Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network

Submitted by Western Power

5 September 2012

Economic Regulation Authority
WESTERN AUSTRALIA

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Contents

List of Tables

List of Figures

FINAL DECISION

Background and summary

1. On 30 September 2011, Western Power submitted proposed revisions to its access arrangement for the Western Power Network (**proposed revisions**)[1] to the Economic Regulation Authority (**Authority**). The proposed revised access arrangement relates to the third access arrangement period, the five year period from 1 July 2012 to 30 June 2017. The proposed revisions were submitted in accordance with the requirements of section 4.48 of the *Electricity Networks Access Code 2004* (**Access Code**) and the revisions submission date specified in the current access arrangement.[2]

2. The Final Decision of the Authority is to not approve the revised proposed revisions to the access arrangement.

3. The role of the Authority is to determine whether Western Power's proposed revisions:

   - meet the Access Code objective of promoting economically efficient investment in, and operation and use of, electricity networks and services of networks in Western Australia, in order to promote competition in markets upstream and downstream of the networks; and
   - comply with the requirements of the Access Code.

4. On 29 March 2012, the Authority issued a Draft Decision in accordance with the requirements of sections 4.52 and 4.12 of the Access Code.[3] The Draft Decision of the Authority was to not approve the proposed revisions on the grounds that they did not satisfy the requirements of the Access Code. In its reasons for the Draft Decision, the Authority provided details of 80 amendments required to the proposed revisions before the Authority would approve them.

5. At the time of issuing its Draft Decision, the Authority invited submissions from interested parties on the Draft Decision, with a requirement to lodge submissions by 1 May 2012. On 27 April 2012, the Authority issued a notice extending the deadline for submissions to 29 May 2012.

6. Submissions on the Draft Decision were received from the following parties:

   - Alinta Energy
   - Citelum Australia
   - Department of Finance
   - Energy Made Clean

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1 Western Power, 30 September 2011. *Proposed revisions to the Access Arrangement for the Western Power network*; hereafter cited as ("Proposed Revised Access Arrangement").

Western Power, 30 September 2011. *Access Arrangement Information for 1 July 2012 to 30 June 2017*; hereafter cited as ("Revised Access Arrangement Information").

2 The revisions submission date is specified under the current access arrangement as 1 October 2011 (Western Power, 24 December 2009. *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, clause 1.5, p. 1).

3 Economic Regulation Authority, 29 March 2012, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network.

- Energy Networks Association
- ERM Power Limited
- Grid Australia
- Griffin Power Pty Ltd
- Horizon Power
- Landfill Gas and Power
- Main Roads Western Australia
- Shire of Ravensthorpe
- Synergy
- Urban Development Institute of Australia
- WACOSS
- WA Major Energy Users
- Western Australian Farmers Federation
- Western Power.

7. Western Power's submission to the Draft Decision included revised proposed revisions to the access arrangement as permitted under section 4.16 of the Access Code. Western Power also submitted amended access arrangement information.

8. Under sections 4.52 and 4.17 of the Access Code, the Authority is required to consider any submissions made on the Draft Decision and to issue a Final Decision that either:

    - approves the proposed access arrangement revisions; or
    - does not approve the proposed access arrangement revisions, in which case the Authority must provide details of the amendments required before the Authority will approve the revisions.

9. Western Power's current access arrangement applies until a revised access arrangement is approved by the Authority.

Western Power's Revised Proposal

10. In its reasons for the Draft Decision, the Authority provided details of 80 amendments required to the proposed revisions before the Authority would approve them.

11. In its submission to the Draft Decision, Western Power indicated that it had accepted 35 of the Authority's revisions exactly as required and had modified its revised proposed revisions to the access arrangement to address a further 15 required amendments.

12. Western Power did not accept the remaining 30 required amendments on the grounds that it considered that accepting these amendments would not promote efficient investment in, maintenance, operation and use of the network. Western Power has provided further information which it considers demonstrates that its proposed revisions satisfy the relevant provisions of the Access Code for the Authority's consideration.

13. Western Power's initial proposed revisions to the access arrangement included substantial real increases in average network charges in the first year of the third access arrangement period of 16.4 per cent followed by increases of approximately 11 per cent for the following years.

14. In response to the Authority's Draft Decision (which would result in annual real reductions in average electricity network charges of 0.4 per cent), Western Power's revised proposal includes annual real increases in reference tariffs of 10.3 per cent.

15. The proposed increases in reference tariffs result mainly from the following factors.

- Accelerated recovery of revenue that was deferred in the second access arrangement, due to a change in the treatment of capital contributions, to minimise price shocks. Western Power initially sought to recover the full amount $967 million (dollars at 30 June 2012) during the third access arrangement. Western Power has modified its proposal in response to the Draft Decision and is now proposing to recover the full amount over two access arrangement periods, which has reduced the amount recovered in the third access arrangement to $516.7 million (dollars at 30 June 2012).
- A substantial increase in operating expenditure in real terms over the third access arrangement period. Initially Western Power sought to increase the forecast level of operating expenditure in 2016/17 (the final year of the third access arrangement period) by around 39 per cent compared to the actual level in 2010/11. Following the Draft Decision, Western Power has revised this to an increase of 33 per cent.
- An expanded capital expenditure program. Initially Western Power proposed a capital expenditure program of $5.8 billion compared with $4.3 billion expenditure incurred during the preceding five year period. Following the Draft Decision, Western Power has increased its proposed program to $6 billion.
- The inclusion of capital expenditure previously disallowed as inefficient. Initially Western Power proposed to include $244.4 million of capital investment into the capital base that the Authority had previously disallowed as inefficient expenditure. Following the Draft Decision, Western Power has reduced its claim to $111.5 million.
- An increase in the rate of return. Initially Western Power sought a real pre-tax rate of return of 8.82 per cent compared with the current access arrangement real pre-tax return of 7.98 per cent. Following the Draft Decision, Western Power has proposed a real post-tax return of 6.39 per cent. This is equivalent to a real pre-tax return of 7.65 per cent.

Summary of Key Points

16. Paragraphs 17 to 80 summarise some of the key points included in the Authority's final decision. This summary is not a comprehensive statement of the Authority's reasoning. The Authority's full reasoning for its final decision is set out in paragraph 81 onwards.

17. In making its assessment of Western Power's forecast target revenue requirement, the Authority has had regard to:

- Western Power's performance during the first access arrangement (2006/07 to 2008/09) and second access arrangement (2009/10 to 2011/12) periods:

  - significant under expenditure during the second access arrangement period compared with the forecast costs approved by the Authority in its final decision in relation to the second access arrangement period;
  - good service standard performance during the second access arrangement period; and
  - notwithstanding the improvements that have been made during the second access arrangement period, the ongoing deficiencies in relation to Western Power's management and governance processes for undertaking operating and capital activities.
- Significant increases in Western Power's expenditure forecast for the third access arrangement period compared with actual expenditure during the second access arrangement period.
- Western Power's management of its wood poles:
  - an outstanding Energy Safety Order in relation to the condition of Western Power's wood poles;
  - the 2011 Asset System Review[4], which identified issues with Western Power's asset information; and
  - a recent Parliamentary inquiry into Western Power's management of wood poles which has highlighted serious weaknesses in Western Power's asset management procedures including its management of asset data.
- Efficiency of operating expenditure:
  - a comparison of Western Power's costs with other network service providers.
- Proposed methodological changes by Western Power compared with previous access arrangements all resulting in an increase to forecast target revenue.

Western Power's performance

18. Western Power's total capital expenditure during the second access arrangement is estimated to be 40 per cent ($1.3 billion) lower than the $3.1 billion approved by the Authority. The major areas of under expenditure have been capacity expansion and customer driven capital expenditure, particularly on the transmission network. Notwithstanding this, Western Power has met or exceeded 50 of the 57 service level benchmarks during the second access arrangement which has earned it a service incentive reward of $30 million and, over this time, network service levels have shown an improvement from earlier years.

19. While there are a number of reasons for this underspend, including the impact of the global financial crisis on electricity demand and reduced new customer connections, the fact that Western Power still exceeded its service level targets in spite of substantial capital expenditure reductions indicates there was some inefficiency in its approved capital expenditure forecast for the second access arrangement period.

[4] GHD Asset Management System Review Final Report, October 2011.

20. In previous access arrangement reviews the Authority has identified serious weaknesses in relation to Western Power's planning, design and governance of investment expenditure and inefficiencies in cost estimation processes. These findings led to the Authority excluding $261 million ($ real as at 30 June 2009) of capital expenditure incurred in the first access arrangement period from Western Power's capital base.

21. Western Power notes in its proposed revised access arrangement that, in response to the criticism by the Authority and the Authority's technical adviser, it "sharpened" its focus on initiatives to improve strategic planning, delivery and compliance processes.[5] As a result, a number of capital projects included in the forecasts for the second access arrangement period were deferred or cancelled, confirming the Authority's view that Western Power needed to improve its planning processes.

22. The Authority's technical consultant has observed that processes for managing the development and implementation of capital expenditure and operating expenditure projects and programs have improved since the second access arrangement review. However, the Authority's technical consultant notes:

> … some risk management processes are in place (as we would expect) but they are relatively unstructured, and tend to be qualitative and subjective. While risk assessments are required for all capital projects and programs, they appear to be used primarily to support business cases rather than as an integral part of the planning and prioritisation process. We think risk assessments could be better structured and used more effectively as a tool for prioritising expenditure.[6]
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> …
>
> Western Power recognises the deficiencies in its current risk assessment and prioritisation processes and is taking steps to address them. Good industry practice is for asset maintenance and replacement activities to be prioritised across asset classes using a condition based risk management approach. Each asset is given a "health index" based on its condition weighted by a quantitative assessment of the risk to the business should the asset fail. Assets are prioritised for maintenance on the basis of their health indices. Western Power does this for some individual asset classes but has still to extend this approach to directly compare the risk of asset failure across different asset classes.[7]
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> …
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> … further improvements are possible particularly in relation to the development and assessment of alternative options for expenditure projects and programs. In addition, Western Power still lacks a quantitative risk assessment tool and the application of risk management techniques to the prioritisation of expenditure appears unstructured and subjective. Western Power is planning to improve its risk management processes and is purchasing new asset management software. However, the extent to which it is planning to further integrate risk assessment into its expenditure planning processes and to implement a maintenance management system based on condition based risk management principles consistent with industry best practice remains unclear.[8]

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5 Western Power Access Arrangement Information p. 62.

6 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 23.

7 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 23.

8 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 1.

> …
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> Management of data on the existence and condition of assets is a problem for Western Power and this continues to adversely impact the efficiency with which programs and projects are implemented. While some stakeholders appear to see this as a problem of data accuracy, the timeliness with which existing databases are updated and the availability of current asset information to staff managing and implementing field work appears to be a more significant issue. The ongoing reliance on legacy asset information databases with limited functionality and accessibility is part of the problem; these systems are currently being replaced. However, we think insufficient resources are being applied to the updating of asset data and consider that, unless this problem is addressed effectively, Western Power will not fully capture the benefits of its substantial investment in replacement asset information systems and databases. We have also seen little evidence of how Western Power plans to leverage these new information technology (IT) systems to improve the efficiency of its service delivery. We note, in particular, that such efficiency gains have not been allowed for in Western Power's expenditure forecasts.[9]

23. Whilst the Authority notes the improvements in processes identified by its technical consultant, it is concerned there are still areas of weakness, particularly in relation to risk management and asset information. Potentially these weaknesses may lead to inefficient investment decisions.

Capital Expenditure[10]

Capacity Expansion and Customer Driven Expenditure

24. In its advice for the Draft Decision, the Authority's technical adviser identified $465 million in Western Power's initial forecasts for capacity expansion and customer driven expenditure which it considered was potentially overstated. The reasons for this included:

    - specific projects which could be deferred;
    - inefficiencies in specific projects;
    - forecast increases compared to historical levels which were not adequately supported; and
    - reductions in the demand forecast since the expenditure forecasts were prepared which would enable capacity expansion projects to be deferred.

25. Capacity expansion and customer driven capital expenditure, are subject to an investment adjustment mechanism which ensures that Western Power's target revenue is adjusted at the next access arrangement review for any forecasting error in relation to such expenditure. Expenditure higher than forecast can only be recovered to the extent that it is demonstrated to be efficient expenditure.

26. Given that any capacity expansion or customer driven capital expenditure overspend that meets efficiency requirements can be recovered in the fourth access arrangement

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[9] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 1.

[10] The Authority's detailed reasoning in relation to forecast capital expenditure is set out in paragraphs **808** to **1000** of this Final Decision.

period on a net present value (**NPV**) neutral basis[11], and given the significant capital underspend compared to that forecast during the second access arrangement period, the Authority considers it prudent for the approved capital expenditure for the third access arrangement to be conservative. There will therefore be less likelihood that customers will be asked to pay more during the third access arrangement period than needed to fund the actual capital expenditure requirement, and the incentive on Western Power to deliver only an efficient level of capital expenditure is likely to be greater as actual capital expenditure will be subject to more intense ex post scrutiny if it is higher than the forecast approved by the Authority.

27. Consequently, in the Draft Decision, the Authority accepted all the recommendations of its technical consultant and reduced Western Power's capital expenditure forecasts accordingly by $465 million.

28. Following the Draft Decision, Western Power revised its forecasts and provided further information to the Authority. Taking account of this new information and advice from its technical adviser, the Authority has increased forecast investment as follows:

- increased investment for load growth by $5 million;
- included $108 million for Western Power's proposed CBD substation; and
- included $42.6 million for environmental and planning costs.

29. In the Draft Decision, based on advice from its technical adviser, the Authority did not allow Western Power's proposed expenditure for the CBD (Central Business District) substation on the basis that it was not satisfied that the construction of a new substation in the CBD during the third access arrangement period was consistent with the least cost approach to addressing emerging supply issues within the CBD.

30. In response to the Draft Decision, Western Power completely revised its proposal so that it now forms part of a longer term strategy to address emerging issues with the CBD and in particular the ageing 66 kV infrastructure and the operating and capacity problems that would eventually arise if these assets were to be replaced on a like for like basis. The Authority's technical adviser has reviewed the revised proposal and recommends that it be accepted by the Authority. However, the Authority's technical adviser noted that:

> *"We suggested in our Technical Report that the CBD development plan in the Original AAI was sub-optimal and not well developed, and the radically different plan now proposed on the basis of the SKM study confirms this."*[12]

31. Taking account of the advice from its technical adviser, the Authority has increased forecast expenditure by $108 million to include the project.

32. In relation to the planning and environmental costs, the Authority did not include these in its Draft Decision as they did not meet the Access Code requirement for these costs to be included in the capital base (new facilities investment test). Western Power subsequently revised its forecast to remove strategic early planning costs. The

11 NPV neutral means that Western Power will be compensated as if it had foreseen the additional expenditure and the approved revenue included full provision for that investment from the date the expenditure is incurred.

12 Geoff Brown & Associates, Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision, September 2012, p. 46.

Authority has also adjusted Western Power's forecast costs to make them consistent with the load forecasts assumed in the Final Decision.

33. The Authority notes that if Western Power needs to spend more than the approved forecast then, provided it can be demonstrated to be efficient, the additional capital expenditure will be allowed for at the time of the fourth access arrangement review and, in the case of capacity expansion and customer driven expenditure, will leave Western Power NPV neutral. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for explicit pre-determination of whether proposed capital expenditure meets the efficiency requirements of the Access Code.

Wood Poles

34. The poor condition of its wood pole population poses a high risk for Western Power because of the risk to public safety from unassisted wood pole failures and the potential for such failures to start bush fires that cause extensive property damage. Western Power's wood pole failure rate is significantly higher than other Australian distribution network service providers.

35. In September 2009 Western Power was issued with an Order by EnergySafety which required, amongst other things, that all unsupported rural wood poles which do not comply with required standards be replaced or reinforced by 2015.

36. Western Power initially proposed forecast capital expenditure of $748 million to enable it to increase its wood pole replacement and reinforcement rates. Based on its assessment of the condition of the wood pole population, Western Power considered it would take 20 years of elevated investment before it can reach a sustainable rate of replacement.

37. At the time of the Draft Decision, the Authority understood that EnergySafety considered Western Power's proposed wood pole management program was inadequate and that Western Power's preferred investment approach did not fully meet the EnergySafety Order requirements.

38. Western Power's unassisted wood pole failure rate has also been the subject of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament.[13]

39. The report of the Legislative Council's Standing Committee on Public Administration and the asset management review[14] undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program.

40. The Authority's technical adviser considered that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented were available, particularly if Western Power successfully addressed issues related to records management. However, the Authority considered any efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the actual expenditure.

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13 Unassisted Failure: Report 14, Standing Committee on Public Administration, Report 14, Legislative Council, Parliament of Western Australia, January 2012.

14 GHD Asset Management System Review Final Report October 2011.

41. Following the Draft Decision, Western Power has proposed to increase its wood pole investment to what it considers is the greatest extent possible under current delivery constraints. Western Power proposes to reinforce an additional 204,820 wood poles at a cost of $332.5 million and is investigating options to further increase wood pole reinforcements during the third access arrangement period by securing the services of a second service provider. This could result in up to an additional 75,000 reinforcements.

42. In the Draft Decision the Authority recognised that potentially the investment needs for wood pole management may change as Western Power further develops its understanding of what is required. To ensure that Western Power is incentivised to do this in an efficient manner, the Authority decided that, for the third access arrangement period, expenditure relating to wood pole management should be subject to the investment adjustment mechanism. This will then enable expenditure higher than forecast to be recovered, to the extent that it is demonstrated to be efficient expenditure, and will provide Western Power with a return on that investment from the date it is incurred. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts. All of these provisions ensure Western Power is not constrained to only spend what is allowed in the current forecast.

43. For the purposes of the Final Decision, the Authority recognises the need for increased investment to improve Western Power's wood pole management and has increased the capital expenditure forecast for the distribution network approved in the Draft Decision by $364.9 million primarily to incorporate Western Power's proposed increase in wood pole reinforcements. This is in addition to the $748 million previously requested by Western Power in relation to wood pole management which was accepted by the Authority in the Draft Decision. As noted above, efficient investment will be rolled into the capital base at the next access arrangement review.

IT Expenditure

44. Contrary to the overall underspend in capital expenditure during the second access arrangement period, expenditure in relation to information technology was significantly higher than forecast and Western Power proposed further substantial increases in the third access arrangement period. Based on advice from its technical adviser, the Authority does not consider the increases in expenditure have been adequately justified and has reduced the forecast expenditure for the third access arrangement period to be in line with actual expenditure during the second access arrangement period.

Operating expenditure[15]

45. As is the case with capital expenditure, Western Power's operating expenditure during the second access arrangement period has been significantly lower than the forecasts approved by the Authority. Western Power's forecasts (both initial and revised following the Draft Decision) for the third access arrangement period include significant increases above the actual expenditure during the second access arrangement period.

[15] The Authority's detailed reasoning in relation to forecast operating expenditure is set out in paragraphs 245 to 566 of this Final Decision.

46. The Authority has paid particular attention, with the assistance of its technical advisor, to ensuring an efficient level of base operating expenditure and only legitimate increases above that are included in the forecast for the third access arrangement period. The Authority remains of the view that a reduction of $5.8 million from the base year expenditure is required based on a line item review for reasonableness.

47. In the Draft Decision, the Authority's review of operating expenditure, which was assisted by its technical adviser, identified $170.7 million of inefficient forecast expenditure relating to specific items of network costs, indirect costs and corporate costs which have been removed from the operating expenditure forecasts. The Authority has not altered its view in this Final Decision on these costs which it removed from the operating expenditure forecasts. However, small adjustments were made to Western Power's operating expenditure to reflect new items it proposed and were accepted by the Authority, which results in an increase of around $45 million in operating expenditure from the Draft Decision. Most of these costs relate to Western Power's revised wood pole management plan and streetlight switch wire program to address public safety issues.

48. Benchmarking by the Authority's technical consultant in both its reports pre and post the Draft Decision has shown that Western Power's operating expenditure performance is relatively poor compared with its Eastern State counterparts. At a high level this would suggest there is significant opportunity for Western Power to make further efficiency gains. The Authority notes that Western Power's business case for its proposed strategic program of works, which is expected to cost more than $132 million over a period of five years, was justified on the basis that it would lead to efficiency gains. The Authority's technical consultant reviewed Western Power's expected benefits from its proposed strategic program of works and considered that the expected annual operating expenditure efficiency gain will be nearly $37 million in 2016/17 (the last year of the third access arrangement period).

49. As a result, the Authority considers that this gain should be accounted for and has applied an annual compound 2 per cent efficiency factor beginning in 2013/14 to reflect that around $37 million per annum in efficiency gains will be achieved by 2016/17.

Return on Regulated Capital Base[16]

50. Western Power initially proposed a rate of return or weighted average cost of capital (**WACC**) for its regulated capital base of 8.82 per cent (real, pre-tax). This WACC was higher than the real pre-tax WACC of 7.98 per cent approved for the second access arrangement period. In its draft decision, the Authority did not consider the proposed WACC to be consistent with the Code objective, or with prevailing rates for a business of its type, and adjusted the rate of return accordingly.

51. The Authority based its rate of return on an estimate derived utilising the Capital Asset Pricing Model (**CAPM**), with:

- an estimated nominal risk free rate of return derived from prevailing yields for 5 year Commonwealth Government bonds;
- a benchmark capital structure of 60 per cent debt, 40 per cent equity;

[16] The Authority's detailed reasoning in relation to the return on the regulated capital base is set out in paragraphs 1296 to 1841 of this Final Decision.

- an estimate of the debt risk premium based the bond yield approach, for a benchmark sample of Australian corporate bonds with a credit rating of A-;
- a market risk premium (**MRP**) of 6 per cent; and
- an equity beta of 0.65.

52. The Authority in the draft decision also adopted a real post-tax revenue model (**PTRM**), recognising that this approach meets the objectives of the Access Code and is consistent with the practice of nearly all other regulators in Australia. The PTRM estimates the revenue required to cover tax liabilities separately from the revenue required to provide a return on capital.

53. Together, the adoption of the PTRM and the Authority's CAPM estimates resulted in a real *post-tax* WACC of 3.87 per cent in the draft decision.[17]

54. In its response to the draft decision, Western Power accepted the use of the post-tax approach, but not the Authority's CAPM estimates. Western Power proposed a revised real *post-tax* WACC of 6.39 per cent. The difference between Western Power's estimate and the Authority's estimate derived from:

    - the use of risk free rate based on Commonwealth Government bonds with a term of 10 years, not a term of 5 years as required by the Authority;
    - the use of Bloomberg's 7 year BBB bond fair value curve – extrapolated to 10 years – to derive the debt risk premium, rather than use of the Authority's bond yield approach for a sample with 5 year terms;
    - an estimate of the MRP of 7.75 per cent, rather than the 6 per cent adopted by the Authority for the draft decision;
    - the use of an equity beta of 0.8 rather than the Authority's 0.65, on the grounds that this would offset the 'aggressiveness' of other aspects of the Authority's draft decision.

55. The Authority has reviewed and updated its decision in light of Western Power's and other stakeholders' submissions.

56. The Authority remains of the view that the term of the regulatory period supports the use of a term of 5 years for estimating the risk free rate and debt risk premium. The Authority has therefore based the estimate of the risk free rate for this final decision on the yield of 5 year Commonwealth Government bonds.

57. With regard to the benchmark credit rating, the Authority has adopted a debt risk premium based on yields from all Australian corporate bonds with a credit rating of BBB, BBB+ and A-. The Authority remains of the view that the Bloomberg seven year bond fair value curve, and the extrapolation to 10 years, is problematic. The Authority therefore has retained its use of the bond yield approach for estimating the debt risk premium.

58. The Authority considers that its estimates of the historic differences between the Australian equity risk premium and a 5 year term for the nominal risk free rate are reasonable and support a market risk premium of 6 per cent.

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[17] A real *post-tax* WACC of 3.87 per cent is equivalent to a real *pre-tax* WACC of 4.73 per cent.

59. Finally, the Authority considers that Western Power's arguments supporting a higher equity beta cannot be sustained. The Authority has retained an equity beta of 0.65 for the final decision.

