Draft Determination on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section)

Submitted by Western Power

14 November 2011

Economic Regulation Authority

WESTERN AUSTRALIA

Important Notice

A full copy of this document is available from the Economic Regulation Authority website at www.erawa.com.au.

For further information, contact:

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

Contents

GLOSSARY

AA3	Third access arrangement period
CMD	Contracted Maximum Demand
GBA	Geoff Brown and Associates
MWEP	Mid-West Energy Project (Southern Section)
MJA	Marsden Jacobs Associates
NFIT	New Facilities Investment Test
TUOS	Transmission Use of System

DRAFT DETERMINATION

1. On 3 August 2011, the Economic Regulation Authority (**Authority**) received a new facilities investment test application from Western Power submitted under section 6.71(b) of the *Electricity Networks Access Code 2004* (**Access Code**). A version suitable for publication was received on 16 August 2011.[1] The application seeks for the Authority to determine that forecast new facilities investment proposed by Western Power, for the Mid West Energy Project (Southern Section) (**MWEP**), meets the new facilities investment test. The project is estimated to cost $383.4 million and involves the construction of a double circuit 330 kV transmission line between Neerabup and Three Springs and a new terminal station interconnecting the 132 kV and 330 kV transmission systems at Three Springs.

2. In making a determination on a new facilities investment test application, the Authority is required to consult with the public in accordance with the consultation requirements of Appendix 7 of the Access Code. The Authority issued an invitation for submissions on 26 August 2011, with a closing date for submissions of 12 September 2011. As part of this consultation, the Authority prepared an issues paper to assist interested parties in understanding the new facilities investment test and Western Power's new facilities investment test application.[2] Submissions were received from the following parties:[3]

   - APA Group
   - Crosslands Resources Ltd
   - ERM Power Ltd
   - Extension Hill Pty Ltd
   - Karara Mining Ltd (confidential)
   - RPV Developments
   - Shire of Perenjori
   - Synergy
   - Vestas Australian Wind Technology Pty Ltd
   - Wind Prospect Pty Ltd.

3. Western Power's pre-approval application is for a total amount of forecast new facilities investment for the proposed works of $383.4 million. Western Power submits that the entire proposed investment of $383.4 million meets the test of section 6.51A of the Access Code, by virtue of satisfying the new facilities investment test of section 6.52 of the Access Code.

---

[1] Western Power, August 2011, New Facilities Investment Test Pre-Approval Application Mid West Energy Project (Southern Section)- Neerabup to Three Springs Terminal via Eneabba (hereafter referred to as "**new facilities investment test application**").

[2] Economic Regulation Authority, 13 December 2010, Issues Paper: New Facilities Investment Test Application for Western Power's Mid West Energy Project (Southern Section) Submitted by Western Power.

[3] These submissions are available on the ERA's website: http://www.erawa.com.au/3/1178/48/mid_west_energy_project_southern_section_augmentat.pm

4. To assist with its assessment of Western Power's new facilities investment test application, the Authority commissioned independent advice from Geoff Brown and Associates (**GBA**) and economic advice from Marsden Jacob Associates (**MJA**).[4]

5. The Authority published its decision on 3 February 2011 that the proposed MWEP project satisfied the regulatory test under Chapter 9 of the Access Code. Western Power could not commit to the proposed project until it satisfied the regulatory test by demonstrating that the proposed project was the best means of developing the electricity system compared to alternative options such as alternative network investments, investment in generation or management of electricity demand.

6. The purpose of the new facilities investment test is to determine the extent to which the cost of the proposed augmentation may be rolled into the regulated capital base and therefore financed through network tariffs applying to all network users, or alternatively must be financed by some other means (such as capital contributions from specific network users). A service provider is not required to submit a new facilities investment test application to the Authority prior to committing to any expenditure, but may do so if it wishes.

7. For the new facilities investment test to be satisfied, the proposed investment must not exceed the amount that would be invested by a service provider efficiently minimising costs and must satisfy at least one or more of the following conditions:

   - the investment generates enough revenue to cover the investment costs (the "incremental revenue" condition); or
   - the investment provides a net benefit to justify higher network tariffs (the "net benefits" condition); or
   - the investment is necessary to maintain the safety or reliability of the network or its ability to provide network services (the "safety and reliability" condition).

8. The Authority has reviewed the proposed expenditure of $383.4 million. Generally the proposed expenditure does not exceed the amount that would be invested by a service provider efficiently minimising costs with the exception of $16.7 million (4.4 per cent of the total proposed expenditure) which the Authority considers to be potentially inefficient. Further details on this are set out paragraphs 43 to 83.

9. The Authority has significant concerns in relation to the second part of the new facilities investment test. Western Power has estimated the net present value of incremental revenue over the next 40 years will amount to $206 million and the net present value of other benefits (predominantly linked with an assumed increase in wind generation) will amount to $271 million. Western Power's application therefore claims that the total proposed expenditure of $383.4 million will be met by a combination of incremental revenue and net benefits.

[4] Geoff Brown and Associates 2011, *Technical Review of,* prepared for Economic Regulation Authority of Western Australia

Marsden Jacob Associates 2011, New Facilities Investment Test for Western Power's Mid-West Energy Project (Southern Section), prepared for Economic Regulation Authority of Western Australia

10. Hence, Western Power is proposing that the investment be financed by SWIN customers and is therefore not proposing to require any contributions from specific customers or any other means of financing.

11. However, the Authority is concerned that the counterfactual scenarios chosen for the 'with' and 'without' cases – in order to estimate the benefits – are rather arbitrary. The Authority considers that there are significant uncertainties, and that Western Power has proposed values for benefits towards the higher end of the potential range. An outcome of including the investments in the capital base at this stage would be to transfer the ex-ante risks associated with achieving a return on the new investments – from Western Power to existing customers. The Authority's view is that these risks should be borne by the new loads that would benefit from the new assets, or by Western Power, rather than by existing customers.

12. In its application, Western Power states that the primary driver for the Mid West Energy Project (Southern Section) is to connect the new mining loads and new generating capacity in the Mid West. Without this driver, a much lower cost solution would be adopted to accommodate natural load growth. With this in mind, it is essential that the owners of the major new loads contribute to an appropriate level of those costs, otherwise the benefit they receive will be paid for by all users of the network.

13. The Authority recognises that the proposed augmentation potentially would enable significant new load and generation to be connected to the network which would bring increased revenues to Western Power. However, the majority of the proposed new incremental revenue relates to two new mining operations, one of which has yet to achieve Final Investment Decision. Given the inherent uncertainties associated with mining investment, the Authority is concerned that existing customers should not be left exposed to the risk of a project not going ahead, resulting in the forecast incremental revenue not being realised and exposing existing customers to increases in charges. There are also some flaws in Western Power's calculation of incremental revenue which need to be revised. Further discussion on this is included in paragraphs 24 to 42.

14. The Authority also recognises there may be significant potential benefits resulting from the proposed augmentation which could justify an increase in charges to customers. However the Authority considers a number of the net benefits claimed by Western Power (particularly in relation to wind generation) are uncertain and that some of the assumptions used are overly optimistic. Again, the Authority is concerned therefore that existing customers would be exposed to increased charges with no offsetting benefit.

