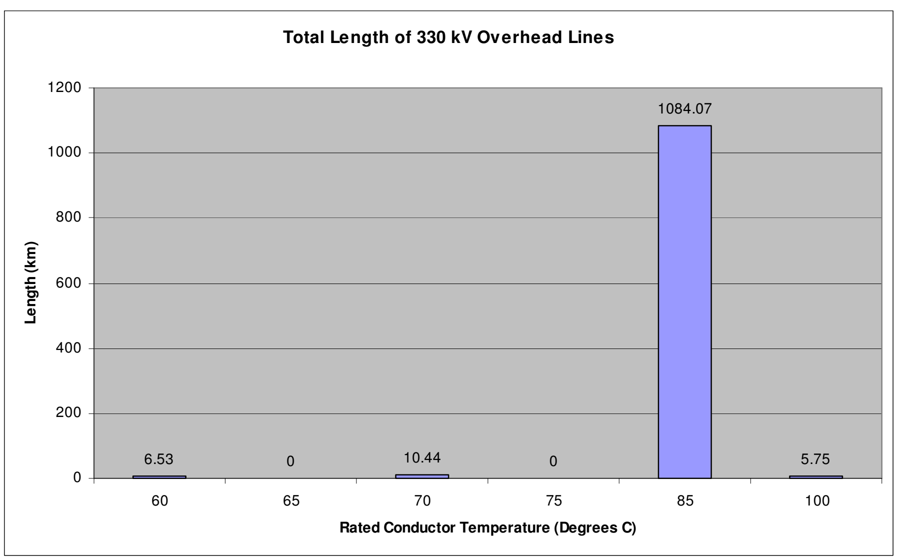
- The Geoff Brown & Associates (GBA) Technical Review Report (Draft 2 – November 2011), released by ERA, has determined that the cost different between the line designed to maximum temperature of 85° C and the lower 75° C is immaterial. In GBA's report it quotes in reference to the conductor design temperature "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

[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

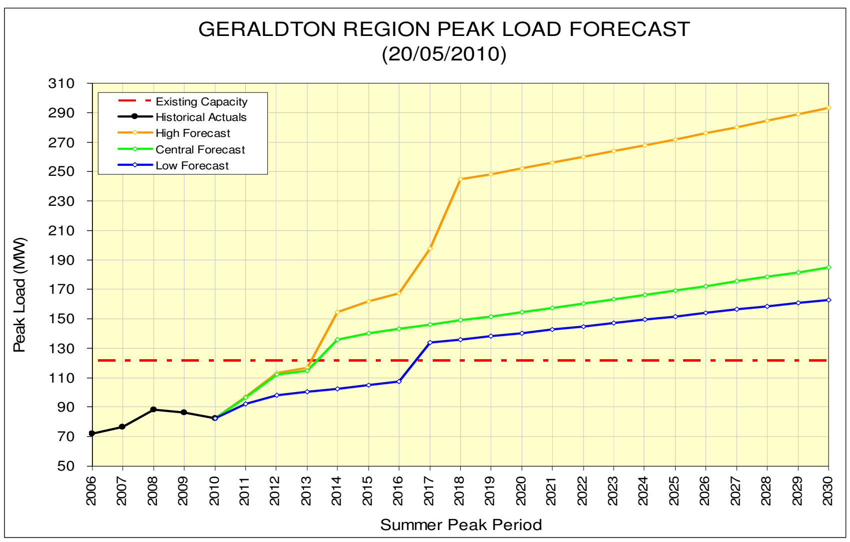
[5] *Cost to customers based on VCR is obtained by: 21MW * 4 hrs * VCR = $4.6M*

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.

- 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].

- 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;