60. Giving effect to its reasoning, and updating its estimates for the most recent data for the 20 day trading period until 15 June 2012, the Authority has determined a real post-tax WACC to apply for this final decision of 3.60 per cent.[18]

Methodological changes for assessing target revenue

61. In its initial proposal, Western Power included a number of new modelling methodologies and assumptions. In the Draft Decision, the Authority noted that all of these changes proposed by Western Power resulted in an increase to target revenue. In response to the Draft Decision, Western Power has removed the majority of these changes from its proposal.

Capital expenditure previously disallowed as inefficient[19]

62. As indicated in paragraph 20 the Authority excluded $261 million ($ as at 30 June 2009) of capital expenditure incurred in the first access arrangement period from Western Power's opening capital base for the second access arrangement period. This was as a result of weaknesses the Authority identified in relation to Western Power's planning, design and governance of investment expenditure and inefficiencies in cost estimation processes.

63. Despite the fact that Western Power acknowledged that improvements needed to be made and has since embarked on a process of doing so (see paragraph 21 above), it initially proposed that $240 million of the expenditure disallowed by the Authority should now be included in its capital base. As stated in the Draft Decision, the Authority's view is that any improvements made by Western Power to its processes since the last access arrangement review will not change the findings of the Authority in relation to past expenditure. Consequently, in the Draft Decision the Authority did not agree that the $240 million should be added to Western Power's opening capital base. However, $5 million relating to planning costs for the Mid West Energy Project were taken into account when adjusting Western Power's forecast expenditure to make it consistent with the amount determined to be efficient by the Authority in its final decision on the Mid West Energy Project (Southern Section) new facilities investment test application published in January 2012.

64. In response to the Draft Decision, Western Power reduced its claim to $111.5 million. The Authority has reviewed Western Power's revised claim and maintains its view, as expressed in the Draft Decision, to not allow this expenditure to be rolled into the capital base, other than the amount included for the Mid West Energy Project (Southern Section).

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[18] The Authority's detailed reasoning in relation to the return on the regulated capital base is set out in paragraphs 1296 to 1841 of this Final Decision.

[19] The Authority's detailed reasoning in relation to capital expenditure previously disallowed is set out in paragraphs 698 to 746 of this Final Decision.

Tariff Equalisation Contributions[20]

65. The Authority considers the tariff equalisation contribution (TEC) is not a cost related to the provision of electricity network services to Western Power's customers. However, the Access Code requires that Western Power be able to recover these costs. At the time of the Draft Decision, Western Power had not been required, by a notice made under section 129D(2) of the *Electricity Industry Act 2004* (Act), to pay a TEC into the Tariff Equalisation Fund during the third access arrangement period, so Western Power proposed an estimate of the amount which was $906.9 million over the five years. A TEC was gazetted by the Treasurer on 7 August 2012. The gazetted amount is $735.9 million over the five years which is less than the amount assumed in the Draft Decision. The Authority has estimated the distribution network reference tariffs on the basis of the approved target revenue plus an allowance for the gazetted TEC amount.

Deferred Revenue[21]

66. Western Power initially proposed that the revenue deferred during the second access arrangement[22] should all be recovered during the third access arrangement period. In the Draft Decision, the Authority determined that the deferred revenue should be recovered over a ten year period to avoid price shock to customers. Western Power has accepted this amendment in its revised proposed revisions to the access arrangement.

Incentives

67. Incentive mechanisms to encourage Western Power to provide services to customers at an efficient cost form an important part of the regulatory regime. The incentive framework contained in this Final Decision is designed to ensure Western Power provides services at an efficient cost. The incentive framework includes:

- a Gain Sharing Mechanism – a mechanism to provide a reward for any out-performance of operating expenditure forecasts included in this final decision;
- a Service Standard Adjustment Mechanism – a mechanism designed to reward (or penalise) Western Power for out-performing (under-performing) on its service performance against benchmarks;
- a D-Factor scheme – a mechanism designed to incentivise demand management or network control services where these are more efficient than a network augmentation;
- an assessment of actual capital expenditure incurred at the next access arrangement review to ensure only efficient capital expenditure is included in the capital base; and

20 The Authority's detailed reasoning in relation to Tariff Equalisation Contributions is set out in paragraphs 1835 to1840.

21 The Authority's detailed reasoning in relation to deferred revenue is set out in paragraphs 1798 to 1831 of this Final Decision.

22 A revenue adjustment which resulted from a change in the treatment of both contributed payments and gifted assets that are given to Western Power for the calculation of the allowed regulatory revenue.

- an assessment of the efficient base operating expenditure during the third access arrangement period, and the inclusion of a 2 per cent annual efficiency adjustment in operating expenditure during the third access arrangement period.

68. In the Draft Decision the Authority included a service standard benchmark measuring Western Power's compliance with its Customer Charter with the intention being that such a service standard would address concerns regarding the conduct of Western Power staff and contractors when entering and conducting work on farm land. In making its Final Decision, the Authority recognises a number of practical barriers to this approach. In light of these practical barriers, the Authority encourages Western Power to work with farming bodies to resolve this problem, and notes the dialogue which has been opened, particularly the undertaking to develop a database of land owners that wish to be contacted prior to Western Power entering their land.

69. In the meantime, the Authority will also evaluate a licence condition that requires reporting by Western Power of the number of complaints in relation to land access. Should improvement to acceptable levels of complaint not be forthcoming through voluntary action by Western Power, then the Authority will consider establishing a licence condition, which could be subject to penalties for non-compliance.

Final decision and indicative price impacts

70. The Final Decision of the Authority is to not approve the revised proposed revisions to the access arrangement. The detailed reasons for this final decision are outlined in the following sections of this document.

71. The Authority's final decision results in a forecast target revenue of $6.7 billion for the third access arrangement period which is $3.6 billion (35 per cent) below Western Power's initial proposed forecast and $2.4 billion (26 per cent) below its revised proposed forecast. This target revenue results in overall average charges remaining broadly constant in real terms over the third access arrangement period, compared with Western Power's proposed real increases of 10.3 per cent per year.[23]

72. Network charges make up approximately 40 per cent of current electricity tariffs for residential customers.

73. Total forecast revenue has decreased from the draft decision reflecting a reduction in the return on assets due to changes in market conditions since the Draft Decision and a reduction in the TEC, offset by higher expenditure forecasts as discussed above. The Final Decision forecast change in prices is based on updated load information submitted by Western Power in its revised proposal in May 2012 in relation to volumes. For the purposes of the Final Decision it is assumed that the revised tariffs will first come into effect on 1 January 2013 which also affects the forecast change in prices.

74. The main differences between the Authority's final decision and Western Power's revised proposal relate to a reduced rate of return/WACC and a lower allowance for capital and operating expenditure. These differences are summarised in Table 1 below.

[23] Based on Western Power's forecast volumes and excluding any adjustments for under or over recovery of revenue in previous years.

Table 1 Comparison of Western Power proposal and Authority's Decision

	Western Power Proposal	ERA Draft Decision	Western Power Revised Proposal	ERA Final Decision
Target reference service revenue (real)	$10.3 billion	$6.9 billion	$9.1 billion	$6.7 billion
Capital Expenditure previously disallowed as inefficient (real)	$244 million	$0 million	$111.5 million	$5.1 million[24]
WACC (real post-tax)	8.82%[25]	3.87%	6.39%	3.60%
Opening Capital Base for AA3 (real)	$7.1billion	$6.5 billion	$6.6 billion	$6.4 billion
Forecast Opening Capital Base for AA4 (real)	$10.4 billion	$9.0 billion	$10.1 billion	$9.4 billion
Capital Expenditure (real)	$5.1 billion	$4.1 billion	$5.2 billion	$4.7 billion
Operating Expenditure (real)	$2.7 billion	$2.2 billion	$2.7 billion	$2.3 billion
Deferred revenue recovered (real)	$967.2 million	$463.1 million	$516.7 million	$406 million
Forecast average network tariff change on 1 July 2012[26]	CPI + 16.4%	CPI - 1.0%	CPI + 8.2%	CPI – 0.7%
Forecast average network tariff change on 1 July 2013	CPI + 11.1%	CPI - 0.7%	CPI + 10%	CPI – 0.3%
Forecast average network tariff change on 1 July 2014	CPI + 11.2%	CPI - 0.4%	CPI + 11%	CPI + 0.1%
Forecast average network tariff change on 1 July 2015	CPI + 11.4%	CPI - 0.1%	CPI + 11.1%	CPI + 0.5%
Forecast average network tariff change on 1 July 2016	CPI + 11.5%	CPI + 0.2%	CPI + 11.1%	CPI + 0.8%

75. The Authority also requires a number of amendments to be made to the access arrangement including:

- revisions to the proposed service standard benchmarks and service standard adjustment mechanism to include a number of existing measures Western Power was proposing to remove and to ensure the proposed benchmarks reflect current levels of service;
- revisions to the proposed revised applications and queuing policy to take account of issues raised by interested parties, particularly in relation to the operation of the competing applications groups.

76. Each of the required amendments is discussed in the relevant sections of the final decision.

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[24] This relates to planning costs incurred on the Mid West Energy Project incurred in the first access arrangement period. These costs were included in the Authority's Draft Decision but were treated as an adjustment to the opening capital base and not shown separately.

[25] Western Power's initial proposal was a pre-tax WACC of 8.82 per cent.

[26] Final Decision forecast average changes assumes new tariffs take effect from 1 January 2013.

77. The amendments that are required to be made to the revised proposed access arrangement revisions before the Authority will approve them are listed in Appendix 1. For the purposes of clarity, the required amendments are also indicated in the reasons for this Final Decision at the point at which each relevant element of the proposed access arrangement revision is considered.

78. Under sections 4.52 and 4.19 of the Access Code, Western Power may submit amended proposed access arrangement revisions to the Authority within 20 business days of this Final Decision.

79. As the Authority's Final Decision is to not approve Western Power's revised proposed access arrangement revisions, the Authority will issue a further final decision as required under sections 4.52 and 4.21 of the Access Code. The Authority's further final decision may:

- if amended proposed access arrangement revisions are submitted by Western Power, approve or not approve the amended proposed access arrangement revisions; or
- if no amended proposed access arrangement revisions are submitted by Western Power, either approve or not approve the proposed access arrangement revisions that are the subject of this Final Decision.

80. In the event that the further final decision of the Authority is to not approve either amended proposed access arrangement revisions or the revised proposed access arrangement revisions, the Authority will proceed to draft and approve its own access arrangement revisions in accordance with the provisions of section 4.52, 4.24 and 4.25 of the Access Code.

CONTENT OF AN ACCESS ARRANGEMENT

81. The required content of an access arrangement is specified in Chapter 5 of the Access Code. Section 5.1 of the Access Code requires that an access arrangement:

- specify one or more reference services under section 5.2 of the Access Code;
- include a standard access contract under sections 5.3 to 5.5 of the Access Code for each reference service;
- include service standard benchmarks under section 5.6 of the Access Code for each reference service;
- include price control under Chapter 6 of the Access Code;
- include pricing methods under Chapter 7 of the Access Code;
- include a current price list under Chapter 8 of the Access Code and a description of the pricing years for the access arrangement;
- include an applications and queuing policy under sections 5.7 to 5.11 of the Access Code;
- include a contributions policy under sections 5.12 to 5.17D of the Access Code;
- include a transfer and relocation policy under sections 5.18 to 5.24 of the Access Code;
- if required under section 5.25 of the Access Code, include efficiency and innovation benchmarks under section 5.26 of the Access Code;
- include provisions dealing with supplementary matters under sections 5.27 and 5.28 of the Access Code; and
- include provisions dealing with:
  - the submission of future proposed revisions to the access arrangement under sections 5.29 to 5.33 of the Access Code, including specification of a revisions submission date and target revisions commencement date; and
  - trigger events under sections 5.34 to 5.36 of the Access Code that require the service provider to submit proposed amendments to the access arrangement.

82. The reasons for the Authority's Final Decision address elements of the revised proposed revisions to the access arrangement (i.e. Western Power's revised proposed access arrangement revisions) in the following order.

- The "introduction" and "definitions" sections of the access arrangement, which are additional to the elements of an access arrangement required under section 5.1 of the Access Code.
- Reference and non reference services.
- The price control and total costs and target revenue for the provision of covered services and reference services.
- Service standard benchmarks.
- Pricing methods including the actual reference tariffs determined for the first year of the access arrangement period.

- Mechanisms that affect the determination of target revenue in the next access arrangement period including efficiency and benchmarks applying to the provision of covered services.
- Trigger events.
- Standard Access Contract.
- Applications and Queuing Policy.
- Contributions Policy.
- Transfer and Relocation Policy.
- Various supplementary matters in relation to the provision of covered services that are required to be addressed in the access arrangement.

INTRODUCTION TO THE ACCESS ARRANGEMENT

Access Code Requirements

83. The introduction to the current access arrangement includes dates for revision of the access arrangement, for which specific requirements exist under the Access Code. Under sections 5.29 and 5.31 of the Access Code, an access arrangement must specify:

    - a revisions submission date that is at least six months before the target revisions commencement date; and
    - a target revisions commencement date that must be five years after the start of the access arrangement period, unless a different date is proposed by the service provider and the different date is consistent with the Code objective.

Current Access Arrangement

84. Section 1 of the current access arrangement comprises an introduction that includes the proposed purpose of the access arrangement, start date, revisions submission and commencement dates, and a list of the elements of the access arrangement. A section in this introduction describes the access arrangement's relationship to the Technical Rules and access arrangement information.

85. Section 2 of the current access arrangement relates to interpretation of certain terms used throughout the access arrangement.

86. The current access arrangement specifies a revisions submission date of 1 October 2011 and a target revisions commencement date of 1 July 2012.

Proposed Revisions

87. Proposed revisions to the introduction section of the access arrangement include:

    - a definitions and interpretations sub-section similar to Section 2 of the current access arrangement;
    - a specified date of commencement of the proposed revisions of 1 July 2012 or a later date as specified by the Authority in accordance with section 4.26 of the Access Code; and
    - a proposed revisions submission date of 1 March 2016 and a target revisions commencement date of 1 July 2017, indicating an access arrangement period of five years from 1 July 2012.

Considerations of the Authority

88. The Authority assessed the content of the introduction and definitions sections of the proposed revisions against considerations of consistency with, and ease of understanding of, the substantive elements of the current and revised access arrangements.

89. In the Draft Decision, the Authority noted that Western Power had proposed simplifying the wording of section 1.1.2. The Authority agreed the simplification of the description of the network was appropriate but considered some other parts of the existing text that Western Power proposed deleting should be retained for clarity.

90. The Authority required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 1

Section 1.1.2 of the proposed revised access arrangement must be amended to include the underlined text as follows:

"This access arrangement <u>sets out the terms and conditions under which Western Power will provide users and applicants with access</u> to the Western Power Network…"

91. In its revised proposed revisions to the access arrangement, Western Power has not accepted the required amendment and notes in the amended access arrangement information that the access arrangement is not just the terms and conditions under which Western Power will provide users and applicants with access to the Western Power Network as it deals with a variety of matters as set out in section 5.1 of the Access Code. Western Power also notes the Access Code definition of access arrangement, which states:

> "access arrangement" means an arrangement for access to a covered network that has been approved by the Authority under this Code.

92. Whilst the Authority considers the wording in the current access arrangement is clearer, it notes the points made by Western Power in its amended access arrangement information and accepts that Western Power's proposed revisions to section 1.1.2 of the Access Code are adequate.

93. Section 1.5.1 of the proposed revised access arrangement included a listing of the appendices to the access arrangement. Section 1.5.1(e) referred to Appendix C.3, the distribution low voltage connection scheme (**DLVCS**) methodology.

94. At the time of the Draft Decision the Access Code did not permit such a scheme as it fell above the threshold set for such schemes as set out in section 5.17D(b) of the Code. Consequently, the Draft Decision required the reference to Appendix C.3 to be removed and the remainder of section 1.5.1 renumbered accordingly.

Draft Decision Amendment 2

Section 1.5.1(e) of the proposed revised access arrangement must be deleted and sections 1.5.1(f) to 1.5.1(i) renumbered accordingly.

95. A Code amendment was gazetted on 17 April, which increased the threshold for such schemes from 1 per cent to 4 per cent. Following gazettal of the Code amendment, the Authority commenced the approval process for the DLVCS (which is now referred to as the distribution low voltage connection headworks scheme or **DLVCHS**) as a mid period variation to the current access arrangement. A final decision[27] was

[27] Economic Regulation Authority, Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy.

published on 3 September 2012. Consequently, Draft Decision Amendment 2 is no longer required.

96. The Authority observes that the changes proposed for section 1 of the access arrangement, other than those discussed above, are either necessary updates to reflect revisions to the access arrangement for the third access arrangement period, such as stated time periods, or are of an editorial rather than substantive nature. Accordingly, the Authority indicated in the Draft Decision that it is satisfied that the general matters addressed in the introduction and definitions of the revised proposed access arrangement are consistent with the Access Code and the Code objective.

97. The Authority assessed the proposed revisions submission date and revisions commencement date against the specific requirements of section 5.31 of the Access Code.

98. The proposed target revisions commencement date of 1 July 2017 implies an access arrangement period of five years duration from 1 July 2012. This complies with the time period specified in section 5.31(b) of the Access Code.

99. The proposed revisions submission date of 1 March 2016 is 15 months before the proposed target revisions commencement date of 1 July 2017. This complies with the time period specified in section 5.31(a) of the Access Code, which requires the revisions submission date to be at least six months before the target revisions commencement date.

REFERENCE AND NON-REFERENCE SERVICES

Access Code Requirements

100. A reference service is a service described in the access arrangement and for which a reference tariff is specified in the access arrangement. A reference service is a service that would typically be sought by a third party seeking access to the network and is in the nature of a 'benchmark service' for those seeking to negotiate access. Parties are free to negotiate any service with the service provider.

101. Section 5.1(a) of the Access Code requires that an access arrangement specify one or more reference services.

102. The requirements for reference services are set out in section 5.2 of the Access Code:

5.2 An access arrangement must:

(a) specify at least one reference service; and

(b) specify a reference service for each covered service that is likely to be sought by either or both of:

(i) a significant number of users and applicants; or

(ii) a substantial proportion of the market for services in the covered network;

and

(c) to the extent reasonably practicable, specify reference services in such a manner that a user or applicant is able to acquire by way of one or more reference services only those elements of a covered service that the user or applicant wishes to acquire; and

(d) for the covered network that is covered under section 3.1 – specify one or more reference services such that there is both:

(i) a reference service which enables a user or applicant to acquire an entry service at a connection point without a need to acquire a corresponding exit service at another connection point; and

(ii) a reference service which enables a user or applicant to acquire an exit service at a connection point without a need to acquire a corresponding entry service at another connection point.

103. The Access Code includes definitions of a number of terms that are relevant to understanding the reference services in the access arrangement.

104. "Covered service" means a service provided by means of a covered network, including:

(a) a connection service; or

(b) an entry service or exit service; or

(c) a network use of system service; or

(d) a common service; or

(e) a service ancillary to a service listed in paragraphs (a) to (d) above,

but does not include an excluded service.

"Entry service" means a covered service provided by a service provider at an entry point under which the user may transfer electricity into the network at the entry point.

"Exit service" means a covered service provided by a service provider at an exit point under which the user may transfer electricity out of the network at the exit point.

"Excluded service" means a service provided by means of a covered network, including:

(a) a connection service; or

(b) an entry service or exit service; or

(c) a network use of system service; or

(d) a common service; or

(e) a service ancillary to a service listed in paragraphs (a) to (d) above,

which meets the following criteria:

– the supply of the service is subject to effective competition, and

– the cost of the service is able to be excluded from consideration for price control purposes without departing from the Code objective.

"Reference service" means a covered service designated as a reference service in an access arrangement under section 5.1(a) for which there is a reference tariff, a standard access contract and service standard benchmarks.

"Non-reference service" means a covered service that is not a reference service.

"Reference tariff" means the tariff specified in a price list for a reference service.

105. The designation of any service as an excluded service is subject to determination by the Authority under section 6.33 of the Access Code. Other than as determined by the Authority under this section, all services provided by means of the covered network are covered services.

Current Access Arrangement

106. The current access arrangement, at sections 3.4 to 3.6A, includes the following 14 reference services:

- Anytime Energy (Residential) Exit Service, A1
- Anytime Energy (Business) Exit Service, A2
- Time of Use Energy (Small) Exit Service, A3
- Time of Use Energy (Large) Exit Service, A4
- High Voltage Metered Demand Exit Service, A5
- Low Voltage Metered Demand Exit Service, A6
- High Voltage Contract Maximum Demand Exit Service, A7
- Low Voltage Contract Maximum Demand Exit Service, A8
- Streetlighting Exit Service, A9
- Un-Metered Supplies Exit Service, A10
- Transmission Exit Service, A11
- Distribution Entry Service, B1
- Transmission Entry Service, B2
- Time of Use (Residential) – Bi-directional Service , C1

107. The current access arrangement at section 3.12 also includes a description of a range of non-reference services that are in the nature of ancillary services.

108. The current access arrangement does not specify any services as excluded services.

Proposed Revisions

109. Western Power proposed revisions to the eligibility criteria for all reference services and added three new bi-directional reference services to its list of reference services. Western Power also removed all details in relation to non-reference services from the proposed revised access arrangement.

110. Western Power advised that, as was the case for the second access arrangement period, it does not intend to provide any excluded services during the third access arrangement period.

Eligibility Criteria for Reference Services

111. Western Power noted that, from time to time, it connects large generation or load where an exemption from the Technical Rules has been agreed by the customer, or where a different service level, contract and tariff from the service standard benchmark, electricity transfer access contract and reference tariff respectively have been agreed with a customer. Western Power stated that, for ease of administration and with the customer's agreement, its practice has been to treat these different but related services as a reference service notwithstanding differences between the related service and the reference service. Western Power has proposed revising this approach for the third access arrangement period.

112. Under its proposed new approach, Western Power proposes to amend the eligibility criteria for all reference services so that consumers are not eligible for a reference service if any of the following apply:

- the consumer has been granted an exemption from the Technical Rules under section 12.34 of the Code; or
- under an agreement with Western Power:
  - the terms and conditions of the access contract under which the service will be provided are materially different to the Applicable Standard Access Contract for the service;
  - the tariff that determines the charge is different to the Applicable Reference Tariff for the service; or
  - the User is to receive delivered electricity at a service standard different to the Applicable Service Standard Benchmarks for the service.

113. Western Power stated that customers will see little practical difference and that the circumstances described are currently the subject of negotiation between the parties as if the services were non-reference services. Western Power considered the proposed revisions simply make the terminology and concepts used consistent with the requirements of the Access Code. It considered there is no change to a customer's access rights and that, if it does not provide the service sought under a reference or non-reference service, the customer has equivalent rights to seek resolution by way of arbitration. Western Power proposed that tariffs for these

services will remain in the revenue cap. This is explained further in paragraphs 196 to 197.

New Bi-directional Reference Services

114. Western Power proposes making changes to its bi-directional reference services in response to the rising demand from customers for these services, driven primarily by the increasing number of roof-top photovoltaic (**PV**) systems. Western Power noted that it undertook a review, including consultation with major stakeholders such as the Office of Energy, Synergy and other retailers. The objectives of the review were to:

- address the emerging need for a bi-directional reference service for commercial premises with on-site generation; and
- address implementation issues faced by Synergy that led to the bi-directional reference service that was introduced in the current access arrangement to cater for residential premises with small generators not being taken up.

115. In its current access arrangement Western Power has a bi-directional reference service for residential distribution network users with bi-directional energy flows due to small scale generation. This is the "Reference Service C1 - Time of Use (Residential) - Bidirectional Service". This reference service was approved by the Authority as part of Western Power's second access arrangement. However, due to concerns raised by stakeholders, the C1 reference service has not been implemented. The issues that resulted in the C1 reference service not being implemented included:

- the need to alter existing metering arrangements as the tariff was based on interval metering data for off-peak, shoulder and on-peak time periods;
- the extent of the additional implementation and transaction costs, particularly in relation to changes to the billing system and metering arrangements, and who should pay for these costs;
- the need for a bi-directional reference service for commercial customers; and
- tariff design issues.

116. The issues relating to pricing methods are discussed in paragraphs 2050 to 2060 of this Final Decision.

117. Western Power commissioned Ernst and Young to review the existing reference service and reference tariff for residential distribution users with bi-directional energy flows due to small scale generation and to define a new reference service and reference tariff for commercial distribution users with bi-directional energy flows due to small scale generation for inclusion in the third access arrangement period.