15. After consideration of Western Power's new facilities investment test application and independent advice from GBA and MJA, the Authority's draft determination is that it cannot give pre-approval at this stage for the total proposed expenditure of $383.4 million to be rolled into the regulated capital base as this may lead to existing customers being exposed to an unacceptable risk of increased charges with no commensurate benefit.

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.

17. The Authority notes that satisfaction of the new facilities investment test is not a prerequisite for a service provider to proceed with an investment. Western Power is free to continue with the project and to either obtain contributions from new loads through commercial negotiation, or else to place the investment into a speculative fund. With the speculative fund, as additional loads are connected, Western Power would be eligible to seek approval to include the additional capacity within the capital base, with a retrospective return. In this way, Western Power would bear the risk of future demand eventuating, not existing customers.

REASONS

18. The reasons for this draft determination address the following matters:

- the test of section 6.51A of the Access Code for adding new facilities investment to the capital base;
- the structure and elements of the new facilities investment test under section 6.52 of the Access Code;
- details of Western Power's proposed works; and
- the assessment of the proposed transmission works against the requirements of the test of section 6.51A of the Access Code, including the new facilities investment test under section 6.52 of the Access Code.

Test for adding New Facilities Investment to the Capital Base

19. Section 6.51A of the Access Code establishes a test that must be satisfied for an amount of new facilities investment to be added to the capital base.

> 6.51A New facilities investment may be added to the capital base if:
>
> (a) it satisfies the new facilities investment test; or
>
> (b) the Authority otherwise approves it being adding *[sic]* to the capital base if:
>
> (i) it has been, or is expected to be, the subject of a contribution; and
>
> (ii) it meets the requirements of section 6.52(a); and
>
> (iii) the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

20. Sections 6.71 and 6.72 of the Access Code allow a service provider to seek a determination that either an actual amount, or forecast amount, of new facilities investment meets the test of section 6.51A.

> 6.71 A service provider may at any time apply to the Authority for the Authority to determine whether:
>
> (a) actual new facilities investment made by the service provider meets the test in section 6.51A; or
>
> (b) forecast new facilities investment proposed by the service provider is forecast to meet the test in section 6.51A.
>
> 6.72 If an application is made to the Authority under section 6.71, then subject to section 6.75 the Authority must make and publish a determination (subject to conditions as the Authority may consider appropriate) within a reasonable time.[5]

[5] Section 6.75 of the Access Code indicates that the Authority must make a determination if the actual or forecast amount of new facilities investment is equal to or greater than $15 million (CPI adjusted);

The New Facilities Investment Test

21. Section 6.52 of the Access Code sets out the new facilities investment test.

6.52 New facilities investment satisfies the new facilities investment test if:

(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold - the modified test is satisfied;

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

22. For convenience, the elements of the new facilities investment test are referred to below as the "efficiency test" (section 6.52(a) of the Access Code), "incremental revenue test" (section 6.52(b)(i)A of the Access Code), "net benefits test" (section 6.52(b)(ii) of the Access Code) and "safety and reliability test" (section 6.52(b)(iii) of the Access Code).

23. For the NFIT to be satisfied, the new facilities investment must satisfy the efficiency test and 'one or more' of the incremental revenue test, net benefits test, or safety and reliability test. The practical interpretation of 'one or more' is taken to be that the sum of the benefit values from the incremental revenue test, the net benefits

otherwise the Authority may make a determination. The 2010 CPI adjusted threshold is $17.8 million as stated in the Economic Regulation Authority's Notice on 2010 Consumer Price Index Adjustments, 1 July 2010 *(update for 2011)*.

test or the safety and reliability test needs to exceed the efficient cost of the new assets.[6]

The Authority's key concerns in relation to Western Power's NFIT application

24. The Authority's assessment of Western Power's new facilities investment test (NFIT) application for the MWEP project is detailed in the remainder of this document. The Authority's key concerns are summarised in paragraphs 25 to 42 below.

25. The Authority's principal concerns in relation to Western Power's NFIT application relate to the approach taken to the incremental revenue test and to the net benefits test.[7] In particular, the Authority considers that there are significant uncertainties around these values, but that Western Power has proposed values for benefits towards the higher end of the potential range. This has the effect of transferring the ex-ante risks associated with achieving a return on the new investments from Western Power to existing customers. The Authority's view is that these risks should be borne by the new loads that would benefit from the new assets, or by Western Power, rather than by existing customers.

Incremental revenue test

26. The purpose of the incremental revenue test is to ensure that existing customers would not face higher prices as a result of an augmentation that is undertaken principally to accommodate new customers – except to the extent that the augmentation provides an additional, separate net benefit for the broader electricity market (which may include maintaining the safety and reliability of the existing network).

27. On this basis, the 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*. The use of existing prices in the calculation is important, as it ensures that existing customers are not paying higher prices to support the expansion of the network, simply to service the new load. In other words, existing customers should not be required to subsidise the connection of new loads, where those existing customers do not receive a net overall benefit.

28. However, Western Power has not used existing transmission prices in its incremental revenue estimate. Rather, Western Power has used an estimate of the value of the new transmission assets in order to derive a 'new' transmission nodal price at Three Springs, and applied this price to the new loads. This sets up a circularity, whereby the cost of the new assets is used to develop transmission prices, which in turn are used to justify the cost of the new asset. Accordingly, the

---

[6] For a detailed explanation of the Authority's interpretation of the NFIT, see Economic Regulation Authority 2011, Issues Paper: New Facilities Investment Test Application for Western Power's Mid-West Energy Project (Southern Section), Appendix A.

[7] The Authority's major concern is not with the efficiency test. Overall, the Authority judges that the efficiency test will be met with a few relatively minor adjustments. In other words, the costs proposed by Western Power for the augmentation are considered to be mostly efficient.

Authority's view is that Western Power's approach is flawed and needs to be re-worked.

29. The forecast of the amount of new load likely to connect to the new assets is also important - if the forecast incremental revenue measured at existing prices fails to materialise due to a shortfall in load, potentially network users could incur the costs of the augmentation over and above any actual net benefits. Consequently, it is important that the forecast of incremental revenue is sufficiently robust for reliance to be placed upon it for the purposes of assessing the NFIT.

30. However, Western Power's proposed incremental revenue includes a prospective load that has 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.

Net benefits test

31. The net benefits test is intended to capture any additional benefits that might accrue beyond the incremental revenue – for those who generate, transport and consume electricity on the network. It is important that there is no overlap with the incremental revenue test, to avoid double counting of benefits.

32. In this case, Western Power has estimated additional net benefits associated with:

- lower generation costs associated with increased wind generation on the network, which flow through to consumers as lower prices;
- additional renewable energy certificate revenue associated with the increased wind generation;
- deferral of network augmentations required to service the natural growth of existing loads; and
- reduced transmission losses for existing loads.

33. The bulk of the additional net benefits estimated by Western Power derive from the ability to connect additional wind generation with the Mid-West Energy Project (that is, associated with the first two dot points in the previous paragraph).

34. However, the Authority is concerned that the counterfactual scenarios chosen for the 'with' and 'without' cases – in order to estimate these net benefits – are rather arbitrary. In particular, 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' augmentation scenario. In addition, the assumptions which support the entry of new wind generation – namely in relation to the carbon price, the value of capacity credits, and the amount of adjacent block loads – have high associated uncertainty with regard to future values.