  - 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

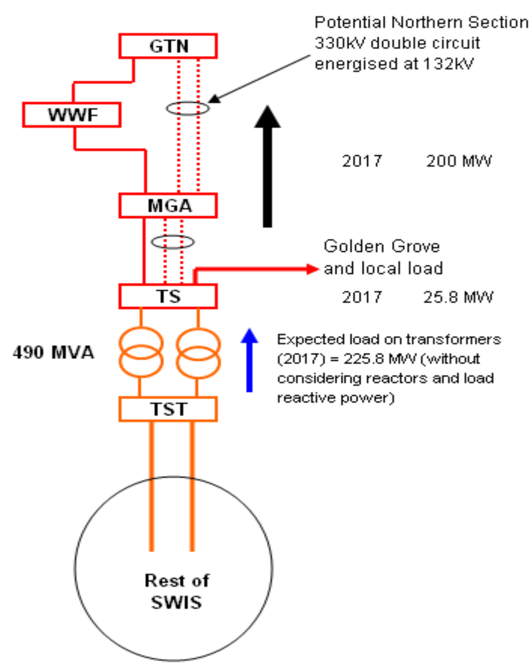
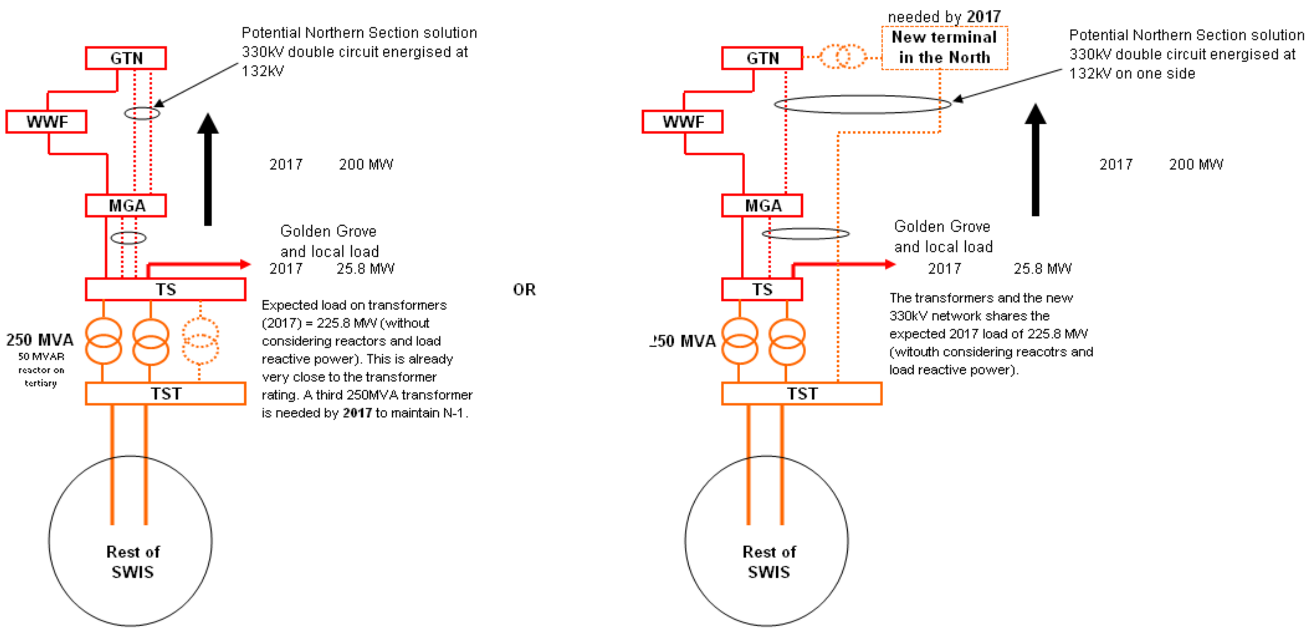


Figure 4: Network with the 250 MVA transformers



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 $336 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.

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[9] MJA report page 8

- 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.[10] 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"[11].

- 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.

[10] 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.

[11] 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[12].

– 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…"[13]

– 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.

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[12] 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

[13] 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.[14]

- 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[15], would be demonstrably excessive.

[14] 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].

[15] 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[16], 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

[16] 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.[17] 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[18]. This is assumed to adversely impact on the financial viability of renewable generation after 2020.[19,20]

– 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.[21] 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.[22] 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[23] indicates areas of strong wind (i.e. faster than 7.2 metres per second) in the Mid

[17] 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.

[18] 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.

[19] 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

[20] 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.

[21] 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].

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

[23] 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.[24]

– 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.[25] 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

[24] 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.

[25] 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.[26]

– According to some reports[27], 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[28]. 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.

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

– Western Power notes that the Authority accepts the main result, namely that there is likely to be a meaningful reduction in generation cost.[30]

– The issue, given the Authority's guidelines on how to apply the net benefit test, is the extent to which generators (as a group)[31] pass the cost saving, derived largely

[29] 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

[30] 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.

[31] 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."[32]

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.

[32] MJA report page 12

Western Power's response

- In Attachment 2[33] 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.

[33] 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.[34] 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.

[34] 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)[35] approach and the AA3 cost-of-service model for determining tariffs[36]. 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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[35] 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

[36] 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.[37] 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).[38] 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.[39] 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[40] in the Mid West.[41] 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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[37] 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.

[38] Ibid, p. 1.

[39] Ibid., p. 34

[40] 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]).

[41] 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)

Appendix 3 ACIL Tasman Report

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