118. Based on the results of the review, Western Power proposed three new bi-directional reference services, and relabelled the existing "Time of use (residential) bi-directional service, C1", as "C3". The proposed three new bi-directional reference services are:

- Anytime energy (residential) bi-directional service, C1
- Anytime energy (business) bi-directional service, C2
- Time of use (business) bi-directional service, C4

119. The proposed time of use bi-direction services only include two time periods, on-peak and off-peak, which is consistent with the existing exit reference services (A3 and A4).

120. The proposed bi-directional reference services extend to battery storage systems and electric vehicles.

121. The proposed residential bi-directional reference services both include premises occupied by a voluntary/charitable organisation. The current C1 reference service only applies to residential premises.

122. For the proposed C1 residential anytime energy service, users are required to have an accumulation meter having capability for import and export channels. For the proposed C3 residential time of use energy reference service, users are required to have either a SmartPower meter or multiple register time of use accumulation meter having capability for import and export channels.

123. For both the proposed business bi-directional services (C2 and C4), the meter can be either an accumulation meter having capability for import and export channels or an interval meter having capability for import and export channels.

Non-reference Services

124. Western Power noted that it will continue to provide a range of non-reference services during the third access arrangement period in response to customer requirements for:

- network access services that are not reference services; and
- miscellaneous services that are ancillary to the conveyance of electricity by means of the Western Power Network (for example, the lifting of electrical wires to allow high loads to pass down highways).

125. The Authority does not currently have any evidence of significant demand for any of the existing non-reference services. However, if a significant number of users seek a particular network access service not currently offered as a reference service then, under section 5.2(b) of the Access Code, at the next access arrangement review the Authority will consider whether such services should be included as reference services.

126. The table of non-reference services provided in the current access arrangement has not been replicated in the proposed revisions to the access arrangement and all references to charges, terms and conditions for non-reference services have been deleted.

Considerations of the Authority

127. Set out below are the Authority’s considerations of the following matters relating either to proposed revisions to the access arrangement or matters raised in submissions, including:

- Changes to the eligibility criteria for all reference services.
- Additional bi-directional reference services.
- Non-reference services
- Inclusion in the access arrangement of a connection access contract as a reference service.

Eligibility Criteria for Reference Services

128. In the Draft Decision, the Authority noted that the only practical significance of Western Power's proposal to amend the eligibility criteria for reference services is that it clarifies the operation of the access disputes mechanism of Chapter 10 of the Access Code in the event that there is an access dispute over the terms or the tariff for a service. By classifying services provided with different terms, tariffs or service standards from a reference service as a non-reference service, an arbitrator would clearly not be bound to determine that the service must be provided at the reference tariff (section 10.20 of the Access Code) or provided on terms as set out in a standard access contract for a reference service (sections 10.21 and 10.22).

129. As Western Power has proposed that these non-reference services will remain subject to the revenue-cap price control, the designation of these services as a non-reference service will not alter the operation of the price control of the access arrangement.

130. The Authority considered a number of issues raised by Synergy during the first round of public consultation,[28] but did not consider they provided reason to reject Western Power's proposed approach. Each of the issues raised by Synergy is addressed below.

131. The Authority notes that the proposed amendments do not affect the ability of a user to obtain a reference service in accordance with the Technical Rules, the terms of the standard access contract and the reference tariff. This ability is ultimately enforceable by resort to arbitration on an access dispute. Accordingly, the Authority does not agree with Synergy's assertion that the proposed amendments to the eligibility criteria for all reference services has the effect of giving Western Power a discretionary ability to refuse access to reference services.

132. Synergy considered the proposed amendments to the eligibility criteria are contrary to the requirements of section 5.2(c) of the Access Code in that they prevent a user from obtaining only those elements of a covered service that the user is seeking. However, the Authority noted that section 5.2(c) of the Access Code requires that reference services be specified in such a way that a user can acquire one or more reference services to obtain only those elements of a covered service that the user wishes to acquire. This suggests that the Authority should consider whether a reference service should be divided into a number of composite services where there is evidence of significant demand for one or more components of a reference service. The Authority has no evidence of any instances where there is a significant demand for specific components of the current reference services.

133. Synergy considered the proposed eligibility criteria blurs the line between a reference service that must be provided to users and the contractual requirements for use of a service. Synergy considered a user's right to a reference service should not be conditional or linked to matters such as whether the terms of an access contract are materially different to a standard access contract or an exemption from the Technical Rules or a different service standard.

134. However, the Authority considered that a negotiated material change to the terms of a reference service (which may include a substantive departure from the technical rules

[28] Synergy, November 2011, Submission on Western Power's Proposed Revisions to the Access Arrangement.

requiring an exemption, or a different service standard) is likely to result in that service no longer being treated as the same reference service for the purposes of the Access Code. This is because the definition of a reference service in the Access Code expressly defines a reference service in section 1.3 by reference to it having "a reference tariff, a standard access contract and service standard benchmarks". The link between a reference service and its terms and conditions is also supported by section 10.21 of the Access Code, which prevents the arbitrator from determining terms for a reference service that are inconsistent with the standard access contract for the reference service.

135. Synergy considered eligibility criteria for reference services that contemplate a change to the terms of the service and cause the service to no longer be a reference service are contrary to a requirement of the Access Code that reference services should be "what the users want". The Authority rejected this argument on the basis that the issue whether users may negotiate different terms from those of a reference service is an entirely different matter from the question whether a reference service (as defined in the access arrangement and by the standard access contract) meets the requirements of section 5.2(b) of the Access Code.

136. Synergy's submission to the second round of public consultation restates its view that Western Power's amendments to the eligibility criteria are contrary to section 5.2(b) of the Access Code.

137. Section 5.2(b) of the Access Code provides that an access arrangement must specify a reference service for each covered service that is likely to be sought by either or both of:

- a significant number of users and applicants; or
- a substantial proportion of the market for services in the covered network.

138. Synergy submits that the eligibility criteria are in fact key elements of the service offered, rather than terms and conditions of the service and that the criteria needs to be taken into account in assessing whether the reference service meets the requirements of s 5.2(b) of the Access Code and is a service likely to be sought by a significant number of users or a substantial proportion of the market for services.

139. The Authority is of the view that the terms and conditions on which a reference service is to be offered are inseparable from the nature of the service. The terms and conditions determine the nature and character of the obligations undertaken by the service provider, and thereby determine the nature and character of the benefits conferred upon the user.

140. The Authority is of the view that Western Power's use of the term "eligibility criteria" may be causing some confusion for users. "Eligibility criteria" would ordinarily refer to characteristics of a user or pre-conditions to be satisfied prior to a user being "eligible" to obtain a service. However, Western Power's "eligibility criteria" do not in fact impose additional constraints or obligations on a user as a condition of obtaining a reference service. Nor do they vary the terms of a reference service. Rather, the "criteria" simply clarify and reflect the position under the Access Code that:

- a reference service is defined by reference to its reference tariff, standard access contract and service standard benchmarks; and
- material changes to any of those elements will result in provision of a different service, which a service provider is under no obligation to treat as equivalent to a reference service.

141. Western Power considers its proposed amendment of the "eligibility criteria" is necessary to clarify that it does not intend to continue its existing practice of treating "related" but different services as equivalent to the reference services. The Authority notes that, save for the exemption from Technical Rules exception, this is the position at law without the proposed new criteria in any event. The Authority does not agree that a user's exemption from the Technical Rules would necessarily result in a change to the nature or terms of a reference service as this is not one of the elements of the reference service definition. If an exemption granted did lead to a change in the nature or terms of a reference service, then this is already covered by 4) b) i) of Western Power's proposed eligibility criteria. Consequently, the Authority requires Western Power to remove criteria 4) a) from its proposed eligibility criteria.

Required Amendment 1

Western Power must remove criteria 4) a) from its proposed eligibility criteria for each reference service.

142. In the future, if the Authority is provided with evidence of significant demand for a service similar to an existing reference service but with different terms and conditions, the Authority will consider whether it is appropriate to require such a service to be specified as a reference service, in accordance with section 5.2(b) of the Access Code.

Additional Bi-directional Reference Services

143. Under clause 5.2(b)(i) of the Access Code, Western Power is required to specify a reference service for each covered service that is likely to be sought by a significant number of users and applicants.

144. The Authority considered in its Draft Decision that the number of connection points for which a business bi-directional service is required by Synergy (and potentially other users) means that the service is likely to be sought by a significant number of users. Accordingly, the Authority agreed that the proposed access arrangement revisions should make provision for a reference service for a business bi-directional connection point and that both the "anytime energy" and "time of use" reference services should apply to premises occupied by voluntary/charitable organisations as proposed by Western Power as this is consistent with existing residential reference services (A1 and A3).

145. None of the submissions received by the Authority on the Draft Decision addressed this matter and the Authority has not altered its view since the Draft Decision.

Battery and Electrical Vehicle Systems

146. Synergy identified a number of issues in relation to the provision of services to battery storage and electrical vehicle systems. In its Draft Decision, the Authority agreed that further work is needed to understand and resolve these issues. Given the issues that arose that resulted in the non-implementation of the C1 reference service during the current access arrangement period, the Authority agreed these issues should be resolved before extending the new bi-directional reference services to battery and electrical vehicle systems. The Authority noted that such services can still be provided as non-reference services.

147. The Authority required the following amendment to the proposed access arrangement revisions.

Draft Decision Amendment 3

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems unless the issues identified in paragraphs 105 to 113 above are resolved.

148. In response to the Draft Decision Amendment 3, Western Power has not accepted the required amendment because it considers it is not appropriate to discriminate against particular electrical appliances unless there is a negative safety, technical or cost impact. Western Power considers that no current safety, technical or cost issues have been identified that would give rise to the need to prohibit customers on these bi-directional services from using battery storage or electrical vehicle systems.

149. Western Power considers that many of the issues raised by Synergy are operational in nature and not matters to be resolved through the development of reference services under an access arrangement. Western Power considers there are no issues related to the network, or to the ETAC, that preclude electric vehicles or battery storage from being included in the bi-directional reference service. It also considers any issues that relate to the end-use customer's relationship with the retailer are operational, and not matters to be resolved through the development of reference services under an access arrangement.

150. Western Power's amended access arrangement information also includes the following:

- From a network perspective, a bi-directional service (like all other services) does not depend on the source of the electrical energy, whether it be a photovoltaic system, wind turbine, battery or electric vehicle. Western Power's role is to outline the standards that appliances must meet to connect to the network. It is not Western Power's role to determine the type of appliance that can or cannot be connected to the network, or to enforce the use of particular appliances on these reference services.

- Western Power acknowledges that this current assessment is based on limited experience. However, as customers increase their usage of electric vehicles and battery storage, Western Power will monitor the network impact from a technical and safety perspective. If this monitoring suggests that battery storage and electric vehicles cause a sufficiently different impact on the network compared to photo-voltaic systems, then it may be appropriate to develop a different reference service and tariff for these systems. In the absence of information supporting these impacts, these systems should not be prohibited.

151. Western Power notes Synergy's concern that inclusion of electric vehicles and battery storage in the bi-directional reference service may be contrary to government policy, and, in particular, that Synergy will require clarity from the Office of Energy on whether a customer will be entitled to a feed-in-tariff payment for electricity exported into the network, as recorded on Western Power's meter, from a battery.

152. Western Power agrees that this issue will need to be considered by the State Government as it will be possible for customers with battery storage and electric vehicle systems to receive payment for this generation under the feed-in tariff. However, it considers this is a policy issue and that it is inappropriate for Western Power to prevent this occurring through the definition of a reference service unless there is a safety, technical or cost issue.

153. Western Power notes that separate metering is not currently required by the Metering Code, the Wholesale Market Rules or the Access Code; all of which do not differentiate between generation sources. Western Power considers that if the Government does wish to distinguish generation from separate sources at a connection point, multiple metering may be required.

154. Whilst the Authority agrees that it is not Western Power's role to determine the type of appliance that can or cannot be connected to the network, other than to ensure the Technical Rules have adequate provision in relation to the standards that such appliances must meet to connect to the network, reference services must be sufficiently targeted to ensure the service provided and corresponding tariffs reflect the characteristics and costs of the service required by the customer group receiving the service.

155. The Authority considers the characteristics of network usage by electric vehicles and battery storage is likely to differ significantly from those of photovoltaic systems. Domestic photovoltaic systems clearly will only operate during daylight hours and the amount of energy exported to the network will be dependent on the energy usage profile of the relevant household and the weather conditions, whereas usage profiles for electric vehicles and battery storage are likely to be driven by quite different factors. Differences in usage profile would indicate there are also differences in network costs.

156. The Authority notes that the AEMC has undertaken a review of the energy market arrangements for electric and natural gas vehicles.[29] In its report the AEMC states:

> "… the most important choice is when EV's charge. In the worst case scenario, if EV charging is unmanaged and occurs during existing peak loads, peak load will increase. As a result distribution and transmission systems will need to be strengthened and more generation built. Conversely, if charging happens in off-peak periods, then it is not expected to increase peak load, even in high take up scenarios."

157. The AEMC's report considers the impact of home based chargers and notes:

> "… charging may require strengthening of household connections to reduce the risk of overloading. The Energy Networks Association (ENA) states in their submission that "the increase in load could cause problems for electrical systems within the household or premises where charging occurs this may also necessitate in system augmentation at the premises or site level"

158. Western Power itself made a submission to the AEMC in relation to the review in November 2011. Its submission, included the following statements:

> "The uptake of electric vehicles has a strong potential to increase peak load demand and ancillary service demands if charging is unmanaged. Peak load demand impact is shown by the following graph illustrating the last trip home with a peak in the afternoon. Coupled with the above is the assumption that people will plug in their vehicle when they arrive home. This coincides with the system peak load period and continues into the residential peak load period. The overall effect of this increased peak load will be the need to bring forward transmission and distribution asset augmentation plans in high uptake areas and result in an increase in network tariff costs to the consumer…

[29] AEMC, Market Reviews: Energy Market Arrangements for Electric and Natural Gas Vehicles , http://www.aemc.gov.au/market-reviews/open/energy-market-barriers-for-electric-and-natural-gas-vehicles.html

> However, if vehicle charging is managed through coordination of technical, regulatory and financial incentive mechanisms, to encourage off-peak charging, there is potential for significant benefits to consumers (cheaper vehicle charging costs), the network costs (increased utilisation of assets), and costs of SWIS system operation (balancing energy and ancillary service costs)."

159. Taking account of Synergy's submission and the review undertaken by the AEMC, the Authority does not agree with Western Power's assessment, in its amended access arrangement, that no current safety, technical or cost issues have been identified that would give rise to the need to prohibit customers on these bi-directional services from using battery storage or electrical vehicle systems.

160. The Authority therefore maintains the Draft Decision required amendment that the proposed revised bi-directional reference tariffs must not be extended to battery storage and electrical vehicle systems until the issues outlined above are resolved. Having now considered the matter further, the Authority also considers it is likely that reference services specifically for electrical vehicles and battery storage are likely to be required as the characteristics of such a service are quite different from those required for PV systems.

161. In the interim, as noted in the Draft Decision, services for electrical vehicles and battery storage systems can still be provided as non-reference services.

Required Amendment 2

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems.

Size of Inverter

162. In the Draft Decision, the Authority noted the threshold for inverter size for the proposed revised residential bi-directional tariffs is consistent with the current residential bi-directional tariff.

163. The Authority noted the threshold for the proposed business bi-directional tariffs of 1 MVA is consistent with the Access Code requirement for the use of average, non-locational tariffs for all connections below 1 MVA. Western Power advised that the threshold of 1 MVA will allow the reference service to cover the greater portion of the market for bi-directional services and that installations above 1 MVA would be charged on the basis of the existing entry and exit reference services for distribution customers (A8 and B1).

Metering requirements for Bi-directional Reference Services

164. In the Draft Decision, the Authority noted that the metering provisions proposed by Western Power are designed to ensure existing customers with small scale generation who have already had an upgraded two channel, five register interval meter installed at the connection point will not need their current meter arrangement altered in any way. This matter was covered by the consultation exercise carried out by Ernst and Young on behalf of Western Power, and no further comments have been made in submissions during the public consultation.

Voluntary/Charitable Organisations

165. In the Draft Decision, the Authority noted that extending the proposed revised residential bi-directional tariffs to voluntary/charitable organisations is consistent with the existing residential exit services, A1 and A3.

Non-reference Services

166. In the Draft Decision the Authority noted that Western Power's proposed revisions delete all descriptions of non-reference services from the access arrangement.

167. The Access Code does not include a requirement for an access arrangement to include a list of non-reference services. These services can be included in the access arrangement at Western Power's discretion. Regardless of whether a list of non-reference services is included or not, it does not limit the range of non-reference services that Western Power may provide, nor that a prospective user may request.

Connection Service Reference Service

168. In the Draft Decision the Authority considered a submission from Verve Energy that the access arrangement should include a connection service, preferably as a reference service or otherwise as a non-reference service on specified terms and conditions. The Authority noted in the Draft Decision that this matter had been previously considered by the Authority and its view, which has not changed, is set out below.

169. Western Power had, in its originally proposed access arrangement in 2005, specified a connection service as a non-reference service and included in the proposed access arrangement a standard access contract (the "**connection access contract**") for the connection service. The connection access contract comprised terms and conditions for a contract between Western Power and an electricity customer (who is usually the controller of a connection point). The connection access contract was intended to apply in the circumstances referred to in Verve Energy's current submission; that is, where the user of network services and the controller of the connection point are different persons. The connection access contract proposed by Western Power consisted of all the terms and conditions of the electricity transfer access contract except for those directly dealing with electricity transfer. Western Power stated the following reasons for including the connection access contract in the access arrangement as a standard access contract:

- The access contract should deal with the reference services defined in the access arrangement, being exit and entry services.
- The party receiving connection services (a non-reference service) may not be the contracted recipient of exit or entry services.
- The original contracting party to the construction of connection assets for which a contribution was required may not be a party to a contract for reference services.

170. The inclusion in the access arrangement of a connection service and an associated standard contract was addressed by the Authority in its consideration and approval of the proposed access arrangement in 2007. In its Final Decision, the Authority observed that the reference tariffs indicated in Western Power's proposed price list included charges in respect of connection assets for three reference services: the Distribution Entry Service (B1), the Transmission Entry Service (B2) and the

Transmission Exit Service (A11). The Authority concluded that the inclusion of connection charges in the reference tariffs for these services indicated that connection services are part of these reference services. The Authority further reasoned that, as it is not physically possible to utilise any of these reference services without the connection assets and services, it is appropriate for the relevant entry and exit services to be bundled with connection services in this manner. Taking these matters into account, the Authority considered that it was not necessary for connection services to be defined as separate reference services.

171. The Access Code does not require a service provider to include in an access arrangement a designation or description of non-reference services or a standard access contract for non-reference services. Under section 4.29(c), the Authority cannot require a service provider to include these matters in an access arrangement.

172. The relevant matter for the Authority to consider in response to the submission from Verve Energy is, therefore, whether the access arrangement should include a connection service as a reference service together with, necessarily, a reference tariff, a standard access contract and service standard benchmarks.

173. A connection service is defined in section 1.3 of the Access Code as "a right to connect facilities and equipment at a connection point". A note to this definition indicates that "a connection service is the right to physically connect to the network and will regulate technical compliance etc. It is not the same thing as an entry or exit service, which embody rights to transfer electricity."

174. Applying this definition, the Authority understands that the provision by Western Power of a connection service would involve executing a contract for the connection service; specifying relevant technical requirements for the connection service; provision, maintenance and operation of relevant connection assets; and monitoring of compliance with contractual and technical requirements. It is further understood that a connection service would typically be sought or provided separately from an entry or exit service for generators and for consumers of large amounts of electricity whose operations have the potential to disrupt the network. Where a price is charged for a connection service separately from a price charged for the electricity transfer service, that price would typically be specific to the party receiving the service, reflecting the cost of user-specific assets utilised for provision of the connection service.

175. Under clause 6.1(e) of the standard access contract for reference services (the "**electricity transfer access contract**" or **ETAC**) in both the current access arrangement and proposed access arrangement revisions, Western Power may require the user to procure that a controller of a connection point enter into a connection contract with Western Power in respect of a connection point. Under the definition of a connection contract in the electricity transfer access contract, the connection contract may encompass the terms of the electricity transfer access contract, other than the terms (clauses 3 to 9) that deal with the transfer of electricity, or comprise of an agreement with materially equivalent terms and conditions.

176. The Authority observes that in the National Electricity Market (**NEM**) (and under the National Electricity Rules) connection services are treated as negotiated services, meaning that the price and terms for the connection services are subject to determination by negotiation (in accordance with negotiation principles), with resolution of disputes by arbitration.

177. The Authority considers that it is not practical to include a connection service as a reference service under the access arrangement. This is because the cost of providing the connection service, and hence the relevant price for the service, would typically be specific to the party receiving the service. The only manner in which a reference tariff could be ascribed to a connection service would be to determine a separate reference tariff for each party to whom the service is provided, which would be inconsistent with the concept of a reference service as a service likely to be sought by a significant number of users or substantial proportion of the market. In the absence of a reference tariff for an individual connection service, it is not possible to include a connection service in the access arrangement as a reference service, or to require that the access arrangement include a standard access contract for a connection service.

Constrained Network Connection

178. In the Draft Decision, the Authority considered a view expressed in ERM Power's submission that charging arrangements for constrained network connections had been overlooked in Western Power's proposed revisions. The Authority noted that users are able to obtain constrained access as a non-reference service where this can be accommodated by network operating conditions. If constrained access were to be offered as a reference service, then Western Power would be required to provide the service regardless of the impact on the network. The Authority's Draft Decision also noted that consideration is being given to the merits of moving to a constrained network approach; however, this falls outside the scope of the access arrangement review process.

TOTAL REVENUE REQUIREMENT

Introduction

179. In this section of the Final Decision, the Authority addresses the determination of target revenue for the third access arrangement period and the form of the price control.

180. Western Power has determined a value of target revenue by reference to forecast costs for the third access arrangement period – the "building block" method. This is consistent with section 6.2(a) of the Access Code and with the method used to determine target revenue for the first and second access arrangement periods.

181. The Authority's assessment of Western Power's determination of target revenue is documented in the following sections of this Final Decision, addressing the following matters:

- form of price control; and
- forecast target revenue including:
  - forecasts of demand for services;
  - forecast operating expenditure;
  - amounts of actual and forecast capital expenditure and values of the regulated capital base at the commencement of the second access arrangement period and a notional regulated capital base over the term of the third access arrangement period;
  - a return on the regulated capital base;
  - treatment of capital contributions;
  - an allowance for working capital;
  - cost of taxation liabilities;
  - costs of raising additional equity;
  - adjustments to target revenue for the third access arrangement period to reflect certain cost and revenue outcomes for the second access arrangement period; and
  - an amount of tariff equalisation contributions (**TEC**).

182. In considering Western Power's proposed target revenue, the Authority has made assessments of the actual and forecast costs of Western Power over the second and third access arrangement periods, including:

- an assessment of whether the forecast operating costs for the third access arrangement period meet the requirement of section 6.40 of the Access Code of including only those costs that would be incurred by a service provider efficiently minimising costs;
- an assessment of whether capital expenditure in the second access arrangement period may be added to the capital base of the network under section 6.51A of the Access Code, including an assessment of whether, and to

what extent, the capital expenditure satisfies the new facilities investment test (**NFIT**) under section 6.52 of the Access Code; and

- an assessment of whether forecast capital expenditure for the third access arrangement period may be taken into account in determining target revenue (by notional addition to the regulated capital base), including an assessment of whether, and to what extent, the capital expenditure can reasonably be expected to –satisfy the new facilities investment test under section 6.52 of the Access Code.

183. For the purposes of the approval of proposed revisions to the access arrangement, and pursuant to sections 6.41, 6.51 and 6.51A of the Access Code, the Authority has discretion whether to recognise costs in the total costs and target revenue that underlie the price control. This includes forecast operating costs, actual capital expenditure during the second access arrangement period and forecast capital expenditure for the third access arrangement period. Before recognising these costs in total costs and target revenue, the Authority must be satisfied that the costs meet the tests of section 6.41, 6.51 and 6.51A of the Access Code. The responsibility rests with Western Power to demonstrate to the Authority that the costs satisfy these tests.