35. This uncertainty implies that greater sensitivity analysis should be conducted by Western Power to determine whether smaller differences in new wind generation might eventuate between the 'with' and 'without' scenarios.

Treatment of shortfalls between the efficient costs and the overall benefits

36. As noted above, to the extent that the efficient costs are covered either by i) incremental revenue at existing transmission prices or ii) other net benefits, then these costs would be approved under the NFIT and may be rolled into the capital base.

37. That said, there is nothing to prevent either Western Power, or new loads for that matter, taking on the risk of investment in additional new assets that are beyond the NFIT value. Should such 'beyond NFIT' risk investment in new network augmentation be undertaken either by new connecting loads or by Western Power, then this is correctly paid for either by:

- the new load customers, as a contribution; or
- by Western Power, and placed in a speculative investment fund.

38. In the case of contributions by the new load customers, those customers should be entitled to a rebate on their contributions if other customers subsequently benefit from the new investment, as provided for in Western Power's Capital Contribution Policy.

39. In the case of speculative investment, Western Power may retrospectively earn a return on the additional speculative investment once the capacity is taken up by prospective new loads and the related expenditure is rolled into the capital base.

40. However, existing customers potentially could still be exposed to higher prices if new mining loads subsequently shut down earlier than forecast. This risk could be mitigated by Western Power requiring new block load customers to sign guarantees over future revenues. Once any incremental load revenue is guaranteed, a matching level of capital expenditure could be included in the capital base.

41. To the extent that forecast incremental revenue is not guaranteed, that portion of capital expenditure would continue to be treated as speculative investment. The Authority understands discussions with KML in relation to the guarantee of future revenues are in progress. It is likely that over the course of the third Access Arrangement (AA3) review, these matters will progress further and can be incorporated in the Authority's decision for AA3.

42. Under this approach, the risks associated with any new investment that does not pass the NFIT would be correctly allocated to those who are most informed to judge those risks, and who are able to manage best the scale of those risks.

Western Power's Pre-Approval Application

Western Power's submission

43. Western Power submits that the total estimated cost for the project (i.e. $383.4 million) satisfies the new facilities investment test and therefore should be included in the regulated capital base with reference tariffs increased accordingly.

44. In applying the new facilities investment test to the project, Western Power has given separate consideration to three elements of the new facilities investment test:

- the "efficiency test" under section 6.52(a) of the Access Code;
- the "incremental revenue test" under section 6.52(b)(i)A of the Access Code; and
- the "net benefits test" under section 6.52(b)(ii) of the Access Code.

45. Western Power has submitted that the total forecast expenditure of $383.4 million meets the "efficiency test" under section 6.52(a) of the Access Code.

46. Western Power has estimated that the net present value of the incremental revenue arising from the proposed augmentation will amount to $206 million over the next 40 years. This comprises $187 million from iron ore mining and $19 million from wind turbine generation. The forecast revenue from iron ore mining includes revenue from an interim supply arrangement with Karara.

47. Western Power estimates that the net present value of other benefits arising from the proposed augmentation amount to $271 million. This comprises $236 million relating to electricity market based benefits, $26 million arising from deferral of other network expenditure and $9 million relating to a reduction in system losses.

48. As the sum of the amounts claimed by Western Power to meet the "incremental revenue test" and the "net benefits test" (i.e. $477 million) is greater than the total cost of $383.4 million, Western Power submits that the total expenditure meets the new facilities investment test.

Proposed Works

49. The proposed new facilities investment includes:

- A new 189 km double circuit 330 kV transmission line between Pinjar and Eneabba substation;
- A 12 km double circuit 330 kV transmission line between Eneabba substation and the future Eneabba Terminal (currently being constructed by Karara Mining Limited);
- A 58 km transmission line between the future Eneabba Terminal and Three Springs (currently being constructed by Karara Mining Limited);
- Upgrading the existing Neerabup to Pinjar line from operating at 132 kV to 330 kV and building a new 330 kV circuit bay at Neerabup; and
- A new 330/132 kV terminal located at Three Springs interconnecting the 132 kV and 330 kV voltage systems to provide support to the Geraldton region (with the electrical construction works, except for the 330 kV line reactor, being constructed by Karara Mining Limited using its mine site construction resources, through a sole source contract).

50. Further details of the project are provided in section 2 of Western Power's new facilities investment test application.

Forecast Cost

51. Western Power indicates a forecast capital cost for the project of $383.4 million. This cost comprises a number of components which are set out in the table below.

Table 1 MWEP components and total cost

Component of Works	Estimated Cost
(1) 189 km 330 kV transmission line between Pinjar and Eneabba substation including upgrading the existing Neerabup to Pinjar line from operating at 132 kV to 330 kV and building a new 330 kV circuit bay at Neerabup	To be delivered by Western Power
(2) 12 km 330 kV transmission line from Eneabba Substation to Eneabba Terminal	Currently being constructed by KML and subject to commercial negotiations between Western Power and KML.
(3) 58 km 330 kV transmission line from Eneabba Terminal to Three Springs	Currently being constructed by KML and subject to commercial negotiations between Western Power and KML.
(4) 330/132 kV Three Springs Terminal	Three Springs terminal electrical works will be contracted to KML, with the remainder of the work to be delivered by Western Power. The building of the terminal is initially being funded by KML.
Total cost of project	**$383.4 million**

Submissions to the Authority

52. Submissions were received from the following parties:[8]

- APA Group
- Crosslands Resources Ltd
- ERM Power Ltd
- Extension Hill Pty Ltd
- Karara Mining Ltd (confidential)
- RPV Developments
- Shire of Perenjori
- Synergy
- Vestas Australian Wind Technology Pty Ltd
- Wind Prospect Pty Ltd.

[8] These submissions are available on the ERA's website: http://www.erawa.com.au/3/1178/48/mid_west_energy_project_southern_section_augmentat.pm

53. Generally, submissions were supportive of Western Power's proposal. Specific issues raised in support of the MWEP project included:

- delay in commitment represents the greatest single risk to cost overruns for this project;
- generation forecasts for the region are too low and potential new generation capacity already is severely constrained by network capability;
- the Western Power analysis of scenarios in its planning report, and the entire NFIT process, places undue emphasis on short term cost deferral solutions, rather than focussing on actual strategic planning to deliver network solutions that will last more than one to five years;
- incremental and net benefits tests are always estimates and by their uncertainty must be conservatively based with appropriate project contingencies included;
- the development of the Mid West will increase off-peak electricity consumption on the SWIN which will enhance the potential for increased penetration of renewable energy generation;
- the development of generation capacity in the Mid West will provide some degree of enhanced reliability through locational diversity;
- the reduction in electricity prices supported by the ACIL Tasman analysis is consistent with the observed market benefits of wind farms and other generators with a zero or near zero fuel cost in many other energy markets around the world;
- additional wind and non-wind generation is likely to connect following the augmentation, and revenue from those prospective connections should be included in the incremental revenue benefit;
- there is large potential for solar power generation on the eastern fringe of the agricultural area on both the Karara and the planned Extension Hill transmission lines, which is likely to lead to large scale solar generator (200 MW) on each of the two lines within five years.

Assessment Against the New Facilities Investment Test

54. The Authority considered Western Power's application under each part of the new facilities investment test as set out below.

Efficiency Test

Western Power's Assessment

55. In its new facilities investment test application, Western Power submits that the total cost of the project meets the efficiency test of section 6.52(a). To substantiate this claim, Western Power submits that it must demonstrate that:

- the most appropriate option has been selected to meet the requirements associated with reasonable forecasts of growth of covered services;
- the design and design standards are appropriate; and
- the delivery (including acquisition) cost of the new facility is efficient.[9]

56. Western Power considers that the choice of network option is linked to the requirements of the regulatory test defined in the Access Code. The Authority approved a regulatory test for the Mid West Project (Southern Section) in February 2011.[10] Given that the proposed new facilities investment included in the new facilities investment test application is materially the same as that described in Western Power's approved regulatory test application, Western Power submits that the new facilities investment proposed in this application represents the option that best satisfies the requirements of section 6.52(a) of the Access Code.

57. With respect to the appropriateness of design and design standards, Western Power has included several documents that relate to the design and design standards for this project. A summary is set out in section 3.2 of Western Power's application and copies of the Design Reports are included in the attachments to Western Power's application.

58. With respect to demonstrating efficient cost delivery, Western Power submits that it uses a suite of approaches in its project delivery portfolio to ensure, on an ongoing basis, an efficient cost is achieved. The following delivery mechanisms are proposed:

    - competitive tender;
    - preferred supplier;
    - Western Power internal resource; and
    - acquired from or contracted to KML.

59. KML is currently constructing the double circuit 330kV transmission line between Eneabba and its mine site at Karara (via Three Springs). KML is also funding the advancement of the Western Power 132/330 kV Three Springs Terminal and undertaking the electrical construction works (except for the 330 kV line reactor).

60. KML will retain ownership of the transmission line between Three Springs and the Karara mine site and this does not form part of Western Power's application. Western Power will supply the Golden Grove mine via a Wheeling Agreement with KML as the existing line section from Three Springs to Koolyoonooka, currently used by Western Power to supply Golden Grove mine, will be demolished.

61. Western Power and KML are in the process of agreeing the commercial arrangements that will apply to enable Western Power to integrate the KML built assets into its network. The new facilities investment test application has been based on the following:[11]

---

9 Western Power, New facilities investment test application, page 15.

10 This decision is available on the ERA's website: http://www.erawa.com.au/3/954/48/mid_west_energy_project_southern_section_augmentat.pm

11 Western Power, New Facilities Investment Test Application, page 18.

- Three Springs terminal electrical works will be contracted to KML, with the price being the lower of actual documented costs KML incur, and the value that Western Power has estimated the costs to be under an efficient contracting methodology. The building of the terminal is initially being funded by KML and Western Power will refund it for the costs which pass the new facilities investment test.
- The transmission line between Eneabba and Three Springs terminal will be acquired at the cost that Western Power estimates the line can be constructed efficiently, based on the actual line route and actual tower suite, which Western Power considers were the efficient decisions at the time of construction.
- The transmission line between Eneabba and the proposed Eneabba Terminal will be acquired from KML at the cost that Western Power proposed to build the line. This cost is the actual cost quoted by Western Power to KML, prior to its decision to build the line itself.
- The forecast costs include interest during construction in relation to the components built by KML based on Karara's forecast construction cash flow profile with interest applied of 8.9 per cent which is based on the nominal cost of debt approved by the Authority for the current access arrangement.[12]

Considerations of the Authority

62. In assessing whether the proposed transmission works meet the efficiency test of section 6.52(a) of the Access Code, the Authority has considered the costs in relation to the assets constructed by Western Power separately from those assets which will be constructed by Karara.

Assets Constructed by Western Power

63. To assess whether the proposed expenditure is efficient, the Authority has given consideration to the choice of project, the design standard and whether the forecast costs for the project were minimised.

Choice of Project

64. On the choice of project, the Authority accepts that satisfaction of the regulatory test is an adequate demonstration that the proposed transmission works represents an efficient choice of project.

Design Standards

65. The Authority's technical adviser considers the design of the Pinjar-Eneabba line and associated substation works to be reasonable and consistent with good industry practice.

66. However, GBA note that Western Power has designed the line for a 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

[12] Western Power, New Facilities Investment Test Application, page 36.

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.

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.

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.

Minimising project costs

69. Based on advice from its technical adviser, the Authority considers Western Power's delivery plan for this part of the project, which is based largely on competitive tendering with in-house resources only used for work on secondary systems and commissioning, should lead to efficient cost outcomes.

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.

[13] Geoff Brown and Associates 2011, New Facilities Investment Test: Mid West Energy Project: Technical Review, prepared for Economic Regulation Authority of Western Australia, page 26.

71. The proposed expenditure is based on July 2010 prices. The Authority's technical adviser has noted that Western Power has not refreshed the project estimates since July 2010. This is not consistent with Western Power's policy of updating costs every six months. There has been considerable movement in exchange rates and commodity prices since the cost estimates were prepared. Western Power considers it is unlikely the overall costs will have changed significantly.

Assets constructed by Karara

72. In the case of the assets being constructed by KML and subsequently sold to Western Power, the Authority has considered the costs which should be included in the regulatory capital base, the timing of when the investment should be added to the regulatory capital base, depreciation of the assets prior to them being acquired by Western Power and interest during construction. These matters are discussed below.

Costs eligible to be included in Western Power's capital base

73. As noted above, Western Power and KML have yet to complete terms of the commercial arrangements that will apply to the Karara Power project. However, Western Power states that there was agreement in principle between Western Power and KML in early 2011 for a delivery model which included the eventual transfer of ownership of the transmission assets to Western Power, at the costs that pass NFIT.

74. In turn, KML has undertaken to fund these early works on the proviso that certain capital costs will be rebated – either via refund provisions or purchase agreements – once the assets are subsequently included in Western Power's regulated asset base (that is, subject to the NFIT determination by the Authority).[14]

75. Both the Eneabba Substation to Eneabba Terminal line works and the Eneabba Terminal to Three Springs Terminal line works will be acquired by Western Power at the costs which are approved under this NFIT. The Authority has no problem with this approach.

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.

---

[14] For example, WP has included $0m in the NFIT for the TST 330kV dedicated KML assets – these are fully funded by KML - presumably are deemed connection assets, but may eventually contribute to other users should they connect to that line.

[15] In particular, it is based on an average span length of 500 metres, consistent with Western Power's standard at the time KML designed the line. Western Power subsequently moved to 600 metre spans for the revised MWEP 330 kV components as being optimal.

77. The Eneabba Substation to Eneabba Terminal line is being constructed by Karara to the Western Power optimised design. Western Power has proposed the cost should be based on Western Power's cost estimate. GBA considers the estimated costs to be reasonable. The Authority therefore considers the NFIT costs for this relatively short (11.6 km) line section to be acceptable.

Timing of addition of investment to the regulatory capital base

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.