184. In making an assessment of costs, the Authority has obtained advice from Geoff Brown & Associates on a range of relevant matters including:

- a review of Western Power's forecast expenditures for the third access arrangement period;
- a review of Western Power's governance arrangements as they relate to the control of work programs and costs; and
- a review of a sample of capital projects and programs and the amounts of new facilities investment for these projects and programs claimed by Western Power to meet the new facilities investment test under section 6.52 of the Access Code.

185. In making an assessment of costs, the Authority has had regard to:

- Western Power's performance during the first and second access arrangements, in particular:
  - – significant under expenditure during the second access arrangement period compared with the forecast costs approved by the Authority in its final decision in relation to the second access arrangement period;
  - – good service standard performance during the second access arrangement period; and
  - – notwithstanding the improvements that have been made during the second access arrangement period, ongoing deficiencies in relation to Western Power's management and governance processes for undertaking operating and capital activities.
- Significant increases in Western Power's expenditure forecast for the third access arrangement period compared with actual expenditure during the second access arrangement period.
- Western Power's management of its wood poles including:
  - – an outstanding Energy Safety Order in relation to the condition of Western Power's wood poles;

  - the 2011 Asset System Review[30], which identified issues with Western Power's asset information; and
  - a recent Parliamentary inquiry into Western Power's management of wood poles, which highlighted serious weaknesses in Western Power's asset management procedures including its management of asset data.
- Efficiency of operating expenditure:
  - a comparison of Western Power's costs with other network service providers.
- Proposed methodological changes by Western Power compared with previous access arrangements that have all resulted in an increase to forecast target revenue.

186. The Authority has assessed the actual and forecast costs against the relevant requirements of the Access Code and, where it is determined that the requirements of the Access Code are not met, exercised discretion to amend the amounts of costs to be taken into account in determination of target revenue.

Form of Price Control

Access Code Requirements

187. Section 5.1(d) of the Access Code requires that an access arrangement include a price control. A "price control" is defined in the Access Code as meaning the provisions in an access arrangement under section 5.1(d) and Chapter 6 of the Access Code that determine target revenue. A note to the definition indicates that price control can consist of direct or indirect limits, and consists of a limit on the level of tariffs through the control of overall revenue. The note also distinguishes between price control and pricing methods by indicating that pricing methods in Chapter 7 deal with the structure of tariffs.

188. Sections 6.1 to 6.3 of the Access Code establish requirements for the form of the price control:

> 6.1 Subject to section 6.3, an access arrangement may contain any form of price control provided it meets the objectives set out in section 6.4 and otherwise complies with this Chapter 6.
>
> 6.2 Without limiting the forms of price control that may be adopted, price control may set target revenue:
>
> (a) by reference to the service provider's approved total costs; or
>
> (b) by setting tariffs with reference to:
>
> (i) tariffs in previous access arrangement periods; and
>
> (ii) changes to costs and productivity growth in the electricity industry;
>
> or
>
> (c) using a combination of the methods described in sections 6.2(a) and 6.2(b).

30 GHD Asset Management System Review Final Report, October 2011.

189. Section 6.3 of the Access Code constrains the choice of price control for the first access arrangement period, which is not relevant to the proposed access arrangement revisions.

190. Section 6.4(a) of the Access Code sets out objectives for the price control in relation to the setting of an amount of target revenue for the access arrangement period, which are:

> giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> (i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;
>
> plus
>
> (ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;
>
> plus
>
> (iiA) an amount (if any) determined under sections 6.5A to 6.5E[31];
>
> plus
>
> (iii) an amount (if any) determined under section 6.6;
>
> plus
>
> (iv) an amount (if any) determined under section 6.9;
>
> plus
>
> (v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);
>
> plus
>
> (vi) an amount (if any) determined under section 6.37A.

191. Sections 6.4(b) and 6.4(c) set out further objectives for the price control of:

- enabling a user to predict the likely annual changes in target revenue during the access arrangement period (section 6.4(b)); and
- avoiding price shocks (that is, sudden material tariff adjustments between succeeding years (section 6.4(c)).

Current Access Arrangement

192. The current access arrangement applies a "revenue cap" form of price control. Under this form of price control, reference tariffs are set in any year on the basis of an

[31] Sections 6.5A to 6.5E relate to the recovery of deferred revenue as set out in paragraphs 1255 to 1258.

amount of required revenue for that year, plus corrections for under-recovery or over-recovery of required revenue in prior periods. A separate revenue cap was applied to each of the transmission and distribution networks.

193. The price control also includes provisions for adjustments to revenues from one access arrangement period to the next, including provisions for adjustments for unforeseen events and technical rule changes, and adjustments under the investment adjustment mechanism and capital contributions adjustment mechanism.

194. The price control includes a separate factor for any costs incurred by the distribution system as a result of any TEC Western Power is required to pay in accordance with section 6.37A of the Code.

195. The price control under the current access arrangement is applied subject to a "side constraint" on year-to-year changes to reference tariff charges. Under the current access arrangement, the side constraint comprises a factor of +/- (CPI + 13 per cent) for the transmission network and +/- (CPI + 18 per cent) for the distribution network.[32]

Proposed Revisions

196. Western Power introduced new definitions of services in its proposed revised access arrangement for 'revenue cap services', 'non-revenue cap services' and 'bi-directional services'.

- 'revenue cap services' – means the following covered services provided by Western Power by means of the Western Power Network:
  - a) connection service;
  - b) exit service;
  - c) entry service;
  - d) bi-directional service;
  - e) the metering services provided ancillary to the services in paragraphs (a) to (d) that are defined as standard metering services in the most recent Model Service Level Agreement approved by the Authority under the *Electricity Industry Metering Code 2005*; and
  - f) streetlight maintenance.
- 'non-revenue cap services' – means non-reference services provided by Western Power by means of the Western Power Network other than non-reference services that are provided as revenue cap services.
- 'bi-directional service' – means a covered service provided by Western Power at a connection point under which the user may transfer electricity into and out of the Western Power Network at the connection point.

197. Western Power proposed that, in accordance with sections 6.1 and 6.2 (c) of the Access Code:

- a revenue cap will apply to revenue cap services that is set by reference to Western Power's approved total costs; and

[32] While expressed in this form, the side constraint is a maximum change in any tariff component by a factor of plus or minus the sum of the percentage change in the CPI and 13 percentage points for transmission tariffs and CPI and 18 percentage points for distribution tariffs.

- charges for non-revenue cap services will be:
  - negotiated in good faith;
  - consistent with the Access Code objective; and
  - reasonable.

198. Western Power proposed a new method of calculating the side-constraints for the transmission and distribution networks that will vary annually based on CPI, percentage change in revenue requirements, correction factors (including an adjustment for under and over-recovery of revenue, adjustments to revenue from the current access arrangement and the TEC) and an additional 2 per cent. The formula for calculating these side constraints is contained in Western Power's revised proposed revisions to the access arrangement.[33]

199. For the purposes of calculating the maximum target revenue each year when setting annual tariffs, Western Power proposed a number of changes:

- the published CPI data relating to the most recent December quarter compared to the December quarter in the previous year will be used rather than the March quarter, which is the requirement in the existing access arrangement;
- the formula for calculating the maximum target revenue has been amended to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year so the difference in actual revenue compared to the target revenue must be estimated and then recalculated in the subsequent financial year. In the current access arrangement period this was noted in the text of the access arrangement but not explicitly included in the formula; and
- the requirements for calculating the maximum revenue cap have been changed from "will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" to "will use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]".

Considerations of the Authority

Form of Price Control

200. Under sections 6.1 and 6.2 of the Access Code, the form of price control is a matter for determination by the service provider subject to the selected form of price control complying with the requirements of section 6.2, the objectives of section 6.4, and otherwise complying with Chapter 6. In considering a proposed form of price control for the purposes of a decision to approve or not approve the proposed access arrangement revisions, the Authority must also have regard to the Access Code objective, which requires that the price control promote the economically efficient investment in and operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.

201. A revenue cap is explicitly contemplated in the note to section 6.2(a) of the Access Code as one of several forms of price control that may be adopted.

[33] Proposed revised access arrangement, pp. 31-34.

202. A revenue cap form of price control creates an incentive for a service provider to out-perform the forecast of costs on which the price control was established, or at least to minimise any under-performance relative to that forecast. This incentive arises from the service provider bearing the risk of under-performance relative to cost forecasts, but also retaining the benefits of out-performance of forecasts.

203. A possible consequence of this is that the service provider may be incentivised to defer operating cost expenditure in order to increase out-performance. This is at least partially counteracted by the SSAM, which financially penalises the service provider for any underperformance on service standards.

204. There is also an incentive for service providers to overstate forecast operating costs in order to increase the opportunities for outperformance. The Authority needs to satisfy itself that the base operating cost expenditure used to prepare the forecasts reflects efficient expenditure and that any increases to the base costs are adequately justified by the service provider.

205. The Authority notes that a revenue cap form of price control does not provide incentives for the service provider to seek to increase demand for services and, thereby, increase revenue. The absence of such incentives under the price control could, all other things being equal, create incentives for a service provider to fail to provide timely services at new connection points. The absence of incentives under the price control is, however, countered by other mechanisms to ensure provision of services. For Western Power, these include requirements under the *Code of Conduct for the Supply of Electricity to Small Use Customers 2004*, the Customer Service Charter, and requirements of the applications and queuing policy of the access arrangement.

206. The Authority also accepts that the revenue cap form of price control could create incentives for Western Power to increase the amount of revenue that it seeks to obtain through contributions. With the treatment of contributions under the proposed access arrangement revisions, revenue obtained from contributions does not fall under the revenue cap. As such, any revenue collected by Western Power from contributions over and above forecasts is retained. However, the Authority considers that Western Power is adequately constrained in its ability to charge contributions by the contributions policy of the access arrangement, which limits the circumstances in which contributions may be charged.

207. Taking into account the matters addressed above, the Authority is satisfied that the proposed revenue cap form of price control is consistent with the requirements of the Access Code.

Revenue from Non-Reference Services

208. Under the terms of the current access arrangement, the amount of target revenue established under the price control is an amount in respect of reference services only. The derivation of target revenue involves subtracting from total costs an amount of forecast operating costs attributed to the provision of non-reference services. Under this specification of target revenue and the price control, revenue earned by Western Power from the provision of non-reference services does not fall under the revenue cap price control.

209. As set out in paragraphs 111 to 113 above, for the third access arrangement period, Western Power has proposed revisions to the eligibility criteria that may result in some network access services that are currently treated as reference services being re-

classified as non-reference services. However, Western Power has proposed that the revenue cap will apply to all network access services that Western Power provides to transmit and distribute electricity, whether they are reference or non-reference services.

210. In the Draft Decision the Authority observed that the designation as a non-reference service of a service with different terms, tariff or service standards from a reference service does not alter the operation of the price control of the access arrangement. The Authority accepted Western Power's proposal for the reason that it is consistent with the distinction between reference and non-reference services in the Access Code and that it has limited practical consequence. Therefore, the Authority accepted Western Power's proposal to include non-reference service revenue for network access services under the revenue cap.

211. The Authority noted that Western Power has proposed to treat services that are ancillary to the transmission and distribution of electricity, such as high load escorts, as falling outside of the revenue cap. This is consistent with the methodology approved by the Authority for the second access arrangement period. As this revenue falls outside the revenue cap, the forecast operating costs attributed to such services are deducted from target revenue.

Side Constraint and Calculation of Maximum Target Revenue

212. The Authority considers the operation of the side constraint and the calculation of maximum target revenue are best considered together with pricing methods, price lists and price list information. The Authority's considerations of these matters are set out in paragraphs 2033 to 2049.

Target Revenue

Access Code Requirements

213. Under section 6.2 of the Access Code, the target revenue for a price control may be set by reference to the service provider's approved total costs; or by reference to tariffs in previous access arrangement periods and changes to costs and productivity growth in the electricity industry; or using a combination of these two methods.

214. Objectives to be observed in setting the level of target revenue are set out in sections 6.4(a) and 6.5 of the Access Code.

> 6.4 The price control in an access arrangement must have the objectives of:
>
> (a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> (i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;
>
> plus:
>
> (ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and

innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;

plus:

(iii) an amount (if any) determined under section 6.6 [adjustments for unforeseen events];

plus:

(iv) an amount (if any) determined under section 6.9 [adjustments for technical rule changes];

plus:

(v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);

plus:

(vi) an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);

plus:–

(vii) an amount (if any) determined under section 6.37A [tariff equalisation contributions];

…

6.5 The amount determined in seeking to achieve the objective specified in section 6.4(a)(i) is a target, not a ceiling or a floor.

Current Access Arrangement

215. Consistent with the requirements of the Access Code, during the first two access arrangement periods, Western Power has determined a level of target revenue using a 'building-block' approach. Total revenue is comprised of:

- operating costs (non-capital costs);
- depreciation;
- return on the regulated capital base; and
- TEC[34].

216. The regulated capital base is derived as follows:

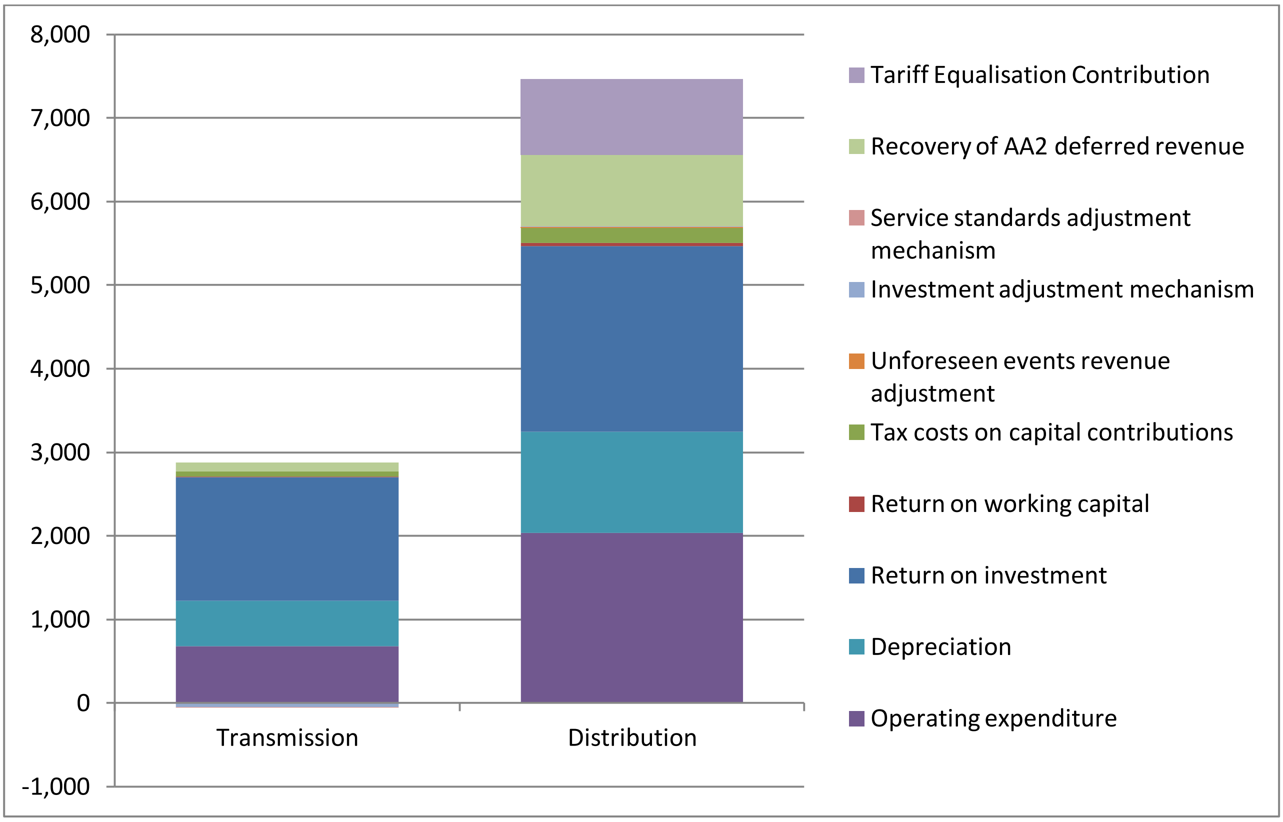
opening capital base + forecast capital expenditure – depreciation – redundant assets = closing capital base

34 The tariff equalisation contribution is an amount that Western Power is required to pay the Western Australian Government to help finance a subsidy provided to Horizon Power customers.

Proposed Target Revenue

217. Western Power initially proposed values of target revenue for the transmission and distribution networks over the third access arrangement period as indicated in Figure 1.

Figure 1 Western Power proposed transmission and distribution network target revenue (real $ million, dollar values at 30 June 2012)



218. Western Power's proposed 'building block' components of the target revenue for both the transmission and distribution network includes a number of items not included in target revenue for the second access arrangement period:

- recovery of deferred revenue from the current access arrangement;
- adding return on capital expenditure deemed to be incurred mid-year;
- provision for equity raising costs if circumstances arise; and
- recovery of tax on capital contributions.

219. A breakdown of Western Power's initial proposal for transmission and distribution network target revenue for each year of the third access arrangement period is set out in Table 2 and Table 3 below.

Table 2 Western Power initial proposed transmission network target revenue (real $ million, at 30 June 2012)[35]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Operating expenditure	125.0	122.5	132.3	142.4	156.3	678.5
Depreciation	91.2	100.9	109.2	117.8	129.6	548.7
Return on investment	250.6	273.6	289.0	311.0	346.8	1,471
Return on working capital	1.2	3.0	3.7	3.6	3.2	14.7
Tax costs on capital contributions	10.6	10.7	10.9	11.0	11.4	54.6
Forward-looking efficient costs	**478.5**	**510.7**	**545.2**	**585.9**	**647.4**	**2,767.7**
Gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0
Investment adjustment mechanism	(47.4)					(47.4)
Service standards adjustment mechanism	(0.7)					(0.7)
Recovery of current access arrangement deferred revenue	22.7	22.7	22.7	22.7	22.7	113.5
Total adjustments	**(25.5)**	**22.7**	**22.7**	**22.7**	**22.7**	**65.3**
Non-revenue cap services revenue	**(3.1)**	**(3.2)**	**(3.4)**	**(3.6)**	**(3.9)**	**(17.2)**
Maximum transmission reference service revenue unsmoothed	**449.9**	**530.3**	**564.5**	**605.1**	**666.2**	**2,816.0**
Maximum transmission reference service revenue smoothed	**486.5**	**523.7**	**559.2**	**597.3**	**638.2**	**2,804.9**

35 Revised access arrangement information, Section 13.2, Table 95.

Table 3 Western Power initial proposed distribution network target revenue (real $ million, at 30 June 2012)[36]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Operating expenditure	371.4	387.4	408.3	420.1	447.9	2,035.1
Depreciation	206.7	226.9	250.8	255.7	270.2	1,210.3
Redundant assets (accelerated depreciation)	3.4	0.5	0.0	0.0	0.0	3.9
Return on investment	375.5	407.0	444.3	480.9	514.4	2,222.1
Return on working capital	5.1	7.7	8.0	8.7	9.3	38.8
Tax costs on capital contributions	41.6	37.9	35.1	35.3	36.0	185.9
Forward-looking efficient costs	**1,003.7**	**1,067.4**	**1,146.4**	**1,200.7**	**1,277.8**	**5696.0**
Unforeseen events revenue adjustment	7.5					7.5
Investment adjustment mechanism	2.0					2.0
Service standards adjustment mechanism	3.1					3.1
Recovery of current access arrangement deferred revenue	170.7	170.7	170.7	170.7	170.7	853.5
Total adjustments	**183.3**	**170.7**	**170.7**	**170.7**	**170.7**	**866.1**
Tariff Equalisation Contribution	**181.2**	**180.7**	**180.8**	**181.7**	**182.5**	**906.9**
Non-revenue cap services revenue	**(14.9)**	**(15.3)**	**(16.0)**	**(16.8)**	**(17.9)**	**80.9**
Maximum distribution reference service revenue unsmoothed	**1,353.3**	**1,403.5**	**1,481.9**	**1,536.3**	**1,613.2**	**7,388.2**
Maximum distribution reference service revenue unsmoothed	**1,084.8**	**1,262.5**	**1,469.9**	**1,712.2**	**1,994.3**	**7,523.7**
Less TEC	(181.2)	(180.7)	(180.8)	(181.7)	(182.5)	(906.9)
Distribution revenue cap formula component	**903.7**	**1,081.7**	**1,289.1**	**1,530.5**	**1,811.8**	**6,616.8**

220. Western Power initially proposed smoothing the revenue cap based on a price path that continued the current access arrangement real increase in the average transmission tariff of 12.9 per cent from 2011/12 to 2012/13 and subsequent annual real increases in the remaining four years in third access arrangement period of 4.5 per cent (2013/14 to 2016/17). For distribution, Western Power proposed smoothing the revenue cap based on a price path that continued the current access arrangement real increase in the average distribution tariff of 16.3 per cent from 2011/12 to 2012/13 and subsequent annual real increases in the remaining four years in the third access arrangement period of approximately 11 per cent (2013/14 to 2016/17).[37]

[36] Revised access arrangement information, Section 13.2, Table 96.

[37] Revised access arrangement information, Section 13.3 Table 97.

221. Following the Draft Decision, Western Power submitted revised proposed revisions to the access arrangement which included amended forecasts of target revenue. Western Power's revised forecasts are set out in Table 4 and Table 5 below.

Table 4 Western Power revised proposed transmission network target revenue (real $ million, at 30 June 2012)[38]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Initial Proposal
Operating expenditure	125.5	124.8	129.7	140.6	153.1	673.7	678.5
Depreciation	87.3	96.3	105.9	113.1	122.6	525.2	548.7
Redundant assets (accelerated depreciation)							
Return on investment	169.0	182.8	200.2	210.3	228.1	990.4	1,471.0
Return on working capital	0.9	3.4	4.0	4.7	4.4	17.4	14.7
Tax costs on capital contributions							54.6
Plus tax payable	43.9	44.4	42.9	44.1	41.2	216.5	0.0
Less value of imputation credits	-11.0	-11.1	-10.7	-11.0	-10.3	-54.1	0.0
Forward-looking efficient costs	**415.6**	**440.7**	**472.1**	**501.8**	**539.1**	**2,369.3**	**2,767.7**
Investment adjustment mechanism	-46.4					-46.4	-47.4
Service standards adjustment mechanism	0.6					0.6	-0.7
Recovery of current access arrangement deferred revenue	12.1	12.1	12.1	12.1	12.1	60.5	113.5
Total adjustments	**-33.7**	**12.1**	**12.1**	**12.1**	**12.1**	**14.7**	**65.3**
Revenue cap correction factor							
Non-revenue cap services revenue	**3.0**	**3.1**	**3.3**	**3.5**	**3.7**	**16.6**	**17.2**
Maximum transmission reference service revenue unsmoothed	**378.9**	**449.7**	**480.9**	**510.5**	**547.6**	**2,367.6**	**2,816.0**
Maximum transmission reference service revenue smoothed-TR_t	**435.7**	**445.6**	**467.7**	**492.9**	**513.4**	**2,355.3**	**2,804.9**
% change in TR_t		**2.3%**	**5.0%**	**5.4%**	**4.1%**		

[38] Revised access arrangement information, Section 13.2, Table 95.