79. In addition, revenue from KML prior to this point should not be included in the NFIT tests.

Interest during construction

80. Interest during construction (IDC) for the NFIT costs of the KML constructed assets was calculated by Western Power from KML's forecast construction cash flow profile. Interest was applied at 8.9 per cent, which is the nominal cost of debt approved for Western Power at AA2. The IDC has then been de-escalated to be expressed in July 2010 dollars.[16]

81. Where Western Power constructed the asset, it would not normally receive IDC – rather, it would be allowed to roll expenditure into the regulated capital base as it was completed. This provides a return for the funds expended, thereby covering its costs. However, as the asset is only being included in the capital base on completion of the MWEP, this relief is not available.

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.

Depreciation on assets prior to Western Power purchase

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).

[16] Western Power, New Facilities Investment Test Application, page 36, 40.

Incremental Revenue Test

Western Power's Assessment

84. Western Power has estimated that the net present value of the incremental revenue arising from the proposed augmentation will amount to $206 million over the next 40 years.[17] This comprises $187 million from new iron ore mining loads (including revenue from an interim supply arrangement with KML) and $19 million from wind turbine generation.

New iron ore mining incremental revenue

85. To derive its forecasts of revenue from iron ore mining loads Western Power has carried out a number of economic analyses. Details of this work are set out in section 6.3.3 and Attachment 4 of Western Power's application.

86. The scenario put forward to support the forecast incremental revenue in Western Power's application is largely based on demand from KML's Karara Stage 1 and Asia Iron's Extension Hill Stage 1 magnetite projects.

87. The net present value is incremental revenue from the product of the estimated incremental Contracted Maximum Demand (CMD) and tariff, projected over 40 years from 2010, and discounted at 7.98 per cent.[18] This period was chosen by Western Power to match best the expected useful life of the asset. In this case, 40 years is the expected life of the Extension Hill mine.[19]

88. The estimated CMD utilised by Western Power for the incremental mining load is a *median* estimate derived from a risk based, random walk model. The median CMD is determined by means of Monte Carlo analysis of the potential demand from KML's Karara and Asia Iron's Extension Hill Stage 1 magnetite projects.[20] The risk based model accounts for the probability of the mines being in operation in each of the 40 years of the analysis – by incorporating the real option values of deferral of opening and also of shutdown within the mines operating decision. Key variables included in the model – which have the most influence over whether the relevant mine is open or closed in any particular year – include:[21]

- the initial iron ore price – a long term average value of around A$100 per tonne was taken as the start point at June 2010 for the random walk model, based on an assumed exchange rate of AUD/USD of 1.00;

- operating expenditure – ranging from $30 to $46.7 per tonne; and

[17] Western Power, New Facilities Investment Test Application, page 19.

[18] Western Power, New Facilites Investment Test Application, page 48 and Appendix 2.

[19] While the Karara mine is expected to last 60 years, Western Power chose the shorter period of 40 years as it supported inclusion of both loads in the incremental load analysis.

[20] A high scenario is also analysed, but not adopted for the purposes of the NFIT. The high scenario adds KML Stage 2 to the KML Stage 1 and Extension Hill Stage 1 incorporated in the medium scenario. Note that these scenarios are different to those contributing to the official Western Power Central Load and High Load forecasts for planning purposes.

[21] Western Power, New Facilities Investment Test Application, Attachment 4, page 16.

- initial capital expenditure.

89. The resulting 50th percentile median forecast average annual CMD suggests that both Karara and Extension Hill mines would operate for most of the 40 year timeframe – demanding 120 MW and 110 MW respectively – giving a combined *median* CMD of 230 MW from 2015 to 2040.[22] This demand is used for the incremental revenue calculation.

90. The assumed tariff commences at $125/kW/year and declines to $96/kW/year in July 2010 dollar terms for most of the 40 year period as step changes in CMD occur.[23]

91. Western Power state that the method used to calculate the above assumed tariffs is in accordance with the policy set out in Appendix A of the Approved Access Arrangement 'Price List Information'.[24] That policy relates to price setting for new transmission nodes. Under the policy:

- transmission 'use of system' prices for both entry and exit points are derived using a computer-based analysis tool called T-Price, which draws on historical load flow information;

- in the case of new sites, historical data is not available, so Western Power nominates a transmission 'use of system' (TUOS) price consistent with all the principles based on the best available knowledge of the network parameters, including asset values and expected load flows, assumptions for maximum demand and utilisation at the new connection, and also any other new or forecast connections;

- the nominated nodal TUOS price is then adjusted annually in line with the average TUOS price adjustment for all transmission nodes;

- where another user subsequently connects to the new connection point, the price that will apply will be the price applying to that connection point at the time;

- the common service metering and control system prices that apply are the standard published prices;

- transmission connection prices are treated as per the connections policy.

92. In line with this methodology in paragraph 91, Western Power developed a new TUOS tariff for the incremental revenue test. The approach draws on estimates of the cost of the new assets and the expected quantity of new loads to be serviced, so as to determine the new tariff.

93. The resulting new tariff is multiplied by the estimated 50th percentile median load, to determine a median incremental revenue.

---

[22] In 2013 - 2014 and 2041 - 2043 only Karara is in operation.

[23] Western Power, New Facilities Investment Test Application, page 48.

[24] Western Power, New Facilities Investment Test Application, Attachment 4, page 49.

94. The resulting 50th percentile median incremental revenue is 2010 $187 million derived from the net present value of the incremental revenues over 40 years discounted at 7.98 per cent.[25] This is the figure presented for the NFIT.

Generator incremental revenue

95. Western Power states that the forecast revenue from wind turbine generation is based on an additional 230 MW of new wind turbine generation which will be connected as a result of the proposed augmentation. The forecast increase in generation is based on a report prepared by ACIL Tasman and the additional revenue has been forecast over a 25 year period with the net present value calculated using a discount factor of 7.98 per cent.[26] It has been assumed that connecting generation pays 20 per cent of the new TUOS tariff that is applied to loads.

96. However, the supporting calculations for the incremental revenue forecast appear to be based on a lower demand figure of 130 MW.

Other load growth

97. Western Power notes that it has excluded natural load growth from its forecasts of incremental revenue on the basis that it is not a primary source of revenue growth for the Mid West Energy Project (Southern Section) and, in the absence of the step-change in demand, would probably be captured via alternative network reinforcement options. The forecast incremental revenue also excludes loads further to the north which would require reinforcement that is additional to the Mid West Energy Project (Southern Section).

Interim supply revenue from Karara

98. The incremental revenue proposed by Western Power includes the interim supply revenue from Karara.

Incremental Costs

99. Western Power has estimated incremental annual operating costs by applying a standard percentage of 2.1 per cent to capital expenditure. However the percentage has been not been applied to the total proposed expenditure of $383.4 million as Western Power has deducted the capital expenditure it considers to be covered by net benefits (i.e. $271 million – see the section on the net benefits below) before applying the standard percentage. The result is that only $2.35 million per annum has been included as an incremental cost, rather than the full $8.04 million.

Considerations of the Authority

100. The incremental revenue test refers to the test under section 6.52(b)(i)A of the Access Code of whether the "anticipated incremental revenue for the new facility is

[25] Western Power, New Facilities Investment Test Application, page 48 and Attachment 4, page 30.

[26] Western Power, New Facilities Investment Test Application, Attachment 4.

expected to at least recover the new facilities investment". "Anticipated incremental revenue" is defined in the Access Code as:

"anticipated incremental revenue" for a new facility means:

(a) the present value (calculated at the rate of return over a reasonable period) of the increased income from charges (excluding any capital contributions) reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the new facility not been commissioned),

minus

(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),

where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with Chapter 6, which may (but does not have to) be the rate of return most recently approved by the Authority for use in the price control for the covered network under Chapter 6.

101. In previous issues papers and decisions relating to new facilities investment applications the Authority has taken the view that the incremental revenue test may be applied by:

- discounted cash-flow analysis, with the necessary condition for roll-in of new facilities investment into the capital base being that the present value of revenues from current tariffs, that would be paid from time to time by the users of the new facility (with roll-in of the new facilities investment), is equal to or greater than the present value of new facilities investment and additional non-capital costs of the new facility; or
- a discounted weighted average tariff (**DWAT**) analysis, with the necessary condition for roll-in of new facilities investment being that the roll-in of the new facilities investment results in a reduction in the DWAT for the covered network.

102. For either of these forms of analysis, the incremental revenue test should be applied such that:

- the analysis should be undertaken over a period of no longer than the expected economic life of the principal assets of the new facility; and
- the discount rate applied in the analysis may be the rate of return applied in the determination of reference tariffs in either the current access arrangement or proposed revisions to the access arrangement, or may be a rate of return otherwise determined by the Authority to be in accordance with the Code objective and in a manner consistent with Chapter 6 of the Access Code.

103. As noted in paragraphs 24 to 38 above, the result of the incremental revenue test being applied is that existing customers will not face higher prices as a result of augmentations to accommodate new customers (except to the extent that the augmentation provides a net benefit including in relation to safety and reliability).

104. Western Power states that the primary driver for the Mid West Energy Project (Southern Section) is to connect new mining loads and generation in the Mid West. Without this driver, a much lower cost solution would be adopted to accommodate natural load growth. With this in mind, it is essential that the owners of the major new loads contribute to an appropriate level of those costs. Given the inherent uncertainties of mining investment, the Authority is concerned that existing customers should not be left exposed to the risk of those projects not going ahead and incremental revenue not being realised.

105. The Authority recognises there may be significant potential benefits resulting from the proposed augmentation which could justify an increase in charges to customers. This is discussed in the next section. The Authority also recognises that, provided the proposed mines come into operation, there will be a significant increase in revenue to Western Power.

106. However, the Authority considers the methodology Western Power has used to calculate incremental revenue potentially results in existing customers being exposed to large price increases. As discussed at paragraph 28 above, the Authority is concerned that Western Power's use of new asset pricing for the TUOS tariffs deviates from the requirement that the incremental revenue test be based on existing prices. The implications of this concern are discussed in more detail in the next section.

Prices used in the incremental revenue test

107. The Authority has previously received and assessed a number of new facilities investment test applications from Western Power which included a calculation of incremental revenue.[27] In each case Western Power used the first methodology noted in paragraph 101 and based the calculation on an existing tariff. For instances where a substation was yet to be built, the transmission nodal price was based on nearest representative TUOS tariffs (for example, the Binningup NFIT was based on nearest substation with a published price, while the NFIT for the Collgar wind farm was derived from an average of the two nearest substations).

108. However, in its current application for the Mid West Energy Project (Southern Section), Western Power used a significantly different methodology to derive the transmission nodal price. As outlined above, Western Power has based incremental revenue on forecast prices which include the capital expenditure relating to the proposed augmentation. As noted in paragraph 90, Western Power has derived tariffs of between $125 and $96 per kW per year depending on what load is assumed. These tariffs are significantly higher than the existing tariff for Eneabba of $74 or for Three Springs of $67.

109. Accordingly, the Authority considers that Western Power should re-work the incremental revenue test to account for the existing tariffs from the nearest node that would apply to the identified loads – were they to be connected to the existing network.

110. Alternatively Western Power could follow the second approach in paragraph 101. The test would then be whether the DWAT resulting from rolling in the new capital investment with the increase in demand is less than the current DWAT.

[27] Binningup Desalination Plant etc

111. Based on the information the Authority has, it anticipates that the DWAT resulting from rolling in the new capital investment will be significantly greater than the current DWAT, which indicates that including the proposed capital expenditure in the capital base will result in an increase in charges to existing customers.

Western Power's estimate of CMD

112. The Authority considers that Western Power's probabilistic model to estimate potential future demand is a valid approach for its internal business decision making. However, the Authority is concerned that the use of a probabilistic model for the purposes of the NFIT provides a mechanism for the transfer of risk from Western Power to existing customers. As discussed in paragraphs 24 to 42 above, the Authority does not consider that such a transfer should be approved under the NFIT.

113. Accordingly, the Authority considers that only CMD block loads that have reached Final Investment Decision (FID) should be allowable for the purposes of this incremental revenue test. This approach would limit the CMD for the test to the block load associated with Stage 1 of the Karara magnetite mine. This would also preclude a portion of the wind turbine loads as these are dependent on adjacent major block loads for overnight demand.

Other matters

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.

115. Interim supply revenue from KML should not be included. As noted above, the interim supply revenue from use of the new assets by KML prior to the commissioning of the MWEP relate to commercial arrangements between Western Power and KML, that are more properly interpreted as interim connection assets. On this basis, the Authority considers that this revenue should not be included in the incremental revenue calculation.

Net Benefits Test

Western Power's Assessment

116. The net benefits test refers to the test under section 6.52(b)(ii) of the Access Code to determine whether the 'new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs'. Under the Access Code, 'net benefit' is limited to net benefits accruing to those who generate, transport and consume electricity in, as the case may be, the covered network and/or any interconnected system.

117. Western Power proposes that net benefits are likely to arise from four sources:

- reductions in the total cost of energy to consumers;

- changes in the costs and revenue of generation on the SWIN;
- deferral of planned network reinforcements that would need to be implemented to maintain a safe and reliable supply to customers in the Geraldton region if the proposed augmentation was not built; and
- reductions in network losses.

118. Western Power proposes that the present value of the total net benefits arising from the MWEP augmentation amount to $271 million, comprising:

- $149 million in reductions in the total cost of energy to consumers;
- $87 million in net benefits for generators – being the sum of net increases in revenues and net reductions in costs;
- $26 million from the deferral of network reinforcements that would otherwise be required; and
- $9 million from reduced transmission network losses.[28]

Each line item from the table is considered in detail under each following sub-heading.

Net benefits to consumers and generators

119. The estimates of the net benefits for consumers ($149 million) and generators ($87 million) set out in the table above are derived from modelling undertaken by ACIL Tasman.[29]

120. The ACIL Tasman estimates are based on the modelled differences between a scenario 'with' the augmentation and a scenario 'without' the augmentation. The scenario estimates are developed by means of a bottom up model of Western Australia's Wholesale Electricity Market called *PowerMark*. This model in turn is informed by a bottom up model of the national market for renewable energy certificates, called *RECMark*. The ACIL Tasman 'with' and 'without' scenarios both incorporate the following key assumptions:

- high load growth on the SWIN, based on Western Power's 2010 'High' forecast, with annual peak demand and energy aggregated into three regions:

    i) North (north of Eneabba)

    ii) Central (including Kalgoorlie)

    iii) South;

[28] Western Power, New Facilities Investment Test Application, page 20.