Table 5 Western Power revised proposed distribution network target revenue (real $ million, at 30 June 2012)[39]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Initial Proposal
Operating expenditure	386.6	401.1	409.6	415.8	433.0	2,046.1	2,035.1
Depreciation	198.2	219.9	244.2	249.6	264.8	1,176.7	1,210.3
Redundant assets (accelerated depreciation)	3.4	0.5	0.0	0.0	0.0	3.9	3.9
Return on investment	252.7	280.3	309.7	338.0	365.3	1,546.0	2,222.1
Return on working capital	3.7	8.8	9.8	10.4	10.8	43.5	38.8
Tax costs on capital contributions							185.9
Plus tax payable	86.0	109.1	143.7	196.7	259.0	793.8	0.0
Less value of imputation credits	-21.5	-27.3	-35.9	-49.2	-64.7	-198.6	0.0
Forward-looking efficient costs	**909.1**	**992.4**	**1,081.1**	**1,161.4**	**1,268.1**	**4,465.9**	**5,696.0**
Unforeseen events revenue adjustment						0.0	7.5
Investment adjustment mechanism	2.9					2.9	2.0
Service standards adjustment mechanism	9.4					9.4	3.1
Recovery of current access arrangement deferred revenue	91.2	91.2	91.2	91.2	91.2	456.0	853.5
Total adjustments	**103.5**	**91.2**	**91.2**	**91.2**	**91.2**	**468.3**	**866.1**
Tariff Equalisation Contribution	**181.2**	**180.7**	**180.8**	**181.7**	**182.5**	**906.9**	**906.9**
Revenue cap correction factor							
Non-revenue cap services revenue	**14.5**	**14.9**	**15.6**	**16.3**	**17.0**	**78.3**	**80.9**
Maximum distribution reference service revenue unsmoothed	**1,179.3**	**1,249.4**	**1,337.5**	**1,418.0**	**1,524.9**	**6,709.1**	**7,388.2**
Maximum distribution reference service revenue smoothed	**989.6**	**1,138.6**	**1,313.0**	**1,538.1**	**1,801.4**	**6,780.7**	**7,523.7**
Less TEC	(181.2)	(180.7)	(180.8)	(181.7)	(182.5)	(906.9)	(906.9)
Distribution revenue cap formula component- DR_t	**808.4**	**957.9**	**1,132.2**	**1,356.5**	**1,618.8**	**5,873.8**	**6,616.8**
% change in DR_t		**18.5%**	**18.2%**	**19.8%**	**19.3%**		

222. In its revised target revenue forecast, Western Power has also amended its method for smoothing prices. Previously Western Power has used an average tariff for smoothing. Western Power now considers this approach can be improved by incorporating the impact of customer numbers and demand as well as energy

39 Revised access arrangement information, Section 13.2, Table 95.

consumption. Western Power considers this method is better because its reference tariffs include fixed and variable components with some reference tariffs based on energy consumption and other reference tariffs based on demand (metered demand or contract maximum demand).

223. Western Power has smoothed the revenue based on applying the reference tariffs with forecast customer data for the third access arrangement period utilising existing customer data and using energy, demand and customer numbers based on the 2011 growth forecasts. Western Power forecasts that transmission tariff components will increase in real terms by 1.6 per cent per annum and distribution tariff components will increase in real terms by 13.4 per cent per annum.

Considerations of the Authority

224. As outlined above, the Authority's assessment of Western Power's determination of target revenue is documented in the following sections of this Final Decision, addressing the following matters:

- forecasts of demand for services (paragraphs 229 to 244);
- forecast operating expenditure (paragraphs 245 to 569
- amounts of actual and forecast capital expenditure and values of the regulated capital base at the commencement of the third access arrangement period and a notional regulated capital base over the term of the third access arrangement period (paragraphs 570 to 1030);
- a return on the regulated capital base (paragraphs 1031 to 1057);
- treatment of capital contributions (paragraphs 1058 to 1104);
- an allowance for working capital (paragraphs 1105 to 1143);
- cost of taxation liabilities (paragraphs 1144 to 1180);
- costs of raising additional equity (paragraphs 1181 to 1194);
- adjustments to target revenue for the third access arrangement period to reflect certain cost and revenue outcomes for the second access arrangement period (paragraphs 1196 to 1291); and
- an amount of tariff equalisation contributions (**TEC**) (paragraphs 1292 to 1297).

225. In considering Western Power's proposed target revenue, the Authority has made assessments of the actual and forecast costs of Western Power over the second and third access arrangement period.

Target Revenue

226. For the purposes of the Draft Decision, the Authority determined values of target revenue for reference services taking into account determinations and required amendments of individual elements of target revenue as set out in its Draft Decision. For the Final Decision, the Authority has updated its determined values of target revenue for reference services taking account determinations and required amendments of individual elements of target revenue as set out in its Final Decision. The values of target revenue determined by the Authority for its Final Decision are set out below in Table 6 and Table 7, together with the values determined at the Draft Decision. These tables also show the "smoothed" target revenue that becomes the revenue cap under the price control.

Table 6 Final Decision target revenue for the transmission network (real $ million at 30 June 2012)

	Final Decision						
	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Draft Decision
Operating costs	103.7	102.8	103.1	105.2	107.8	522.6	511.3
Depreciation	85.2	93.8	103.5	110.0	117.5	510.0	504.3
Accelerated depreciation (redundant assets)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred reference service revenue	10.6	10.6	10.6	10.6	10.6	53.0	54.5
Return on assets	92.1	99.7	110.2	115.1	120.6	537.6	573.6
Return on working capital	0.5	1.3	0.9	0.9	0.8	4.4	5.3
Total Gross Costs	**292.1**	**308.1**	**328.3**	**341.9**	**357.2**	**1,627.6**	**1,648.8**
Taxation	41.9	20.2	6.1	0.0	0.0	68.3	64.7
Imputation Credit	-10.5	-5.1	-1.5	0.0	0.0	-17.1	(16.1)
Investment adjustment mechanism	-47.4					-47.4	(48.2)
Service standard adjustment mechanism	6.1					6.1	(0.8)
Net costs after adjustments (unsmoothed)	**282.2**	**323.3**	**332.9**	**341.9**	**357.2**	**1,637.5**	**1,648.4**
Maximum forecast reference service revenue (smoothed)- TRt	**407.7**	**346.9**	**315.0**	**287.7**	**261.7**	**1,619.0**	**1,630.3**
% change in TR_t							

Table 7 Final Decision target revenue for the distribution network (real $ million at 30 June 2012)

	Final Decision						Draft Decision
	2012/13	2013/14	2014/15	2015/16	2016/17	Total	
Operating costs	347.8	350.9	347.0	342.6	351.6	1,739.9	1,680.4
Depreciation	194.3	214.3	237.7	242.0	255.6	1,143.9	1,139.2
Accelerated depreciation (redundant assets)	3.4	0.5	0.0	0.0	0.0	3.9	3.9
Deferred reference service revenue	79.6	79.6	79.6	79.6	79.6	398.0	408.5
Tariff Equalisation Contributions (TEC)	150.8	166.0	156.0	134.4	128.9	736.0	906.9
Return on assets	139.0	153.0	169.0	184.1	197.9	842.9	893.0
Return on working capital	2.1	2.6	2.8	3.0	3.3	13.8	13.7
Total Gross Costs	**917.0**	**966.9**	**992.1**	**985.6**	**1,017.0**	**4,878.5**	**5,045.9**
Taxation	25.2	30.7	39.9	59.6	63.4	218.7	237.4
Imputation Credit	-6.3	-7.7	-10.0	-14.9	-15.8	-54.7	59.3
Investment adjustment mechanism	1.9					1.9	1.9
Service Standard Adjustment Mechanism	24.5					24.5	2.0
Unforeseen Events Revenue Adjustment	0.0					0.0	7.2
Net costs after adjustments (unsmoothed)	**962.3**	**989.9**	**1,022.0**	**1,030.3**	**1,064.5**	**5,069.0**	**5,235.1**
Maximum forecast reference service revenue (smoothed)	**899.3**	**959.0**	**1,005.7**	**1,072.9**	**1,144.7**	**5,081.7**	**5,242.7**
Tariff Equalisation Contribution	(150.8)	(166.0)	(156.0)	(134.4)	(128.9)	(736.0)	(906.9)
Distribution reference service revenue (less TEC)-DR$_t$	**748.4**	**793.1**	**849.7**	**938.6**	**1,015.8**	**4,345.7**	**4,335.7**
% change in DR$_t$							

227. The Authority notes Western Power's view, put forward following the Draft Decision, that revenue smoothing could be improved by incorporating the impact of customer numbers and demand as well as energy consumption. The Authority considers using such a method would be highly dependent on the accuracy of these detailed forecasts and does not consider it necessary for the purposes of smoothing target revenue under a revenue cap price control. The Authority has smoothed target revenue based on total forecast energy consumption consistent with Western Power's initial proposal and previous access arrangement reviews.

Required Amendment 3

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in second last row of Table 6 and Table 7).

228. Summary comparisons of the target revenue proposed by Western Power and that determined by the Authority under this Final Decision and its previous Draft Decision are set out in Table 8 and Table 9 below.

Table 8 Transmission network target revenue comparison: Western Power proposals and Final Decision

	Western Power Initial Proposal	Draft Decision	Western Power Revised Proposal	Final Decision
Forecast revenue ($ million) (real)	$2,804.9	$1,630.2	$2,355.3	$1,619
Capital Expenditure previously disallowed as inefficient (real $ million)	$97.4	$0	$40.2	$5.1
Opening Capital Base for AA3 (real $ million)	$2,840.8	$2,593.2	$2,645.1	$2,554.7
Forecast Capital Base for AA4 (real $ million)	$4,209.8	$3,417.2	$3,924.1	$3,576.3
Capital Expenditure (real $ million)	$1,917.7	$1,328.3	$1,804.2	$1,531.6
Operating Expenditure (real $ million)	$678.6	$511.3	$673.8	$522.6
Present value of deferred revenue recovered ($ million)	$88.8	$48.6	$50.6	$47.7
Forecast average tariff increase 1 July 2012[40]	CPI + 12.9%	CPI - 10.6%	CPI + 0.2%	CPI – 11.3%
Forecast average tariff increase 1 July 2013	CPI + 4.5%	CPI - 10.6%	CPI + 0.2%	CPI – 11.3%
Forecast average tariff increase 1 July 2014	CPI + 4.5%	CPI - 10.6%	CPI +2.5%	CPI – 11.3%
Forecast average tariff increase 1 July 2015	CPI + 4.5%	CPI - 10.6%	CPI + 2.3%	CPI – 11.3%
Forecast average tariff increase 1 July 2016	CPI + 4.5%	CPI - 10.6%	CPI + 1.6%	CPI – 11.3%

40 Final Decision assumes revised tariffs come into effect on 1 January 2013.

Table 9 Distribution network target revenue comparison: Western Power proposal and Final Decision

	Western Power Initial Proposal	Draft Decision	Western Power Revised Proposal	Final Decision
Forecast revenue ($ million) (real)	$7,523.7	$5,242.6	$6,780.7	$5,081.7
Capital Expenditure previously disallowed as inefficient (real $ million)	$147.1	$0	$71.4	$0
Opening Capital Base for AA3 (real $ million)	$4,257.2	$3,932.0	$3,954.2	$3,855.6
Forecast Capital Base for AA4 (real $ million)	$6,205.0	$5,599.1	$6,129.6	$5,862.9
Capital Expenditure (real $ million)	$3,162.1	$2,810.3	$3,355.9	$3,155.1
Operating Expenditure (real $ million)	$2,035.0	$1,680.5	$2,046.1	$1,739.9
Present value of deferred revenue recovered ($ million)	$667.2	$365.2	$380.1	$358.3
Forecast average tariff increase 1 July 2012[41]	CPI + 17.6%	CPI + 2.5%	CPI + 11.2%	CPI + 3.3%
Forecast average tariff increase 1 July 2013	CPI + 13.4%	CPI + 2.5%	CPI + 13.3%	CPI + 3.3%
Forecast average tariff increase 1 July 2014	CPI + 13.4%	CPI + 2.5%	CPI + 13.6%	CPI + 3.3%
Forecast average tariff increase 1 July 2015	CPI + 13.4%	CPI + 2.5%	CPI + 13.4%	CPI + 3.3%
Forecast average tariff increase 1 July 2016	CPI + 13.4%	CPI + 2.5%	CPI + 13.4%	CPI + 3.3%

[41] Final Decision assumes revised tariffs come into effect on 1 January 2013.

Forecast Demand for Services

Western Power's Forecast Demand

229. In its proposed access arrangement revisions submitted on 30 September 2011, Western Power forecast that over the third access arrangement period the average annual growth will be:

- 146 MW per year (3.2 per cent) increase in peak demand compared with the average annual increase from 1998/99 to 2009/10 of approximately 147 MW;
- 2.4 per cent annual increase in the number of customers similar to the increase in the 2005/06 to 2010/11 period of 2.5 per cent per year; and
- 2.8 per cent average annual increase in energy consumed by distribution-connected customers.

230. Western Power based its proposal on the November 2010 demand forecast, as set out in its 2010 Annual Planning Report. Western Power updates its demand forecasts annually. Western Power noted in its Access Arrangement Information that it did not anticipate that the 2011 Annual Planning Report forecast would result in a material impact on its demand forecast.

231. In its revised proposed access arrangement revisions submitted on 29 May 2012, Western Power has taken into consideration the 2011 Annual Planning Report demand forecasts that were not available at the time of the initial submission on 30 September 2011.

232. Western Power's revised calculations for the average annual growth are:[42]

- Peak demand forecast has been revised downwards from an average annual increase of 3.2 per cent to a 2.9 per cent increase;
- Number of customers forecast has been revised upwards from an average annual increase of 2.4 per cent to a 2.7 per cent increase; and
- Energy consumed by distribution-connected customers forecast has been revised downwards from an average annual increase of 2.8 per cent to a 2.2 per cent increase.

Considerations of the Authority

233. A submission from the West Australian Major Energy Users (**WAMEU**) on Western Power's proposed access arrangement revisions acknowledged that, while it did not have better data than Western Power in forecasting demand, it has observed 'that over time the error in the forecast of demand tends mainly to reflect a deferment of projects rather than projects being brought forward' and that the economic growth of the North West of Western Australia is likely to have disproportionately affected the average State Gross State Product compared to what is likely to occur in the South West. The WAMEU also considered that there is a strong incentive for demand side responsiveness to limit the growth in demand and that there needs to be careful

[42] May 2012, Western Power, *Revised Access Information - Appendices, Appendix H – Revised 2011 Growth Forecasts*.

assessment of forecast increases in demand.[43] Under a revenue cap form of regulation, there is an incentive for the regulated business to over-forecast demand to ensure higher approved expenditure amounts to meet that demand. WAMEU notes that Western Power's forecast consumption is below the levels implied by the Independent Market Operator (**IMO**) 2011 Statement of Opportunities, resulting in higher forecast tariffs per GWh.

234. In its Draft Decision, the Authority noted that the risk of over-forecasting demand observed by WAMEU is partly addressed through the Investment Adjustment Mechanism which adjusts Western Power's target revenue at the next access arrangement review to take account of differences between actual and forecast expenditure in demand-related capital expenditure. However, the Authority noted that it is important to ensure the robustness of the demand forecasts. To this end, the Authority's technical adviser, Geoff Brown & Associates (**GBA),** was requested to assess a representative sample of individual capital expenditure projects and programs to assess their certainty and reliability and also whether alternative non-network solutions exist.

235. Subsequent to Western Power's proposal for the third access arrangement period being submitted to the Authority, Western Power's 2011 Annual Planning Report was released which indicated that peak demand will not increase as quickly as expected in the 2010 report.[44] The reduction in peak demand is a material change from forecasts in 2010 and GBA noted that up to 40 per cent of Western Power's growth-driven forecast transmission capital expenditure could be deferred to the fourth access arrangement based on these new forecasts.[45]

236. Load forecasting entails a level of uncertainty which is likely to be greater at a sub-regional level. As the requirements for distribution capacity expansion capital expenditure, unlike transmission capital expenditure, are more related to sub-regional forecasts, GBA proposed that minor distribution capacity expansion should be reduced by 20 per cent rather than the 40 per cent adopted for transmission expenditure.[46]

237. After assessing all available information, the Authority formed the view in its Draft Decision that the most recent data available, being the 2011 Annual Planning Report, should be used for determining expenditure parameters.

238. Accordingly, all capital expenditure that is affected by the revised forecast peak demand calculations was amended.

239. In its submission on the Draft Decision, the WAMEU concurs with the Authority that it is appropriate to set the forecast increase in demand on the basis of the latest information available.

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43 November 2011, Western Australian Major Energy Users. Electricity Distribution and Transmission Services in the Western Power South Western Interconnected System: Response to the Application, p. 18.

44 Western Power, 2011 Annual Planning Report, http://www.westernpower.com.au/aboutus/publications/2011apr/index.html

45 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 7.2.6, p. 80.

46 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.3.5, p. 97.

240. The WAMEU also reiterates its concern that there is an incentive for Western Power to overstate its expected growth in demand, although it acknowledges that the Incentive Adjustment Mechanism does reduce this incentive slightly.[47]

241. Western Power has noted that a number of factors have contributed to the lower 2011 peak demand forecasts including the reduction in peak demand growth predominantly due to the impact of PVs (photovoltaics).[48] The impact of PVs also affects the energy consumption forecasts.

242. Western Power has stated that its forecast increase in the annual average customer numbers is due to a combination of a change in using more recent data, input assumptions and a revised modelling approach.

243. Western Power's 2011 energy consumption forecast is lower than previous forecasts due to the inclusion of new inputs and data that was not included in the proposed access arrangement submission in September 2011, such as the impact of PVs, weather variation and increasing retail electricity prices.

244. As discussed previously, Western Power has now used the 2011 demand forecasts to amend its associated forecasts for operating and capital expenditure. This was a requirement by the Authority in its Draft Decision, as noted in paragraph 237. As a result, the Authority accepts Western Power's demand forecasts. However, Western Power considers the effect of using the 2011 Annual Planning Report demand forecasts is in a more modest reduction to its forecast expenditure than the Authority determined in the Draft Decision. The Authority's assessment of Western Power's revised proposed operating and capital expenditure forecasts are discussed in more detail below.

Forecast Operating Expenditure

Access Code Requirements

245. Section 6.40 of the Access Code provides for the approved total costs and target revenue to include an amount in respect of forecast non-capital costs (operating costs) for the access arrangement period.

> 6.40 Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

246. Sections 6.41 and 6.42 of the Access Code provide for the non-capital costs component of approved total costs to include non-capital costs incurred in relation to an "alternative option" for providing covered services, subject to certain conditions being met. An alternative option refers to an activity undertaken by Western Power for the purposes of providing a covered service as an alternative to investing in a major augmentation of the network, and may include such activities as demand-side management or generation either instead of, or in addition to, network augmentation.

47 June 2012, WAMEU, Submission on the Authority's Draft Decision, p. 16.

48 The number of photovoltaic systems has increased significantly over the last few years due to various government incentives.

6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:

(a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising costs; and

(b) at least one of the following conditions is satisfied:

(i) the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or

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

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

6.42 For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:

(a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income 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 alternative option not been undertaken); 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 (other than alternative option 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 section 6.42(a)),

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 this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.

Western Power's Proposal

247. In the proposed revisions to the access arrangement submitted on 30 September 2011, Western Power forecast total operating expenditure (non-capital costs) of $2,713.6 million (real dollars at 30 June 2012) over the five year third access arrangement period, with $678.6 million required for the transmission network and $2,035.0 million for the distribution network. A breakdown of these amounts, together with the forecasts and estimated actual costs for the current access arrangement period, are shown in Figure 2 and Figure 3.

Figure 2 **Transmission network operating expenditure (real $ million at 30 June 2012)**[49]

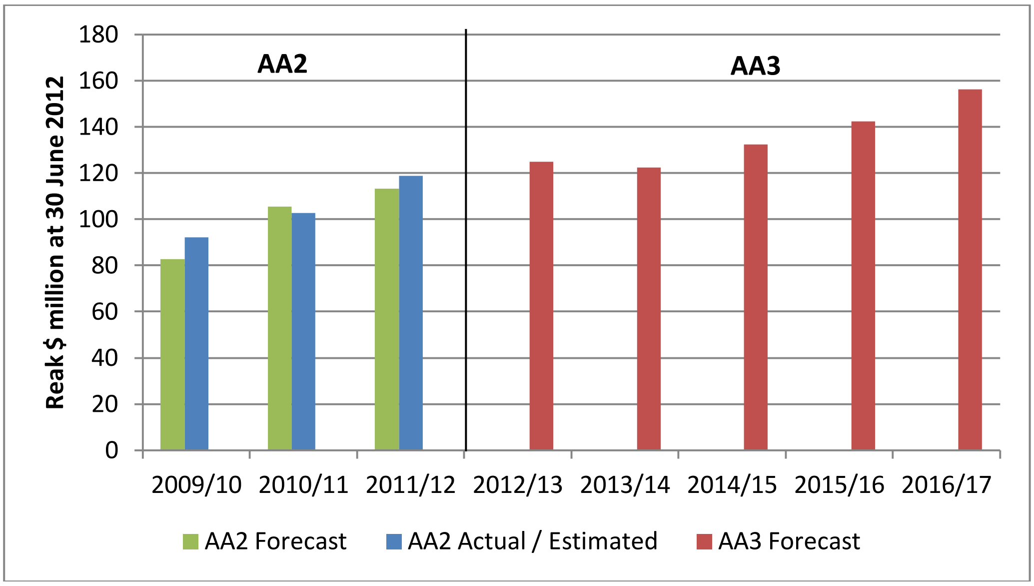
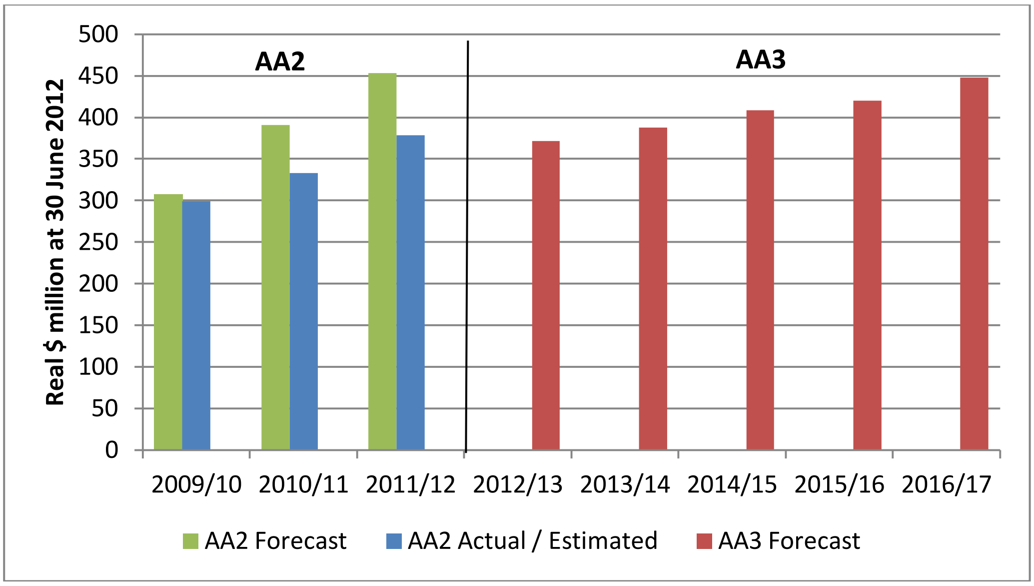


Figure 3 **Distribution network operating expenditure (real $ million at 30 June 2012)**[50]



248. Western Power has provided supporting information for its forecasts in section 7 and Appendix A of the revised access arrangement information.

249. Western Power's actual operating expenditure for the current access arrangement period (in real dollar terms) was around 4 per cent in excess of the forecast (in real

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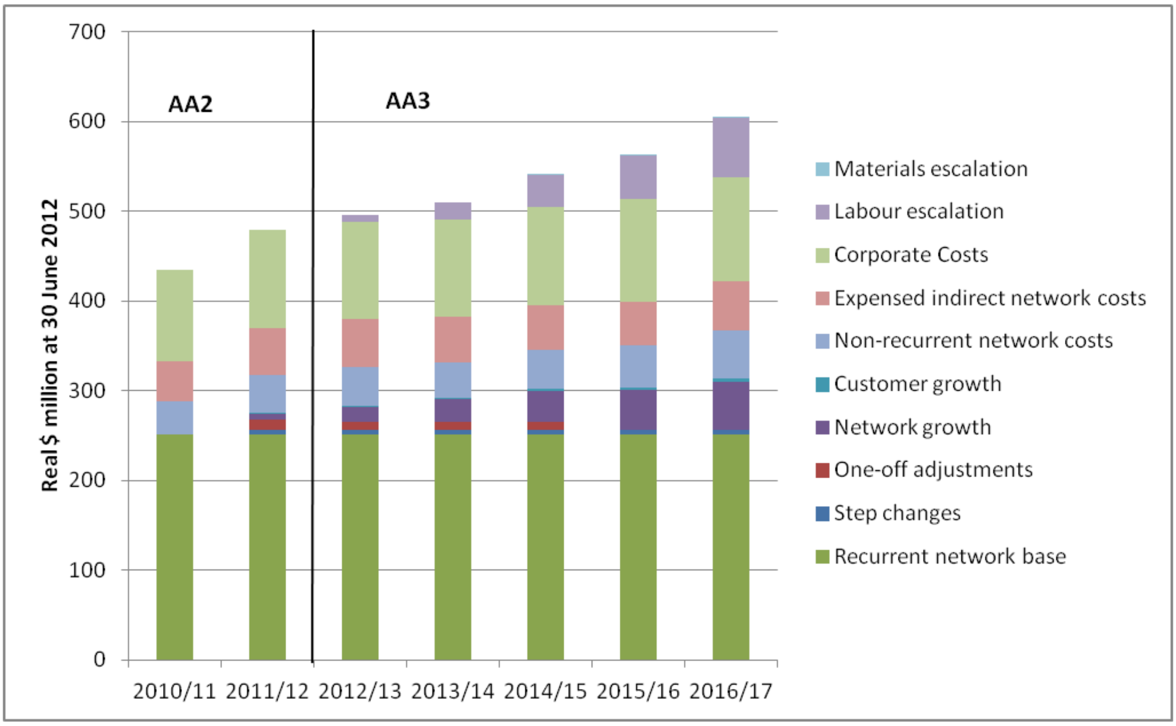
49 4 December 2009, Economic Regulation Authority, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network; Revenue Model; and Revised access arrangement information for AA3.