[29] The details of the analysis for the scenario adopted are shown on pages 52 to 53 of the ACIL Tasman report included in Attachment 4 of Western Power's application (Western Power, New Facilities Investment Test Application, Attachment 4).

- adoption of carbon pricing consistent with the previous Carbon Pollution Reduction Scheme, providing for a 5 per cent reduction in national emissions by 2020 on 2000 levels;
- fuel costs that include:
  - i) legacy coal costs at around $2/GJ;
  - ii) medium 'new' gas costs at around $9 per GJ delivered;
- assumptions around additional wind generation based on results from ACIL Tasman's *RECMark* model of the previous national Enhanced Renewable Energy Target (ERET) policy:
  - i) the 'with' and 'without MWEP (southern section)' scenarios do not include any new wind farms north of Eneabba that are shown to be viable under ERET (Mumbida, Walkaway 2) – hence these wind farms do not contribute to the net benefits;
  - ii) Collgar is assumed to go ahead even in the absence of the MWEP (southern section), hence this wind farm does not contribute to the net benefits;
  - iii) 230 MW of *additional* new wind is made possible in the Central region by the adoption of the MWEP (southern section) – namely Badgingarra and Nilgen – this is a key difference between the 'with' and 'without' scenarios.

121. The modelling by ACIL Tasman suggests that a primary benefit of the MWEP (southern section) is the ability to connect this additional new wind generation in the Central region, and to reduce the amount of new baseload generation in the North region.

122. The net benefit of $149 million flowing from the reductions in the total cost of energy to consumers reflects overall lower STEM prices in the ACIL Tasman model with the proposed MWEP augmentation, compared to a scenario without the augmentation.[30] These STEM price reduction benefits arise from the additional new wind capacity made possible in the Central region by the augmentation, and also from the reduced requirement for combined cycle gas turbine (CCGT) capacity in the North region. Key drivers underlying this outcome are the assumptions relating to capacity credits, carbon prices and renewable energy certificate prices – which lead to wind being a lower cost generation source in the ACIL Tasman modelling than CCGTs.

123. The net benefits of $87 million captured by generators are based on a number of components:

[30] STEM refers to the Short Term Energy Market which is a market operated by the Independent Market Operator (IMO) each day to facilitate short term energy trading. The STEM exists to allow participants to either sell any excess generation capacity that they have, or purchase extra energy at specified times of the day.

- There is a reduction in STEM revenue for generators of $149 million. This exactly offsets the net benefit to consumers reported above, and hence is simply a transfer from generators to consumers.

- There is a net cost of $227 million to generation due to increases in fixed costs for new entrant plant (both in terms of capital costs and fixed operation and maintenance costs). The higher capital spending stems from the assumed higher set up costs of wind compared to CCGTs. Furthermore, the lower capacity of wind farms requires more MW of wind to be installed on the system.

- There is a net saving of $271 million to generation resulting from the lower variable operating cost of wind compared to CCGT generation.

- There is a projected increase of $192 million in renewable energy certificate revenue flowing to generators on the SWIN, given the ability to connect additional new wind.

- Finally, there is a small change in steam revenue associated with base load cogeneration in the South.[31]

124. ACIL Tasman determined the net benefits over a 20 year period, discounted at an estimated post-tax nominal WACC of 9.96 per cent.

Net benefits from deferral in network augmentation

125. The net present value of the benefits arising from the deferral of planned network reinforcements is estimated by Western Power to amount to $26 million. Further details are set out in sections 6.5.4 and 6.5.5 of Western Power's application.

126. The network deferral benefit is the difference in costs associated with reinforcement to meet the natural load growth needs of Geraldton via:

    - a least cost network solution to meet the natural load growth absent the augmentation; and

    - the least cost network solution involving the 330 kV MWEP (southern section).

127. The $26 million net benefit estimate is derived from augmentation modelling based on Western Power's High load growth scenario.

Net benefits from a reduction in transmission losses

128. The reduction in losses on the line north was calculated by Western Power. Western Power developed a load flow case modelling the average daily load in 2010. This load flow case was then projected forward consistent with Western Power's High scenario, and adjusted to develop load flow scenarios 'with' and 'without' the MWEP (southern section). An annual value of the reduction in losses was then estimated from the difference – utilising an average of 2008 to 2011 daily

[31] Steam from cogeneration is sold to alumina production.

energy costs on the SWIN from IMO STEM data ($35.84/MWh). These annual values are then used to determine a net present value, utilising a real discount rate of 7.98 per cent.

129. The net benefit elements detailed in paragraphs 118 to 128 above are summarised in the following table.

Table 2 Western Power's estimates of net benefits

Benefit		**Net Present Value**
Reductions in total cost of energy to consumers	$149	
Net benefits to consumers		$149 million
Reduction in revenue to generators	($149)	
Fixed Costs for new entrant plant	($227)	
Change in variable costs for all plant	$271	
REC revenue	$192	
Steam revenue	$1	
Net benefit to generators		$87 million
Deferral of planned network reinforcements that would need to be implemented to maintain a safe and reliable supply to customers if the proposed augmentation was not built		$26 million
Reduction in network losses		$9 million
Total Benefits		**$271 million**

Considerations of the Authority

130. As noted in section 2.3 above, if the forecast benefits fail to materialise, potentially network users will incur the costs of the augmentation without an offsetting benefit. Consequently, it is important that forecasts of benefits are sufficiently robust for reliance to be placed upon them for the purposes of assessing the new facilities investment test and justifying the approval of higher reference tariffs.

Net benefits for electricity market participants

131. The Authority has a number of concerns in relation to the ACIL Tasman analysis. The first relates to whether the assumptions underpinning the ACIL Tasman analysis are robust, given the significant recent changes in the economic and policy environment. The second relates to assumptions around the ability or otherwise to connect new wind generation. The third relates to the potential for an overestimate in the benefits of increased wind generation capacity. The fourth relates to the structure of the ACIL Tasman model, and whether the estimated benefits for reductions in STEM prices would actually be realised in practice. Each of these concerns is discussed below.

Robustness of the ACIL Tasman assumptions

132. The ACIL Tasman analysis was conducted during the early part of 2010, and completed in June 2010. Key changes that might have material impact on the estimates include revisions to:

- the Commonwealth Government's renewable energy schemes;
- the Commonwealth Government's carbon pricing scheme;
- the WEM rules relating to capacity credits for wind generation;
- the scenario for load growth; and
- estimated generation costs.

133. The Commonwealth's renewable energy scheme has changed from the Enhanced Renewable Energy Target (ERET) adopted for ACIL Tasman's report, to now encompass a small-scale renewable energy scheme (SRES) and a large-scale renewable energy target (LRET).[32] In the ACIL Tasman modelling, new wind was supported under the ERET through a Renewable Energy Certificate (REC) price. 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.[33] 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.[34] This change is material and the value of the identified net benefits needs to be revised by Western Power to reflect this.

134. The Commonwealth's approach to carbon pricing has changed from the arrangements under the Carbon Pollution Reduction Scheme (CPRS) for a 5 per cent reduction in emissions by 2020 on 2000 levels – which was assumed by ACIL Tasman in its modelling for Western Power. 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 tCO_2e under the CPRS to \$29 per tCO_2e under the CEF.[35]

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

---

[32] The SRES provides support for domestic photovoltaic and solar hot water installations, while the LRET supports large-scale renewable energy generation projects including wind.

[33] MJA noted that ACIL Tasman estimates of REC prices differ from MMA's. However, MJA concluded that ACIL Tasman's estimates were plausible and defensible for the purposes of the NFIT.

[34] This reduction is derived from on a difference in the price of LGCs compared to RECs. ACIL Tasman have informed Western Power that this difference is small – at between \$2.00 to \$3.00 per certificate (Western Power, New Facilities Investment Test Application, Attachment 4).

[35] Both estimates are derived from the Commonwealth Treasury's estimates of carbon pricing under the two schemes (Department of the Treasury 2009, Australia's Low Pollution Future: The Economics of Climate Change Mitigation, www.climatechange.com.au; Department of the Treasury 2011, Securing a Clean Energy Future: The Australian Government's Climate Change Plan, www.climatechange.com.au).

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.[36] It is likely that the proposed rule, which has yet to be adopted, would result in significantly lower capacity credits for intermittent generation. (For example, wind generation in the National Electricity Market is assumed to receive 5 per cent of their name plate capacity for reliability planning purposes.)

136. While there have been changes to generation costs, these are likely to be marginal. The Authority is satisfied that any changes would not change materially the wholesale energy prices utilised for the calculation of the net benefits, or significantly change the overall value of the identified net benefits.

137. Overall, the Authority considers that there is significant uncertainty surrounding the elements supporting increased wind generation – relating to carbon prices, capacity credits, and the availability of block loads.[37] The Authority considers that additional sensitivity analysis would be helpful to determine whether the net benefits are highly dependent on outcomes for these elements.[38]

Choice of counterfactual scenarios

138. A large proportion of the estimated net benefits of the MWEP (southern section) is derived from the ability to connect 230 MW of additional new wind generation in the Central region. However, the case for the choice of counterfactual scenarios on which this estimate is derived is not well supported.

139. First, ACIL Tasman assumes that there is no new wind generation north of Eneabba, or in the South region for that matter, in either the 'with' or 'without' scenario. However, if wind generation is the least cost new entry by a significant margin, then it is surprising that there is not more new wind generation in the 'without scenario' – even if not in the Central region. For example, wind generation may be supported by new block loads in the south-west of the State.

140. Second, 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 that these assumptions are at the more optimistic end of the confidence interval. The MJA view is that 'without an explicit rationale for the use of the high growth rate... it [is] appropriate to utilise the medium growth case' for the net benefits analysis.[39] 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.

---

[36] Independent Market Operator 2010, Wholesale Electricity Market Rule Change Proposal No. RC_2010_25, www.imowa.com.au.

[37] Block loads are important to support dispatch of wind overnight. In this context, Western Power have indicated that the new block loads in the Mid-West have an important role in supporting additional wind generation capacity in the Central region.

[38] The Authority notes that ACIL Tasman undertook sensitivity analysis of reduced capacity credit allowance (40 per cent of wind farm capacity down to 20 per cent) and increased load following costs for wind (from $10 per kWh to $15/kWh) which suggested that wind benefits would still be substantial. However, ACIL Tasman did not step in a sensitivity assumption of reduced carbon prices.

[39] MJA 2011, p 17.

141. On this basis, the Authority considers that Western Power needs to provide more information supporting the choice of scenarios adopted for the ACIL Tasman modelling.

Benefits associated with transmission connection

142. The incremental revenue analysis provided by Western Power included incremental revenue of $19 million for the new Central region wind generators' payment of transmission use of system charges. However, as this is a cost to new wind generators, it is in effect a transfer from generators to the network, rather than a net benefit. As it has been counted as a benefit under the incremental revenue test, the corresponding costs should be included in the net benefits component of the NFIT.

143. However, it would appear that ACIL Tasman does not include variable transmission use of system charges in its variable operation and maintenance costs for the additional Central region wind generation (although the capital charges per kW appear to include a component for fixed connection costs). Hence there would appear to be an overstatement of the net benefits – to the extent that these costs are not included.

144. The Authority seeks clarification of these elements from Western Power.

Estimated benefits for consumers

145. Lower energy costs within the WEM lead to an estimated transfer from generators to consumers of $149 million. While this transfer does not influence the overall net benefits, it does suggest that there is a considerable net benefit for electricity consumers from the adoption of the MWEP (southern section).

146. However, the Authority notes that this transfer to electricity consumers is likely to be overstated. This is because ACIL Tasman *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.

147. That said, the Authority recognises that electricity prices for bilateral contracts are likely to converge with STEM prices over time – as contracts roll over. This implies that the overestimate in net benefits for consumers from reductions in electricity prices is likely to be most pronounced in the early years of the estimation period. Given that discounting gives greater weight to near term values, the overstatement in net present values is likely to be significant.

Net benefits from deferral in network augmentation

148. The network deferral benefit of $26 million is the difference in costs associated with reinforcement via:

- 'without' the MWEP – a least cost network solution to meet the natural load growth needs of Geraldton – net present cost of $190 million; and
- 'with' the MWEP – the least cost network solution involving the 330 kV MWEP (southern section) – net present cost of $164 million.

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.

Net benefits from a reduction in transmission losses

150. The reduced costs of transmission losses are likely to accrue either to generators or energy consumers. However, for the purposes of the net benefits test, it does not matter where these benefits go, provided that they accrue to those who ‘generate, transport and consume electricity’.[41]

151. The Authority accepts the underlying approach to estimating transmission losses. The Authority notes that the future value of the transmission loss reduction is uncertain, but that any variance is likely to be small in terms of the overall NFIT. On this basis, the Authority accepts that the amount estimated provides a reasonable estimate for this component of net benefits.

Safety and Reliability Test

Western Power’s Assessment

152. The safety and reliability test is the test under section 6.52(b)(iii) of the Access Code of whether “the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services”.

153. Western Power submits that the primary driver for the Mid West Energy Project (Southern Section) is to connect the new mining loads and generation in the Mid West. Without this driver, Western Power would not require the proposed augmentation to maintain network safety and reliability. The proposed augmentation does allow Western Power to defer other augmentations that would be required for safety and reliability of supply to the Geraldton region. Western Power notes that it has captured this benefit under the net benefits test evaluation and consequently has not relied on the safety and reliability test in its application.[42]

Considerations of the Authority

154. As Western Power does not rely on the safety and reliability test to demonstrate that an amount of the total forecast cost of the proposed works satisfies section 6.52(b) of the new facilities investment test, and in light of no public submissions, the Authority did not consider this matter.

---

[40] Specifically, the report referenced in Attachment 2 of the New Facilities Investment Test Application is Western Power 2010, Planning Report: North Country: Transmission System Reinforcement.

[41] Government of Western Australia, Electricity Networks Access Code 2004, Section 6.52 (b) (ii).

[42] Western Power, New Facilities Investment Test Application, page 20.

The way forward

155. The Authority considers that the information presented by Western Power, to support its new facilities investment test application, does not allow it to give pre-approval at this stage for the proposed total expenditure of $383.4 million to be rolled into the regulated capital base. The Authority's view is that to do so could lead to existing customers being exposed to an unacceptable risk of increased charges, with potentially no commensurate benefit.

156. In summary, the Authority seeks:

- 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.