50 4 December 2009, Economic Regulation Authority, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network; Revenue Model; and Revised access arrangement information for AA3.

dollar terms) for the transmission network, but 12 per cent below the forecast for the distribution network.

250. Western Power forecast its recurrent operating expenditure assuming that 2010/11 was an efficient base year and maintained that cost in real terms across the forecast period. As shown in Figure 4 below, Western Power then added to recurrent expenditure by including costs for step changes, one-off adjustments, network growth and customer growth. With the exception of $0.3 million per annum, relating to savings gained by combining certain projects, Western Power did not assume any future efficiencies in its forecasts.

Figure 4 Components of total operating expenditure for transmission and distribution network (real $ million at 30 June 2012)[51]



251. Western Power forecast substantial real increases in operating expenditure over the actual costs incurred in the current access arrangement period, with the forecast level of operating expenditure in 2016/17 around 33 per cent higher than the actual level in 2010/11. The most significant increases in forecast operating expenditure related to:[52]

- growth in the size of the network and customer numbers;
- forecast movements in real labour costs; and
- non-recurring costs for network control services, the introduction of new technologies, the field survey data capture project and removal of transmission lines that are no longer in service.

252. In the revised proposed access arrangement revisions submitted on 29 May 2012, Western Power has amended its forecast operating expenditure. These amendments are considered below under "Considerations of the Authority".

51 Revised access arrangement information, Section 7.2, Table 27.

52 Revised access arrangement information, Section 7.1, p. 129.

Considerations of the Authority

253. Under section 6.40 of the Access Code, the Authority must be satisfied that the forecast operating costs for the third access arrangement period include only those costs that would be incurred by a service provider efficiently minimising costs.

254. Western Power proposed forecasts of operating expenditure which embodied significant real increases over actual costs in the current access arrangement period in almost all categories of expenditure. Table 10 below sets out Western Power's initial proposed operating expenditure.

Table 10 Western Power's Initial Proposed Operating Expenditure (real $ million at 30 June 2012)

Expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base	251.8	251.8	251.8	251.8	251.8	251.8	251.8	1,259.1
Step changes		4.0	5.0	5.0	5.0	5.0	5.0	25.0
One-off adjustments		11.5	8.7	8.7	8.7			26.1
Network growth		7.3	16.4	25.2	34.3	43.6	53.0	172.5
Customer growth		0.6	1.3	1.9	2.6	3.3	4.0	13.1
Total recurrent network costs	**251.8**	**275.2**	**283.2**	**292.6**	**302.4**	**303.7**	**313.9**	**1,495.8**
Non-recurrent network costs	**36.0**	**42.3**	**42.9**	**38.6**	**42.9**	**47.0**	**52.9**	**224.4**
Expensed indirect network costs	44.9	52.2	54.3	51.3	50.2	48.3	54.9	259.1
Corporate costs	**102.5**	**109.3**	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**	**555.9**
Input cost escalation			8.1	19.7	35.2	49.1	66.3	178.4
Total AA3 operating expenditure[53]	**435.3**	**479.0**	**496.4**	**509.9**	**540.6**	**562.5**	**604.2**	**2,713.6**

Source: Western Power's Access Arrangement Information, Table 27.

255. The Authority has approached the forecast of operating expenditure by first considering the levels of expenditure during the second access arrangement period. The focus of the Authority's consideration of forecasts of operating expenditure was, firstly, to consider whether the most recent recorded actual operating expenditure for the second access arrangement period (i.e. the year 2010/11) is consistent with the costs that would be incurred by a service provider efficiently minimising costs and, secondly, whether Western Power has adequately substantiated and justified

53 Western Power has included expenses for non-revenue cap services of $98.1 million in non-recurrent network costs and this is also included in total operating expenditure for the third access arrangement period. Western Power then deducts this non-revenue cap expenditure from target revenue.

differences in forecast operating expenditure from the actual operating expenditure incurred in that year.

256. The process adopted by the Authority in considering the forecasts of operating expenditure has therefore been to:

- verify records of actual operating expenditure for the first two years of the second access arrangement period for which actual cost data are available (2009/10 and 2010/11);
- assess the extent to which the actual operating expenditure for the current access arrangement period would be incurred by a service provider efficiently minimising costs, consistent with the requirements of section 6.40 of the Access Code, in order to establish an efficient level of base operating expenditure; and
- assess whether Western Power has provided adequate justification for forecast trends and step changes in levels of operating expenditure over the term of the third access arrangement period.

257. During the second round of consultation, the Energy Networks Association (**ENA**) submitted that the Authority's approach to determining forecast operating expenditure combines a range of approaches without any clear articulation of their relationship to each other, and risks failing to meet the criteria in section 6.4 of the Access Code.[54] The ENA notes that the Authority had applied a line item level reduction to forecasts based on expert engineering advice, revised labour and material input cost escalation, and used high level 'top down' partial factor benchmarking approaches to apply scope and scale efficiency factors.[55]

258. The ENA considers that:

> "the reduction of forecasts based on adjustments to reveal base year expenditure, which is assumed to be a reflection of the operation of existing incentives, when combined with outcomes justified by high level top down benchmarks which fail to take into account relevant network characteristics, and a broad undocumented assumption about likely potential efficiency gains, risks delivering a forecast that has no transparent or rational basis".[56]

259. The Authority notes it has assessed the overall operating expenditure forecasts having regard to the price control objectives section 6.4 of the Access Code. The Authority has used the same assessment techniques it used in the Draft Decision (which are discussed in further detail below). This approach involves adopting Western Power used a scale escalation model approach and the Authority has adopted a similar approach. The Authority consider that its approach is appropriate as it ensures an efficient base year and appropriate factors to use for escalation (both in size and for real labour and material input cost escalation) and makes an efficiency assessment of non-recurrent expenditure, while at the same time acknowledging that Western Power will achieve new cost efficiencies during the third access arrangement period. The Authority considers that this approach is consistent with the price control objectives in section 6.4 of the Access Code.

Verification of Operating Costs in the Second Access Arrangement Period

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54 May 2012, Energy Networks Association, Submission on the Authority's Draft Decision, p. 2.

55 May 2012, Energy Networks Association, Submission on the Authority's Draft Decision, p. 2.

56 May 2012, Energy Networks Association, Submission on the Authority's Draft Decision, p. 2.

260. In accordance with the Authority's *Guidelines for Access Arrangement Information*[57], Western Power provided regulatory accounts that reconcile costs of regulated activities with a set of base accounts for the business.[58] These regulatory accounts provide the following reconciliation of claimed operating costs with recorded operating costs.

Table 11 Reconciliation of claimed operating expenditure for 2009/10 and 2010/11 with recorded operating expenditure for the Western Power business (real $ million at 30 June 2012)

Network and Year	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs	Access Arrangement Forecast
Transmission 2009/10	86.0	6.2	92.2	92.2	82.6
Transmission 2010/11	113.4	-10.8	102.6	102.6	105.4
Distribution 2009/10	289.2	9.8	299.0	299.0	307.3
Distribution 2010/11	327.5	5.9	333.3	333.3	390.8

261. The adjustments included:

- In 2009/10 the reclassification of the cost of unregulated fleet and regulated information technology depreciation as regulated operating expenditure costs (via the approved works program) and not depreciation and amortisation.
- In 2010/11 the reclassification of depreciation as operating expenditure to offset the credit (from business unit charge recovery) in Corporate operating expenditure costs and to reverse the 2010/11 statutory write down for cancelled/deferred capital projects.

262. The Authority observed that the regulatory accounts presented by Western Power were audited for Western Power by the Office of the Auditor General. As set out in the Draft Decision, the Authority had the regulatory accounts independently reviewed[59] and is satisfied that the regulatory accounts provide a true and correct record of operating costs in 2009/10 and 2010/11.

263. However, the Authority notes the comments in BDO's report which indicates Western Power and System Management are yet to finalise the Ring Fencing Guidelines for System Management.[60]

Operating Costs in the Second Access Arrangement Period

264. The Authority has considered whether the actual operating costs for the current access arrangement period are consistent with a service provider efficiently minimising costs and therefore constitute a relevant cost base against which forecasts of non-capital costs for the third access arrangement period can be assessed.

57 6 December 2010, Economic Regulation Authority, *Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information (Version 2)*.

58 30 September 2011, Western Power, *Proposed Revisions to Access Arrangement – Access Arrangement Information Appendix G & Appendix H*.

59 March 2012, BDO, *Agreed Upon Procedures Engagement – Western Power's Access Arrangement for the South West Interconnected Network*.

60 March 2012, BDO, *Agreed Upon Procedures Engagement – Western Power's Access Arrangement for the South West Interconnected Network*, Section 2.6, p. 36.

265. Submissions from a number of interested parties, during the first round of public consultation, were concerned with Western Power's choice of base year and to what extent it had been reviewed and adjusted to ensure only efficient costs were included.[61] Submissions also commented on the underspend during the second access arrangement period in relation to the forecasts included in target revenue during the second access arrangement review.

266. Based on its own benchmarking of Western Power against other Australian electricity networks, the WAMEU suggested that Western Power is generally more expensive than its comparators, as in most cases its current performance is above the line of average performance. WAMEU noted that most similar businesses are lower cost performers than Western Power. WAMEU considers that the data provided by Western Power shows that the performance for the third access arrangement period will be more expensive than the current performance, reinforcing the view that the claimed operating expenditure is considerably higher than it needs to be.

267. In reviewing the forecast operating expenditure for the third access arrangement period, the Authority sought advice from GBA.[62] GBA assessed the efficiency of Western Power's base year (2010/11) operating expenditure by:[63]

- reviewing the incentives for Western Power to minimise its operating expenditure;
- benchmarking the base year operating expenditure against operating expenditure reported by other network service providers in Australia; and
- reviewing individual base year operating expenditure line items (at a high level) for reasonableness.

268. Western Power suggested in its Amended Access Arrangement Information that the Authority accepted that the 2010/11 actual costs are the appropriate base year to use to project operating expenditure for the third access arrangement period. However, as discussed below, the Authority in its Draft Decision did not accept the 2010/11 actual costs and made a number of adjustments to these costs. The Authority accepted an adjusted 2010/11 operating cost amount to project operating expenditure in the Draft Decision. The Authority was also concerned about the strength of the incentives for Western Power to minimise operating expenditure and its performance compared to its peers.

269. Western Power has not accepted all of the base year (2010/11) adjustments in its Amended Access Arrangement Information and has criticised GBA's benchmarking analysis. GBA has provided advice to the Authority, in response to Western Power's concerns, which are noted in the sections below.

Incentives to Minimise Operating Expenditure

270. In its review prior to the Draft Decision, GBA considered that there was an incentive for Western Power to minimise its base year operating expenditure (since it can retain any underspend for a given year as profit) but that this incentive was not as strong as

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61 WALGA, Alinta, WAMEU.

62 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*.

63 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3, p. 114.

intended due to the requirements of the gain sharing mechanism not being met during that year.[64] The approved gain sharing mechanism allowed Western Power to retain operating expenditure efficiency for a five year period (see section on Adjustments to Target Revenue in the Next Access Arrangement Period paragraphs 2088 to 2281).[65] The gain sharing mechanism does not apply if service standard benchmarks are not met in a given year. Western Power did not meet a small number of service standard benchmarks in both 2009/10 and 2010/11, and was not expected to meet a few benchmarks in 2011/12. As a result, Western Power will not receive any reward from the Gain Sharing Mechanism even though Western Power has significantly underspent the approved current access arrangement period operating expenditure levels.

271. GBA noted that, in using Western Power's proposed scale escalation model to forecast operating expenditure, a higher base year operating expenditure assessment will result in larger cost increases in each year of the access arrangement.[66] This is because escalators are applied to a higher starting amount and this is compounded over the period, which is why it is very important to ensure the base year operating expenditure is appropriate. GBA also noted that the asymmetrical gain sharing mechanism (there is no carry-forward penalty if there is an overspend), may create a perverse incentive for a service provider to increase operating expenditure to inefficient levels, particularly at the end of the regulatory period in the hope that this will lead to an increase in the regulatory operating expenditure provision in the next access arrangement period.[67]

272. In its Draft Decision, the Authority considered that there is some merit in adopting a symmetrical gain sharing mechanism. However, if costs were higher than the approved amount for valid reasons, such a mechanism may lead to the service provider being penalised unfairly. As a result, the Authority did not consider there is a need at this stage to make the mechanism symmetrical.

273. The Authority considered that Western Power had some incentives to efficiently minimise operating expenditure by virtue of the incentive properties of the revenue cap price control applying under the current access arrangement. That is, Western Power would have had an incentive to seek efficiencies in operating costs due to an ability to retain the benefits of cost savings, relative to the forecasts on which the price control was set, and also due to Western Power being exposed to the risk of cost overruns relative to the forecasts. However, the Authority agreed with GBA's view that the incentive properties inherent in the revenue cap price control under the current access arrangement could have been stronger.

274. Following the Draft Decision, Western Power has provided its actual 2011/12 performance to the Authority which indicates that it did not meet a few of the service standard benchmarks in 2011/12. As discussed above, the gain sharing mechanism will not apply to Western Power.

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64 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

65 Also, Western Power's current access arrangement requires all service standard benchmarks to be met in a given year in order for the gain sharing mechanism to apply.

66 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

67 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

275. During the second round of consultation, the WAMEU reviewed the benchmarking undertaken by GBA[68] and submitted that the incentive scheme during the current access arrangement must have been "underpowered" because Western Power's operating expenditure during this period 'is demonstrably less efficient than operating expenditure in the NEM regions'.

276. The Authority remains of the view that the incentive properties inherent in the revenue cap price control under the current access arrangement could have been stronger.

Benchmarking Analysis

277. In its review prior to the Draft Decision, GBA undertook a benchmarking exercise for Western Power's base operating expenditure (2010/11) against the latest available operating expenditure levels recorded in other States. Due to differences in the manner in which Western Power classifies transmission and distribution assets compared with counterpart businesses in the rest of Australia, the benchmarking was carried out by combining the services.

278. Since the size of the networks differs in the different States, there was a need to normalise the performance for comparative purposes. The AER publishes an annual Electricity Performance Report for transmission service providers in which it uses line length and capital base value as normalisers. Both of these normalisers are also used for distribution networks along with a common distribution normaliser of customer numbers. GBA decided to use three normalisers – operating expenditure per km of line length, operating expenditure per customer and operating expenditure as a percentage of the regulated asset base – for comparative purposes. While GBA cautioned that its analysis did not use a fully consistent data set, it was 'confident that the benchmarking is sufficiently accurate to be indicative of the relative efficiency of the electricity network operation in all the States considered.'[69]

279. The Authority noted that the three chosen normalisers differ slightly from the ones used by Western Power in its access arrangement information in which it chose peak demand, line length and customer numbers. Peak demand was not considered by GBA as network companies are essentially asset managers and a high proportion of their operating expenditure is maintenance related. The Authority agreed with this assessment and considers that the three normalisers chosen by GBA are more appropriate for operating expenditure benchmarking for Western Power.

280. The Authority also considered that GBA's benchmarking analysis is superior to Western Power's benchmarking due to the definitional issues with respect to categorising transmission and distribution expenditure. While Western Power has noted that it has tried to allocate costs between transmission and distribution to replicate its peers' definitions of transmission and distribution, GBA's benchmarking does not rely on aligning the definitions and avoids any errors as a result of realignment. Also, GBA's benchmarking analysis has been based on the most recent available data, whereas Western Power's analysis uses a three year average to 2008/09 for transmission and the point estimate of 2009/10 for distribution.

281. The result of GBA's benchmarking analysis is shown in Table 12 below.

68 June 2012, WAMEU, Submission on the Authority's Draft Decision, p. 42.

69 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 115.

Table 12 Geoff Brown & Associates Operating Expenditure Benchmarking Results (real $ million at 30 June 2012)

Network	Opex/km line	Opex/Customer	Opex/RAB (%)
Western Power	4,507	433	7.2%
Queensland	4,053	436	4.2%
New South Wales	4,814	409	6.0%
Victoria	3,900	248	6.1%
South Australia	2,724	309	5.7%
Tasmania	3,965	407	5.0%

Source: Geoff Brown & Associates 2012*. Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* www.erawa.com.au, p. 115.

282. GBA advised that Western Power does not perform well on any of the benchmarks in comparison with other States and that the results indicate that efficiency gains are available.[70]

283. GBA considered that capturing any efficiency gains that may be available to Western Power could take time and, therefore, it is more reasonable to capture these efficiency gains by incorporating an efficiency factor into the forecast operating expenditure for the third access arrangement period rather than to apply an immediate adjustment to the base year expenditure.[71]

284. As noted in paragraph 266 above, a submission from the WAMEU to the first round of public consultation included benchmarking that it had undertaken. Based on this work, the WAMEU considered that Western Power is generally more expensive than its comparators, as in most cases its current performance is above the line of average performance.

285. In its Draft Decision, the Authority noted the benchmarking analysis undertaken by GBA and the submission from the WAMEU and was concerned with the performance of Western Power in light of the comparators. The Authority agreed with GBA that there should be efficiency gains available to Western Power and that an efficiency factor should be incorporated into the forecasts of operating expenditure. While it may be argued that a global adjustment to the base year operating expenditure could be applied because Western Power did not perform well in comparison with other States, the Authority considered that, in this case, it is best to incentivise Western Power to meet more efficient operating expenditure levels through an adjustment to forecast operating expenditure during the third access arrangement period. This will be discussed further in paragraphs 535 to 561.

286. While not directly related to the consideration of base year operating expenditure for the third access arrangement period, the Authority noted in its Draft Decision that it was concerned about the relative difficulty in undertaking benchmarking analyses between Western Power and its peers in Australia. While the usefulness of benchmarking has been a perennial issue in regulation of natural monopolies in

70 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.2, p. 115.

71 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.2, pp. 115-116.

Australia before and since the inception of incentive-based regulation in Australia, the issue seems to have received more focus in recent times.

287. The Productivity Commission released an issues paper in February 2012, on its review of the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure in the NEM.[72] If there is a subsequent requirement for network service providers in the NEM to provide a set of consistent data to enable benchmarking, the Authority will make an assessment as to its applicability in Western Australia. In any case, the Authority is considering improvements in benchmarking analysis to be undertaken in future regulatory arrangements which is likely to include greater use of NEM comparators.

288. In its Amended Access Arrangement Information, Western Power is critical of GBA's benchmarking analysis.[73] Western Power believes that GBA has not appropriately recognised and corrected for the differences between Western Power and utilities in other jurisdictions. Western Power also believes that GBA's benchmarking of a single year introduces a bias.

289. During the second round of consultation, the WAMEU noted that, in theory, it would expect that Western Power should have been more efficient in GBA's benchmarking analysis published with the Draft Decision, as it is an aggregated transmission and distribution business and as a result it should have lower overheads. However, the WAMEU noted that GBA's benchmarking analysis showed that Western Power was less efficient for all three normalisers. The WAMEU suggested that, based on GBA's benchmarking results, the efficient boundary would appear to be some 40 per cent less operating expenditure than Western Power spent in the current access arrangement period. The WAMEU noted that, despite Western Power's own benchmarking showing that it was not efficient either currently, or in the future, both GBA and the Authority considered that the base year expenditure was efficient. The WAMEU considers that the Authority builds on an inefficient base operating expenditure.[74]

290. GBA noted that the limitations discussed by Western Power (and its consultant Wedgewood White) are well known and were discussed in its initial report. Due to these known limitations, GBA noted that the findings of its benchmarking analysis informed its review but were not relied on by it in making its recommendations to the Authority. GBA considers that most of the criticisms in the Wedgewood White report provided by Western Power are just as applicable to Western Power's own benchmarking exercise.[75]

291. The Authority understands the limitations with benchmarking and considers that these limitations apply to both Western Power's and GBA's benchmarking. However, it remains of the view that GBA's benchmarking analysis can be used to inform at a high level the comparative performance of Western Power to its peers. As pointed out by the WAMEU, Western Power is significantly less efficient than the most efficient jurisdictions for the respective normaliser. As noted in the Draft Decision, instead of making a global adjustment to the base year operating expenditure on the

72 February 2012, Productivity Commission, *Electricity Network Regulation: Issues Paper*.

73 May 2012, Western Power, Amended Access Arrangement Information, pp. 83-86.

74 June 2012, Western Australian Major Energy Users, Submission to the Economic Regulation Authority, pp. 42 -43.

75 August 2012, Geoff Brown & Associates, *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision*, section 2.7, pp. 10-11.

benchmarking results, the Authority considered that it is appropriate to incentivise Western Power to meet more efficient operating expenditure levels. The specifics of an efficiency adjustment to costs during the third access arrangement period are discussed below at paragraphs 535 to 561.

Line Item Analysis of Base Year Network Operating Expenditure

292. In its review prior to the Draft Decision, GBA undertook a high level review of individual line items included in the base year operating expenditure to identify base year expenditure line items that appeared to be atypical. GBA focussed on particular base year operating expenditure line items where the increase from 2009/10 was particularly large and sought further information from Western Power on the reasons for the increase. The individual base year operating expenditure line items which GBA identified as requiring further review are shown in Table 13 below.

Table 13 Base Year Recurrent Operating Expenditure Specific Line Items Identified by GBA for Further Review (real $ million at 30 June 2012)

Expenditure Item	2009/10	2010/11	Increase to 2010/11	2011/12
Distribution Corrective Maintenance – Emergency Follow-up Overhead Maintenance	3.8	8.4	120%	4.1
Distribution Corrective Deferred – Data Correction	0.9	3.3	267%	1.1
Distribution Preventive Condition – Earthing Maintenance	1.3	2.3	79%	1.7
Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency	4.6	7.1	54%	6.1
Transmission Corrective Deferred – Environmental Cleanup	0.3	1.2	308%	0.9
Transmission Preventative Condition – Plant and Building Refurbishment	0.3	1.4	417%	0.9
Transmission Substation Battery Maintenance and Inspections	1.4	1.7	21%	0.8
Transmission Substation Primary Plant	3.3	4.6	38%	4.9

Source: Geoff Brown & Associates 2012*. Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* www.erawa.com.au, pp. 116-121.

293. The Authority's considerations of each of the items in Table 13 above are set out below.

294. In response to the Draft Decision, Western Power disagreed with the approach taken in the Draft Decision as it considered that amending only individual activities that have increased from the previous year will downwardly bias forecast costs. Western Power considers that this approach does not consider the activities which have decreased during the current access arrangement period. Western Power claims that GBA's

approach ignores the inherently variable nature of individual operating expenditure line items.[76]

295. GBA considers that Western Power's argument overlooks the magnitude of the increase in Western Power's operating expenditure between 2009/10 and the 2010/11 base year. GBA notes that this increase was 11.7 per cent, whereas allowing for growth and inflation an increase of only 5.7 per cent would have been expected.

296. Although the approach used in paragraph 295 is relatively simplistic, the Authority considers that in circumstances where the proposed base year expenditure was more than double a reasonable expected growth rate from the previous year, GBA's approach of assessing the efficiency of the base year in detail is reasonable and justified. The Authority notes that GBA's recommended downward adjustments for the Draft Decision was only 1.2 per cent lower and much less than the 6 per cent downward adjustment which a high level assessment indicated.

Distribution Corrective Maintenance – Emergency Follow-up Overhead Maintenance

297. In preparing its report prior to the Draft Decision, GBA discussed the significant increase in the 'Distribution Corrective Maintenance – Emergency Follow-up Overhead Maintenance' line item for 2010/11 with Western Power. Western Power had noted that the 2009/10 amount was abnormally low due to an unexplained anomaly in the cost capture mechanism which led to work being incorrectly booked to the corrective emergency category. GBA reviewed this expenditure, together with the corrective emergency category, and advised that this appeared to have been the case. As a result, GBA recommended to the Authority that the base year expenditure was reasonable.[77] The Authority considered this to be reasonable in the Draft Decision. Western Power also proposed a step change to this expenditure category which is discussed further below.

Distribution Corrective Deferred – Data Correction

298. In the Draft Decision, it was noted that Western Power appeared to have included a one-off operating expenditure in the 'Distribution Corrective Deferred – Data Correction' line item. As a result, GBA recommended a downward adjustment to the base year of $2.3 million to account for this.[78] The Authority accepted GBA's adjustment as reasonable in its Draft Decision. In its Amended Access Arrangement Information, Western Power has instead reduced base year costs by $1.68 million and then added project specific costs of $1.1 million for each year of the third access arrangement as a one-off operating expenditure item. Western Power has noted that this expenditure is for targeted asset data cleansing projects for switch wires, conductors and underground assets.

299. GBA has reviewed Western Power's revised proposal and considers that this project appears very inefficient as it sees no reason not to integrate this limited targeted program with the more comprehensive field survey data capture project. GBA considers that the integrated approach is unlikely to materially impact the cost of the data capture project. GBA is satisfied the forecast provision in its initial review prior to

76 May 2012, Western Power, Amended Access Arrangement Information, p. 48.

77 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.1, pp. 116-117.

78 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.2, pp. 117-118.

the Draft Decision ($1.0 million) is sufficient to fund Western Power's routine data cleansing requirements during the third access arrangement period. This implies that the downward adjustment to the base year of $2.3 million should remain.

300. The Authority agrees with GBA's recommendation that the $2.3 million adjustment to 'Distribution Corrective Deferred – Data Correction' should remain and that forecast provision should be sufficient to fund Western Power's routine data cleansing requirements. The Authority agrees with GBA that by adopting an integrated program with the more comprehensive field data survey capture project, which GBA noted would be unlikely to materially impact the cost of the data capture project, should be more efficient than operating separate, parallel programs.

Distribution Preventive Condition – Earthing Maintenance

301. In its report prior to the Draft Decision, GBA noted that the decline in expenditure for the 'Distribution Preventive Condition – Earthing Maintenance' from 2010/11 to 2011/12 indicates that there is no need for the significant increase in expenditure in the base year to continue. As a result, GBA recommended an adjustment to revise base year operating expenditure to the 2011/12 level of $1.7 million (a $0.6 million adjustment).[79] The Authority accepted GBA's adjustment as reasonable in its Draft Decision. In its Amended Access Arrangement, Western Power has accepted this adjustment.

Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency

302. In its report prior to the Draft Decision, GBA considered that while expenditure for the 'Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency' is volatile, it is not valid to use the highest expenditure over the previous regulatory period for the scale escalation model. GBA recommended that the average annual expenditure in this category ($5.9 million) should be used as the base year operating expenditure amount. As a result, GBA recommended to the Authority that base year operating expenditure be revised down by $1.2 million.[80] The Authority considered GBA's adjustment to be reasonable in its Draft Decision. Western Power has accepted this adjustment in its Amended Access Arrangement Information.

Transmission Corrective Deferred – Environmental Cleanup

303. In its report prior to the Draft Decision, GBA considered that the 'Transmission Corrective Deferred – Environmental Cleanup' line item should be amended to reflect an annual average of the current regulatory period as it considers this line item is volatile. As a result, GBA recommended that base year operating expenditure be revised down by $0.4 million.[81] The Authority considered GBA's adjustment to be reasonable in its Draft Decision.

304. In its Amended Access Arrangement Information, Western Power has stated that GBA's recommendation in its review prior to the Draft Decision was underpinned by its misunderstanding about the disposal requirements of polychlorinated biphenyl

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79 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.3, pp. 118-119.

80 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.4, p. 119.

81 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.5, p. 120.

(PCB). Western Power states that there was a minimum threshold below which assets contaminated could stay in use until the end-of-life. Western Power expected that the 2010/11 level of PCB disposal will continue throughout the third access arrangement period in line with Western Power's increasing asset replacement program. As a result, Western Power has not reduced the 2010/11 recurrent base year value for environmental cleanup costs.

305. GBA accepts the position of Western Power. However, GBA's proposed provision of $0.8 million is 167 per cent higher than actual expenditure in 2009/10 and is only marginally below the expected 2011/12 expenditure. The Authority considered GBA's adjustment to be reasonable in its Draft Decision. The Authority remains of the view that GBA's recommended provision is reasonable and considers that this has already allowed a significant increase in expenditure and is comparable to Western Power's 2011/12 forecast for this expenditure provided in its Access Arrangement Information.

Transmission Preventative Condition – Plant and Building Refurbishment

306. In its report prior to the Draft Decision, GBA considered that Western Power did not provide a convincing reason why the higher level of expenditure for the 'Transmission Preventative Condition – Plant and Building Refurbishment' line item in 2010/11 should be maintained for the third access arrangement period. As a result, GBA recommended that base year operating expenditure be revised down by $0.5 million to reflect the average annual expenditure over the second access arrangement period ($0.9 million).[82] The Authority considered GBA's adjustment to be reasonable in its Draft Decision. Western Power has accepted GBA's recommended adjustment for this line item in its Amended Access Arrangement Information.

Transmission Substation Battery Maintenance and Inspections' and 'Transmission Substation Primary Plant

307. In its report prior to the Draft Decision, GBA considered that the appropriate 2010/11 operating expenditure for 'Transmission Substation Battery Maintenance and Inspections' and 'Transmission Substation Primary Plant' line items should reflect the average annual expenditure over the current access arrangement period. As a result, GBA recommended that base year operating expenditure should be revised down appropriately (a total of $0.8 million).[83] The Authority considered GBA's adjustment to be reasonable in its Draft Decision.

308. In its Amended Access Arrangement Information, Western Power states the substation battery maintenance and inspections should have been considered in aggregate with transmission substation inspections due to an accounting change. Instead, GBA added expenditure for substation battery maintenance and inspections with substation primary plant. Western Power states that, when the correct expenditure types are added together, expenditure on substation battery maintenance and inspections and transmission substation inspections in 2010/11 is in line with historical expenditure. As a result, Western Power has not amended the 2010/11 recurrent base year value for substation battery maintenance and inspections.

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[82] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.6, pp. 120-121.

[83] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.7, p. 121.

309. GBA noted that the line item 'transmission substation inspections' was not included in the operating expenditure breakdown provided by Western Power, although it was included as activity K1X16 in Western Power's scale escalation model. However, the scale escalation model only gave actual costs for 2010/11 and not the other years of the current access arrangement. As a result, GBA has no way of verifying Western Power's position. GBA considers that even though it may have been more appropriate to use the line item 'secondary equipment maintenance' rather than 'substation primary plant', this would have given a similar result.

310. The Authority considers that given the lack of information provided by Western Power to GBA to allow it to verify Western Power's position, and that even if GBA did not use the 'substation primary plant' line item in assessing 'substation battery maintenance and inspections' it would have arrived at a similar result, the Authority remains of the view that the adjustment in the Draft Decision is appropriate.

Summary

311. In the Draft Decision, for the reasons outlined above, the Authority accepted GBA's recommended adjustments to the base year recurrent network operating expenditure.

Table 14 Authority's Draft Decision Adjustments to Specific Line Items in Base Year Recurrent Network Operating Expenditure (real $ million at 30 June 2012)

Expenditure Item	Western Power's Proposed 2010/11	Adjustment required	Adjusted Cost 2010/11
Distribution Corrective Deferred – Data Correction	3.3	(2.3)	1.0
Distribution Preventive Condition – Earthing Maintenance	2.3	(0.6)	1.7
Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency	7.1	(1.2)	5.9
Transmission Corrective Deferred – Environmental Cleanup	1.2	(0.4)	0.8
Transmission Preventative Condition – Plant and Building Refurbishment	1.4	(0.5)	0.9
Transmission Substation Battery Maintenance and Inspections	1.7	(0.5)	1.2
Transmission Substation Primary Plant	4.6	(0.3)	4.3
Total adjustment to Base operating expenditure		(5.8)	

312. Western Power's proposed recurrent network base year operating expenditure provided to GBA for review prior to the Draft Decision was slightly above the proposed amount in its access arrangement information. For the purposes of the Draft Decision, the proposed recurrent network base year operating expenditure provided to GBA has been reduced by $5.8 million for the line-item adjustments outlined above.

313. Adjustments were also made in the Draft Decision to include costs relating to SCADA and communication, corrective works and efficiencies for bundling fuse pole clearing

with vegetation inspections. Western Power included these costs in "step changes" (see discussion below).

314. The Authority has considered Western Power's response to the Draft Decision and, as discussed above, remains of the view that the adjustments to the base year (2010/11) operating expenditure made in the Draft Decision are justifiable and appropriate. The Authority requires the base year operating expenditure for the specific line items to be adjusted to the amounts in Table 14 in order for the Access Code requirements to be met.

315. In the Draft Decision, the Authority considered the revised base year expenditure of $249.4 million to be a reasonable base upon which to make an assessment of Western Power's proposed operating expenditure for the third access arrangement period.

316. As noted in paragraph x in relation to environment and planning capital expenditure, the Authority now considers that proposed early strategic planning costs should have been included as operating costs rather than capital costs. As a result, the Authority will include $0.8 million per annum to the base operating expenditure reviewed by the Authority's technical consultant.

317. As a result, the Authority has revised the base year expenditure of $249.4 million to $250.2 million for its Final Decision, and considers that this is a reasonable base upon which to make an assessment of Western Power's revised proposed operating expenditure for the third access arrangement period.

Table 15 Final Decision Base Year Recurrent Network Operating Expenditure (real $ million at 30 June 2012)

	2010/11
Western Power initial proposal[84]	252.4
Adjustments for specific line items	(5.8)
Adjustment for SCADA and Communications	0.8
Adjustment for Corrective works	2.3
Adjustment for bundling fuse pole clearing with vegetation inspections efficiencies	(0.3)
Adjustment for early strategic planning costs	0.8
Total	**250.2**

Forecast Increases in Operating Expenditure

318. The method adopted by the Authority to assess Western Power's forecast of operating expenditure has been to consider differences from the level of operating expenditure actually incurred by Western Power in 2010/11 (being the most recent financial year for which detailed information is available), taking account of the adjustments noted in paragraphs 292 to 312 above. In considering differences between the forecast costs for third access arrangement and the adjusted actual costs of 2010/11, the Authority has had regard to the following:

84 Western Power's proposed base given to GBA following the revised access arrangement information indicated a network base operating expenditure of $252.4 million rather than $251.8 million as indicated in Western Power's revised access arrangement information. Base operating expenditure also excludes corporate expenditure.

- step changes in recurrent costs;
- one-off adjustments;
- network and customer growth;
- non-recurrent network costs;
- indirect costs;
- corporate costs;
- input cost escalation; and
- scope for efficiencies.

Step Change Adjustments

319. Step change adjustments are applied where scale escalation of base year expenditure is not a true reflection of the recurrent operating expenditure requirement for Western Power. In its proposed revisions, Western Power adjusted for step changes related to known future changes in practices, functions, obligations and operating environment. Step changes can either be negative, where costs incurred in the base year are no longer expected to be incurred in the future, or positive where recurrent costs that will be incurred in the future were not in the base year expenditure.

320. In its report prior to the Draft Decision, GBA reviewed these adjustments and recommended to the Authority that the additional $0.8 million for SCADA and communications infrastructure and the decrease of $0.3 million for efficiency gains should be incorporated in base year operating expenditure. However, GBA recommended that the $1 million cost for software licences should be treated as a one-off adjustment that occurs in each year of the regulatory period and not subject to scale escalation since this is a fixed cost. GBA considered that the expenditure associated with the amendments to the Metering Code should commence in 2012/13 instead of 2011/12 as proposed by Western Power. This is because the amendments to the Metering Code have yet to be drafted and gazetted and this is more likely to occur in 2012/13. GBA considered the total corrective expenditure for 2010/11 (base year), exclusive of indirect costs, and compared that to an amount with efficient escalation. GBA concluded that an increased amount of $2.3 million, rather than $3 million as proposed by Western Power, applied to the base year operating expenditure was appropriate to ensure a sustainable level of corrective works.[85]

321. In its Draft Decision, the Authority considered the recommendations made by GBA to be reasonable and appropriate and included step adjustments for Western Power of an additional $0.5 million from 2012/13 to increase the number of metering verifications and compliance testing expected from planned changes to the Metering Code.

322. The Authority considered that the following should be adjustments to the base year operating expenditure for modelling purposes:

- an increase of $0.8 million from 2011/12 for expenditure associated with additional SCADA and communications infrastructure;

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85 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.4, pp. 125-126.

- an increase of \$2.3 million, rather than \$3 million as proposed by Western Power, to ensure base year operating expenditure for corrective works represents a sustainable level of works; and
- a decrease of \$0.3 million from 2011/12 to reflect efficiency gains by bundling fuse pole clearing with vegetation inspections and anticipated savings through the fires safe fuses program.

323. The Authority considered the \$1 million increase for software licences should be treated as a one-off adjustment that occurs in each year of the regulatory period, so as to not apply scale escalation to a fixed cost.

324. As a result, the Authority in its Draft Decision made the adjustments to Western Power's proposed step change operating expenditure as shown in Table 16.

Table 16 Draft Decision Forecast Step Changes in Operating Expenditure (real \$ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	5.0	5.0	5.0	5.0	5.0	25.0
Adjustment for SCADA and Communications	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(4.0)
Adjustment for software licences	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(5.0)
Adjustment for Corrective works	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(15.0)
Adjustment for bundling fuse pole clearing with vegetation inspections efficiencies	0.3	0.3	0.3	0.3	0.3	1.5
Total	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**2.6**

325. In its Amended Access Arrangement Information, Western Power has accepted the step changes and one-off adjustment, except for the amount of adjustment to the base year operating expenditure for corrective works. Western Power states that it has applied the same methodology while using the actual proportion of indirect costs in 2012/13 so that the required addition to the base year expenditure is \$2.84 million rather than the \$2.3 million recommended by GBA.

326. GBA was unable to replicate Western Power's analysis which was not included in its Amended Access Arrangement Information. As a result, GBA reworked its previous analysis to remove actual indirect costs and compared that to the efficient cost for corrective works operating expenditure. While the actual and efficient costs for 2010/11 changed, the difference between them (the adjustment amount of \$2.3 million) did not. As a result, GBA recommended that it is reasonable to maintain the \$2.3 million adjustment as provided in the Authority's Draft Decision. The Authority agrees with the revised assessment GBA has made and maintains that the adjustment to the operating expenditure base year amount for corrective works should remain at \$2.3 million.

327. Western Power has proposed a number of new step changes in its operating expenditure in its Amended Access Arrangement Information. These step changes related to the following cost categories:

- Distribution preventative condition – pole maintenance;
- Distribution preventative routine – bundled pole inspections;
- Distribution preventative routine – wood pole testing facility; and

- Transmission preventative routine, preventative condition and corrective emergency – Clean Energy Futures package.

328. Western Power has increased pole maintenance expenditure by $2.3 million a year due to contractor unit rates increasing over and above those previously estimated by Western Power. GBA has had insufficient information to comment on the detail of the validity of Western Power's analysis leading to the $2.3 million additional cost estimate or whether Western Power has made all reasonable efforts to minimise the increase in negotiating with contractors. While GBA considered that Western Power should take responsibility for increased contractor costs relating to uncertainty or work programming and work delays, it recommended to the Authority that the $2.3 million increase is not unreasonable in an environment where the contractors clearly hold the balance of power in rate negotiations. GBA considers that this adjustment should be a step change adjustment rather than an adjustment to base year as indicated by Western Power in its Amended Access Arrangement Information.

329. The Authority considers that Western Power should be responsible for any increase in contractor costs due to risks being borne by the contractors as a result of uncertainty over work programming and work delays. The Authority does not have enough information to determine what amount of the increase this would represent. Rather than adjust this small increase and considering that GBA has advised that this increased amount is not unreasonable, the Authority has decided to incorporate this $2.3 million increase as a step change commencing in 2012/13. The application of an efficiency factor and the incentive properties in regulation should incentivise Western Power to negotiate strongly with these contractors in the future.

330. Western Power has increased bundled pole inspection expenditure by $3.8 million a year to reflect an increase in volumes as a result of its new wood pole management plan and increased contractor unit rates. GBA reviewed this expenditure and noted that it was not clear whether Western Power had also factored in the savings that should result in no longer needing to do dig and drill inspections for below ground pole health as wood poles will now be reinforced as a minimum under the revised wood pole management plan. However, GBA did not propose a reduction to Western Power's revised proposed forecast for this line item because of Western Power's pole maintenance backlog and any surplus in pole inspections could usefully be reallocated to other priority areas within the broader wood pole management effort. GBA considers that this adjustment should be a step change adjustment rather than an adjustment to base year as indicated by Western Power in its Amended Access Arrangement Information.

331. The Authority is mindful that Western Power may not have factored in possible savings to bundled pole inspections, but considers there should be enough public and other stakeholder pressure to ensure that if this $3.8 million a year increase provides Western Power with a surplus amount, then it should use this to spend on its broader wood pole management effort in an efficient manner. The Authority will assess the efficiency of Western Power's operating expenditure for the third access arrangement in establishing forecasts for efficient expenditure in the fourth access arrangement period. As a result, the Authority has included this $3.8 million for bundled pole inspections as a step change from 2012/13.

332. Western Power has included an additional $1.4 million in its revised proposal to help operate and maintain a facility to test failed, ex-service and new poles. GBA recommended that this expenditure forecast to commence in 2012/13 was appropriate. The Authority agrees with GBA's assessment and has incorporated this increase as a step change from 2013/14.

333. Western Power has included an additional $0.1 million per annum in its revised proposal to account for the impact of increased costs in purchasing and replacing SF6 gas to maintain Western Power's transmission switchgear. GBA considers that such an adjustment is reasonable to the extent that the Clean Energy Future package imposes additional operating expenditure. The Authority agrees with GBA's assessment and has incorporated this increase as a step change from 2012/13.

334. The Authority's Final Decision in relation to step changes to operating expenditure is set out in Table 17 below.

Table 17 Final Decision Adjustments to Step Changes in Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**2.6**
Adjustment for Distribution preventative condition – pole maintenance	2.3	2.3	2.3	2.3	2.3	11.5
Distribution preventative routine – bundled pole inspections	3.8	3.8	3.8	3.8	3.8	18.9
Distribution preventative routine – wood pole testing facility	-	1.4	1.4	1.4	1.4	5.6
Transmission preventative routine, preventative condition and corrective emergency – Clean Energy Futures package	0.1	0.1	0.1	0.1	0.1	0.5
Software licence expenditure transferred from one-off adjustments	1.0	1.0	1.0	1.0	1.0	5.0
Final Decision	**7.7**	**9.1**	**9.1**	**9.1**	**9.1**	**44.0**

One-off Adjustments

335. In its initial proposal, Western Power included a one-off adjustment of $5.2 million in 2011/12 and $8.7 million per year over the three year period 2012-15 for transmission line pole inspection and maintenance to address the backlog of pole conditions to ensure safety and compliance outcomes. One-off adjustments are special non-recurring adjustments to recurring operating expenditure line items that are not subject to scale escalation. In its advice to the Authority for the Draft Decision, GBA noted its understanding that this proposed investment was related to additional work required as a result of an EnergySafety Order. GBA considered that the adjustments proposed by Western Power were reasonable.[86] The Authority agreed with GBA's assessment of this expenditure in its Draft Decision and, along with the adjustment noted at paragraph 323, made the adjustment shown in Table 18.

[86] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.5. p. 126.

Table 18 Draft Decision One-off Adjustment Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal[87]	8.7	8.7	8.7	0.0	0.0	26.1
Adjustment for software licences	1.0	1.0	1.0	1.0	1.0	5.0
Draft Decision	**9.7**	**9.7**	**9.7**	**1.0**	**1.0**	**31.1**

336. Following the Draft Decision, GBA has reconsidered its advice in relation to the classification of software licence costs. For the purposes of the Draft Decision, GBA treated it as a one-off adjustment that occurred in each year of the access arrangement period, since software licences are a fixed cost not subject to scale escalation. However, GBA now considers that scale escalation should be applied to this cost to be consistent with its recommended application of an economy of scale adjustment to recurrent expenditure. As noted further below, GBA considers that an economy of scale adjustment is necessary to reflect that fixed costs will not increase as fast as the network increases. Consequently, GBA has advised that, to be consistent with that view, the amount should be transferred to step changes in operating expenditure.

337. The Authority agrees with this view and has adjusted forecast one-off adjustments and step changes accordingly as shown in Table 17 above and Table 19 below. Western Power had accepted the one-off adjustments in the Draft Decision and did not propose any further one-off adjustments.

Table 19 Final Decision One-off Adjustment Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	9.7	9.7	9.7	1.0	1.0	31.1
Software licence expenditure transferred to step change expenditure	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(5.0)
Final Decision	**8.7**	**8.7**	**8.7**	**0.0**	**0.0**	**26.1**

Network and Customer Growth

Scale escalators

338. Western Power proposed in its Access Arrangement Information (September 2011) that its recurrent operating expenditure forecasts for the third access arrangement period be adjusted for a growing network and customer base. Western Power proposed that an average annual network growth escalator be applied to network operations and maintenance activities and an average annual customer growth escalator be applied to call centre and metering activities. Western Power's calculation of the average annual growth rates, along with the actual growth rate from 2007/08 is presented in Table 20.

87 Western Power's proposed base given to GBA following the revised access arrangement information indicated a network base operating expenditure of $252.4 million rather than $251.8 million as indicated in Western Power's revised access arrangement information. Base operating expenditure also excludes corporate expenditure.

Table 20 Western Power's Proposed Customer and Network Growth Escalation Data

	2007/08	2010/11	2016/17	Actual Growth Rate (2007-11)	Forecast Growth Rate (2010-17)
Customer Numbers (No)	937,104	1,006,430	1,162,284	2.41%	2.43%
Network Growth Escalators					
Line (km)	93,032	96,745	104,178	1.31%	1.24%
Distribution Transformers (No)	61,961	64,471	77,443	1.33%	3.10%
Zone Substation (MVA)	6,827	7,602	10,739	3.65%	5.93%
Average Network Growth Escalator				2.10%	3.42%

339. Western Power adopted the parameters used by the AER for measuring distribution network size.[88] Western Power also applied this escalation to its transmission expenditure. GBA advised that any error from applying this parameter to transmission operating expenditure is unlikely to be material.[89] In its Draft Decision, the Authority agreed with GBA's advice and considered that the parameters selected by Western Power were sound.

340. In the Draft Decision, it was noted that Western Power's forecast customer number growth rate was slightly higher than the actual growth rate from 2007/08 to 2010/11. This difference is not material and, as a result, the Authority did not see any justification to deviate from the historic customer growth rate of 2.41 per cent.

341. As highlighted in Table 20, Western Power proposed escalators for the number of distribution transformers and zone substations which were significantly higher than the actual growth rate from 2007/08 to 2010/11. The growth in line length is comparable with the historic growth rate, and the Authority considered that this forecast was reasonable.

342. In its report prior to the Draft Decision, GBA reviewed the drivers of the number of distribution transformers – customer growth and, to a lesser extent, growth in distribution line length. Western Power forecast these drivers to be similar to historic levels. As a result, and with no explanation provided by Western Power for the significant increase in distribution transformers, GBA saw no basis for the acceleration in the annual rate of growth in distribution transformers proposed by Western Power.[90] In the Draft Decision, the Authority accepted GBA's recommendation that there was no basis for an increase in the growth rate above the growth rate between 2007/08 to 2010/11.

343. GBA was unable to reconcile Western Power's forecast of a total of 3,137 MVA of new zone substation transformer capacity with Western Power's network development plan which indicated the addition of only 1,236 MVA over the period of 2010/11 to

88 Western Power noted on p. 135 of its AAI that it used the number of feeders as a parameter. However, Western Power confirmed to GBA that it actually used the number of distribution transformers in its analysis.

89 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 122.

90 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 122.

2016/17.[91] The Authority noted that the implied average annual growth differed from that indicated in the network development plan (2.54 per cent), which was well below Western Power's forecast of 5.93 per cent. This was also significantly lower than the actual growth rate from 2007/08 to 2010/11 (3.65 per cent).

344. In its Draft Decision, the Authority also noted that Western Power had calculated an average annual network growth escalator over the period and used that in its model rather than the actual escalation factor for each year of the forecast period. Using an average rather than actual rate results in the forecast escalation being around $24 million greater than if the actual escalation had been used each year.[92] This arises because the implied forecast growth in assets is biased towards the end of the third access arrangement period. That is, Western Power had escalated the first few years above the implied growth rate in assets, which has a compounding benefit to Western Power.

345. Western Power's initial proposal did not apply a capital expenditure-operating expenditure trade off factor to its scale escalators. A trade-off arises when new assets require less maintenance than older assets. GBA considered an approach suggested by Nuttall Consulting Ltd in a report for the AER, to account for both the scale escalation of forecast asset growth and capital expenditure-operating expenditure trade-off by using actual growth rates for determining the escalation factor, and recommended it to be a pragmatic and sound solution.[93] The rationale is that new assets installed have a 'honeymoon period' during which little maintenance is required. This results in a lag between when assets are installed and when they must be inspected or maintained. In other words, the maintenance effort is driven not so much by the new assets installed but by the assets that were installed during the previous regulatory periods. This supported the GBA recommendation that the use of historic growth rates is appropriate.

346. In line with the discussion above, in its Draft Decision the Authority considered that the appropriate increase in the network growth escalator was 2.1 per cent. As the Authority did not accept Western Power's forecast growth rates, and has replaced them with its own assessment based on historical data, the overstatement noted in paragraph 344 has been removed.

347. In its response to the Draft Decision, Western Power has not accepted the Authority's amended scale escalation and argues that the network size scale escalator should be based on forecast growth rather than historic growth. It also rejects the concept of a capital expenditure-operating expenditure trade off and listed the issues of 'infant mortality' and the 'bathtub curve' to support this position. Western Power has agreed with the Authority's finding in the Draft Decision that applying an annual average growth rate has distorted the escalation of operating expenditure forecasts in earlier years as the majority of the growth is towards the end of the third access arrangement period. As a result, Western Power is now proposing to use an annual growth rate for each year. Western Power has extended this to apply a specific growth rate to transmission and distribution rather than a combined growth rate.

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[91] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 123.

[92] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*,Section 10.4.1. p. 123..

[93] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 123.

348. GBA has assessed Western Power's revised scale escalation rates and advises that Western Power's derivations of its scale escalators is not sufficiently robust to be relied on for the purposes of setting operating expenditure forecasts. GBA noted that Western Power has increased its proposed forecast growth rate for three of the five scale escalators from its initial proposal despite the reduction in 2016/17 peak demand. Even those proposed escalators that were reduced, declined by much less than the forecast reduction in the rate of growth in demand. GBA also noted that Western Power expected the trend of lower than expected customer number growth over the past two years to be reversed during the third access arrangement period despite the present economic outlook, both internationally and within Australia (particularly outside of the mining sector). GBA also was unable to reconcile Western Power's transmission line length forecast with the limited number of transmission line construction projects during the third access arrangement period.

349. While GBA has not proposed a reduction to the scale escalation factors of 2.1 per cent and 2.41 per cent that it recommended prior to the Draft Decision, it does highlight that the growth rate in peak demand from 2012 (based on the 2010 Annual Planning Report) to 2017 (based on the 2011 Annual Planning Report) represents only 1.1 per cent. GBA remains of the view that using the historical scale escalation factors of 2.41 per cent for customer growth and 2.1 per cent for the network growth escalator is reasonable to cater for Western Power's unavoidable network augmentation requirements and also to provide a reasonable buffer to allow Western Power to improve its existing level of supply security to deal with unexpected circumstances.

350. The Authority agrees with the advice of GBA and considers that, while there is an argument (based on GBA's analysis) that it could reduce the escalation factors adopted in the Draft Decision, it has decided to remain with the escalation factors of 2.41 per cent for customer growth and 2.1 per cent for the network growth escalator for this decision.

Economy of scale

351. The scale escalation described above in paragraphs 338 to 350 reflects the increases in operating expenditure as a result of growth in the network. However, growth in the network should result in economies of scale, that is, lower total costs as a proportion of customers or energy demand or energy usage. Western Power did not include any provision for an economy of scale adjustment to modelling scale escalation in its initial proposal. An economy of scale adjustment is an acknowledgement that, as the network increases, the fixed component of operating expenditure will also increase, but at a different rate. By not including an economy of scale adjustment, Western Power assumes that fixed costs will increase at the same rate as the network grows, which is an assumption that the Authority does not agree with. The AER has generally required provision for an economy of scale factor to be applied to operating expenditure forecasts using a scale escalation approach under which a higher percentage corresponds with a higher proportion of variable costs.

352. In its report prior to the Draft Decision, GBA reviewed past AER decisions on the appropriate factors, particularly for Powerlink and ETSA Utilities which used the same approach taken by Western Power to estimate its scale escalation model. GBA also took into account that Western Power operates an integrated transmission and distribution network. GBA considered that a factor of 30 per cent for network

operations and 95 per cent for other costs was appropriate for Western Power.[94] The economies of scale factors are applied to the scale escalation to determine net escalation, discussed in paragraph 358. The lower the economies of scale factor (which would indicate a higher fixed to variable ratio), the lower the escalation applied to operating expenditure. In its Draft Decision, the Authority considered that these economy of scale factors were reasonable estimates to be applied to Western Power's escalation model.

353. In its Amended Access Arrangement Information, Western Power does not accept that it is reasonable to include an economy of scale factor in its scale escalation model. Western Power believes that the Authority's approach to economies of scale was inconsistent with GBA's benchmarking in the Draft Decision. Western Power considers that if the benchmarking holds, and the relationship between operating expenditure and the normalisers (asset base, network length and customer numbers) is linear, then there can be no economies of scale. Western Power also considers that its base operating expenditure includes scale economies achieved to date and that it may experience diseconomies in the third access arrangement period. Western Power states that the AER's economies of scale adjustment has not been universally applied where scale escalation was applied; the AER's economies of scale adjustment has not been applied with an across-the-board efficiency dividend; and the Authority must have regard to Western Power's specific circumstances.

354. GBA notes that Western Power has applied its benchmarking analysis, which was used to examine Western Power's claim that its costs were comparable with other service providers in Australia, to the discussion on economies of scale. GBA notes that benchmarking is a commonly used tool in regulatory economics and that the normalisers it used are generally accepted and used within the industry. GBA also considers that the AER does not appear to share Western Power's view that these normalisers are incompatible with the application of economies of scale. GBA notes that the AER requires economy of scale factors to be incorporated into operating expenditure forecasts developed using a scale escalation model. GBA highlights that Western Power's claim that the AER has not universally applied economy of scale factors where escalation was applied is incorrect for recent electricity network reviews.[95]

355. GBA advises that Western Power appears to be suggesting that it has already captured all available economies of scale. GBA disagrees with this view and notes that the AER is still requiring economy of scale factors in regulatory decisions on electricity networks even though the application of incentive based regulation is significantly more mature in the NEM than in Western Australia. GBA considers that Western Power has not provided any substantive or objective analysis comparing the age or condition of its network with that of other network service providers. As a result of the consideration above, GBA recommends that the use of economies of scale and the magnitudes in its report prior to the Draft Decision are not inappropriate.

356. The Authority has reviewed recent AER determinations in relation to electricity network providers, including Transend, and notes that economies of scale have been applied in all cases. The Authority agrees with the advice of GBA that it is reasonable

94 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.2. pp. 123-124.

95 August 2012, Geoff Brown & Associates 2012, *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision,* Section 3.4.2.2, p. 22.

to apply economy of scale factors and that the magnitudes adopted in the Draft Decision should remain. The economy of scale factors are shown in Table 21.

357. The Authority notes Western Power's comment that the AER has not applied an economy of scale factor in conjunction with an 'across the board' efficiency dividend. However, the Authority considers that the two issues are separate. Going forward, Western Power's operating expenditure should reflect the fact that not all of its costs will grow as fast as the network growth rate as there is a proportion of fixed costs. However, as detailed in the discussion on an efficiency adjustment further below, the Authority considers that Western Power is not currently as efficient as relevant peers in the industry. As a result, Western Power needs to improve towards these levels and become more efficient.

Amended scale escalation

358. In the Draft Decision, taking account of the considerations outlined above regarding the appropriate growth escalators and economy of scale factors, the Authority determined the net growth escalators to operating expenditure to be as shown in Table 21 below. For the reasons outlined above, the Authority has not changed its view for the Final Decision.

Table 21 Draft and Final Decision - Scale Escalators to be applied to Western Power's Recurrent Expenditure (per cent per annum)

	Growth	Economy of Scale	Net Growth
Distribution			
Network Operations	2.10	30	0.63
Reliability	2.10	95	2.00
SCADA and Communications	2.10	95	2.00
Maintenance – Corrective Deferred	2.10	95	2.00
Maintenance – Corrective Emergency	2.10	95	2.00
Maintenance – Preventative Condition	2.10	95	2.00
Maintenance – Preventative Routine	2.10	95	2.00
Call Centre	2.41	95	2.33
Metering	2.41	95	2.33
Transmission			
Network Operations	2.10	30	0.63
SCADA and Communications	2.10	95	2.00
Maintenance – Corrective Deferred	2.10	95	2.00
Maintenance – Corrective Emergency	2.10	95	2.00
Maintenance – Preventative Condition	2.10	95	2.00
Maintenance – Preventative Routine	2.10	95	2.00

359. The Authority has applied the net growth escalators to operating expenditure to determine the amount of scale escalation to be included in operating expenditure, as shown in Table 22 below.

360. The Final Decision is slightly higher than the amount calculated at the time of the Draft Decision due to changes in operating expenditure forecasts.

Table 22 Final Decision Scale Escalation Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	17.7	27.1	36.9	46.9	57.0	185.6
Draft Decision	9.6	14.5	19.6	24.7	30.0	98.4
Western Power revised proposal	13.2	18.5	28.3	37.1	52.6	149.6
Final Decision	**9.6**	**14.7**	**19.9**	**25.2**	**30.6**	**100.1**

Non-recurrent Network Operating Expenditure

361. Western Power's initial proposal forecast non-recurrent operating expenditure in its total forecast operating expenditure, as shown in Table 23. Non-recurrent operating expenditure includes activities that are one-off, project based or for a discrete time period. Western Power has not applied scale escalation to these costs.

Table 23 Western Power's Initial Proposed Forecast of Non-recurrent Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Smart Grid	4.3	3.5	4.2	5.5	6.7	24.3
Distribution – Field Survey Data Capture Project	5.6	7.2	7.2	7.1	7.2	34.3
Distribution – Network Control Expenditure	2.3	2.3	2.3	2.3	2.4	11.7
Distribution – Distribution Quotations	4.1	4.2	4.3	4.3	4.3	21.2
Distribution – GSL Payments	2.5	2.9	3.2	3.5	3.8	15.9
Distribution – Total	**18.8**	**20.1**	**21.2**	**22.7**	**20.6**	**107.5**
Transmission – Network Control Expenditure	10.8	4.5	9.4	12.1	17.7	54.5
Transmission – Transmission Line Decommissioning	2.9	2.4	0.7	0.6	-	6.6
Transmission – Total	**13.7**	**6.9**	**10.1**	**12.7**	**17.7**	**61.1**
Total non-recurrent operating costs	**32.5**	**27.0**	**31.3**	**35.4**	**38.3**	**168.6**
Non-revenue Cap Services						**90.2**
Indirect Costs included in line items above						**(34.4)**
Western Power's Non-recurrent Network Costs	**42.9**	**38.6**	**42.9**	**47.0**	**52.9**	**224.4**

Source: Western Power's response to GBA and Authority questions.

362. Each of the items in Table 23 is considered below.

Smart Grid

363. In its initial proposal, Western Power included $24.3 million in operating costs for its smart grid program. The Authority received many submissions during the first round of public consultation in support of Western Power's proposed program.[96] The exceptions to this were opposing submissions received from Synergy[97] and the Office of Energy[98]. Regardless of the level of support from interested parties, the Authority considers the investment should only be allowed if the benefits outweigh the costs. Western Power's forecast benefits include increased energy efficiency and the ability to "shift" load away from time of peak consumption which should increase the load factor and reduce the need for peaking generation. Most of the forecast benefits will accrue to customers through lower wholesale prices. In its report prior to the Draft Decision, GBA advised that the operating expenditure proposed by Western Power was reasonable.

364. Nevertheless, GBA noted that it could be argued that the financial benefits to stakeholders of smart grid implementation have yet to be validated despite various trials and large scale roll outs in Australia. In the Draft Decision, the Authority noted that smart metering infrastructure has attracted criticism in Australia, particularly in relation to price rises resulting from the adoption of the technology. The Victorian advanced metering infrastructure program, in particular, has been quite contentious. GBA noted that Western Power appears to have learnt some of the lessons from the Victorian experience. The Authority notes that Western Power has forecast an NPV increase of $133 million in distribution operating expenditure despite field service savings (reduced meter reading etc) of $64 million over a 20 year horizon.

365. However, the Authority has considered the whole smart grid capital expenditure and operating expenditure program together and while speculative, benefits are estimated by Western Power to exceed costs by $208 million. The Authority has considered the capital expenditure amount for smart grid in paragraphs 961 to 964.

366. GBA advised that, given Western Power's unique situation, where it has the ability to leverage the replacement of 280,000 three phase meters, the smart grid deployment proposed by Western Power for the third access arrangement period is more likely than most to realise net stakeholder benefits over time. GBA noted that Western Power provided a very thorough analysis of potential benefits arising out of its proposed smart grid program and, while various modelling assumptions could be debated, the overall program does appear to offer a potentially promising net benefit to stakeholders. GBA considered that Western Power has been rigorous in forecasting the costs of the program and notes that it is proposing a relatively strong investment in consumer education in an attempt to ensure that the wider stakeholder benefits are actually realised.[99]

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[96] Goldfields-Esperance Development Commission, Lend Lease, Synergy, TPE Services, Mr Martin Anda, Verdant Vision, Denmark Community Windfarm Ltd, Silver Springs Networks Inc, Professor Peter Wolfs, Mr David Bryant, Sustainable Energy Now Inc, Professor Syed Islam, Sustainable Energy Association of Australia Inc, LandCorp, Mr Andrew Went, Water Corporation.

[97] November 2011, Synergy, *Public Submission to the Economic Regulation Authority – Western Power's Proposed Revisions to the Access Arrangement.*

[98] December 2011, Office of Energy, *Public Submission on the Issues Paper on Western Power's Proposed Amendments to its Access Arrangement for the Third Regulatory Period.*

[99] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.1, p. 127, Section 8.9, p. 104.

367. The Authority noted in the Draft Decision that, while the additional expenditure is not entirely for the benefit of the distribution system, the new facilities investment test takes account of benefits to all those who generate, transport and consume electricity. The benefits identified by Western Power in relation to the smart grid program will accrue to such parties and, therefore, are reasonably expected to meet the requirements of the new facilities investment test. As a result, in the Draft Decision, the Authority accepted Western Power's proposal. However, as the Authority considers that these benefits are yet to be demonstrated, it will expect further information from Western Power on the realised benefits during the third access arrangement period to support any future proposals for additional expenditure in relation to extending the smart grid in the fourth access arrangement review or beyond.

Field survey data capture project

368. Western Power initially proposed that an amount of $34.3 million over the third access arrangement period is required to be spent on its field survey data capture project. This project is a continuation of a pilot project that was implemented in the current access arrangement. The project involves a complete survey of Western Power's transmission and distribution line assets and is aimed at addressing significant data quality issues.

369. In its report prior to the Draft Decision, GBA was unconvinced that the quality of the existing data set has deteriorated to the extent that the most extensive project of its kind ever undertaken in Australia is now required. GBA considered that a more targeted approach to fix areas where data is known to be poor should be considered by Western Power. GBA also noted that it would have expected Western Power's pilot project to have led to implementation efficiency gains but the extent to which such gains have been incorporated into its forecast expenditure is limited.[100]

370. As a result, GBA advised that half of the proposed expenditure should be sufficient. However, GBA noted that if Western Power considers this amount to be insufficient, it should provide additional information following the Authority's Draft Decision.[101]

371. The Authority noted in the Draft Decision that it was concerned that Western Power's asset data is not of a high standard particularly because Western Power is using this asset data set in some respects to set its expenditure forecasts. However, the Authority agreed that a more targeted approach of addressing areas where data is known to be poor should be considered by Western Power. As a result, and consistent with the requirement of section 6.40 of the Access Code that only non-capital costs incurred by a service provider efficiently minimising costs should be included in approved non-capital costs, the Authority considers that 50 per cent of Western Power's proposed expenditure, is an appropriate forecast for distribution expenditure on the field survey data capture project. The Authority noted that, if Western Power considered this amount to be insufficient, it would need to provide further justification to the Authority on why higher cost alternatives are required.

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[100] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section B5.5 p. B16.

[101] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.2.1, pp. 127-128.

372. In its response to the Draft Decision, Western Power has maintained its view that the project, as proposed in its initial submission, is required and does not consider the forecast expenditure can be reduced.

373. GBA has reviewed Western Power's response and notes that the business case provided by Western Power as a confidential appendix to the amended access arrangement information gives virtually no consideration to alternative options and focuses on justifying Western Power's preferred alternative as being the only acceptable solution. In its report prior to the Draft Decision, GBA notes that it raised concerns about the quality of some of Western Power's business cases it has seen.

374. GBA made the following observations on Western Power's comments on the field survey data capture project in its Amended Access Arrangement Information:[102]

- GBA considers there is still a significant sum sufficient to fund a project either comparable to or larger than three of the four comparator projects identified in Western Power's "business case";
- GBA notes that Western Power provided comments that peer service providers in Eastern Australia have large scale data capture activities either planned or underway but provided no proof that this was the case;
- GBA considers the real issue that should determine the scope of the data capture project is the condition of the existing database and Western Power has not provided quantitative analysis on the number of pilot programs it has undertaken. GBA notes that instead it has relied on adverse comments by EnergySafety and the Parliamentary Standing Committee as well as selected examples (which may well be atypical) to support its case;
- GBA believes a more balanced view on the condition of Western Power's existing database is provided in GHD's asset management audit report which indicated that timely recording of data changes was a more serious problem.

375. GBA considered that a possible alternative option which was not considered by Western Power would be to give pole inspection contractors copies of asset records and require them to assess, as part of the inspection process, whether or not the record on an individual asset is fit for purpose. GBA considered that such an approach could provide a data set that was fit for purpose after one inspection cycle at a much lower cost than currently proposed because data on assets with records of sufficient accuracy would not be recaptured. GBA noted that 'if this process was put in place permanently it would become a feature of Western Power's asset data maintenance strategy and go some way to addressing what appears to be a significant gap in its current and proposed procedures.'[103] GBA also noted that this alternative approach should also find missing poles, provided that the inspectors worked systematically through the network.

376. GBA recognises that the 50 per cent reduction it has proposed is an estimate only due to a lack of information to be able to establish an optimum project scope. GBA considers Western Power should reanalyse the project objectively. GBA notes that it may find that the benefits it really needs could be captured at an even lower cost than proposed by GBA, in which case the savings will be magnified through the gain

[102] August 2012, Geoff Brown & Associates, *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision,* Section 3.5.1, pp. 24-25.

[103] August 2012, Geoff Brown & Associates, *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision,* Section 3.5.1, p. 26.

sharing mechanism. Alternatively, Western Power may find that a higher scoped project would provide value, albeit that it would cost more than the cost proposed by GBA. If that is the case, then the benefit-cost ratio will be greater than 1 and Western Power should proceed with a more extensive project and fund the additional cost from the benefits it provides. GBA also highlights that Western Power should consider the development of robust procedures to ensure that captured data is properly maintained as part of the project design, and not leave this until after the data collection project is finished or even well underway.

377. The Authority agrees with the points made by GBA. The Authority does not consider the additional information provided by Western Power provides sufficient justification to increase the forecast amount included in the Authority's Draft Decision. Consequently, in its Final Decision, the Authority has not amended the forecast from the Draft Decision as set out in Table 24 below.

Table 24 Final Decision Forecast Field Survey Data Capture Project Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	5.6	7.2	7.2	7.1	7.2	34.3
Draft Decision	2.8	3.6	3.6	3.6	3.6	17.2
Final Decision	**2.8**	**3.6**	**3.6**	**3.6**	**3.6**	**17.2**

Network control expenditure

378. In its initial proposal, Western Power included $66.2 million for network control expenditure ($11.7 million on the distribution network and $54.5 million on the transmission network). Network control services are payments made to generators to operate at times of peak demand as a means to defer the need for capital expenditure in areas of network constraint. Western Power's targeted areas for network control services include Ravensthorpe and Bremer Bay on the distribution network and Albany, Geraldton, Eastern Goldfields and Pinjar on the transmission network.

379. In its report prior to the Draft Decision, GBA assessed Western Power's expenditure on these network control services and noted that the uncertainties involved in forecasting these costs were much higher than other operating cost line items. This is due to the uncertainty of the cost of generation at the necessary time and the actual requirement for network control services given the actual demand for electricity.

380. However, as noted by GBA, this forecasting risk appears to fall entirely on customers, as Western Power can treat any under-expenditure as an efficiency gain and carry it forward into the fourth access arrangement period (as it is subject to the gain sharing mechanism) and for any over-expenditure, Western Power has indicated that it will seek to recover these costs under section 6.76 of the Access Code.[104]

381. In the Draft Decision, the Authority took the view that this approach was unreasonable as the forecasting risk falls asymmetrically. The Authority acknowledged that if there is a sound business case for this expenditure to defer capital expenditure, then it would be prudent for Western Power to undertake this expenditure. The Authority considered that no allowance should be included for network control services in

104 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.7.1, pp. 130-131.

forecast operating expenditure as it was not satisfied that it meets the test in section 6.40 of the Access Code and that Western Power should seek to recover any efficient operating expenditure it incurs on network control services through section 6.76 of the Access Code.

382. As a result, in the Draft Decision the Authority required Western Power to remove the costs relating to network control services on the basis that such costs, to the extent that they could be demonstrated to be efficient, could be recovered through section 6.76 of the Access Code.

383. In response to the Draft Decision, Western Power submitted that it would not be able to recover its costs in the manner proposed by the Authority as section 6.76 of the Access Code does not allow for retrospective recovery of actual costs. The Authority has given further consideration to the operation of section 6.76 in paragraphs 2266 to 2268 and accepts that Western Power is correct in its view that it does not allow for retrospective recovery of actual costs.

384. Western Power has also proposed to amend the gain sharing mechanism to exclude network control services. Western Power recognises the Authority's concern that including network control services in the forecast against which the gain sharing mechanism is assessed may result in a windfall gain where it is determined that it is more efficient to reduce, or not pursue, this option. The Authority considers this proposal partially meets its concerns but Western Power would still potentially benefit from a windfall gain during the access arrangement period as there is no mechanism to adjust for any underspend of operating expenditure.

385. In its submission in response to the Draft Decision, the Shire of Ravensthorpe expressed concern that the Authority's decision to exclude network control costs from target revenue has resulted in Western Power not proceeding with the Ravensthorpe Islanding projects.

386. The Authority notes advice from its technical adviser that Western Power has not amended its operating cost forecast since its initial proposal to reflect the lower peak demand and energy sales in the 2011 APR.[105] GBA advises that a downward adjustment would be appropriate as lower energy sales would reduce the running time of network control service generation, resulting in lower fuel and maintenance costs.

387. The Authority recognises that network control services are a cost effective way of deferring grid augmentations, particularly on fringe areas of the network, where loads tend to be relatively low and the cost of network augmentation is high because of the distances involved. The Authority also recognises that a regulatory framework that favoured grid augmentation over network control services could result in perverse outcomes.

388. The Authority notes that the current access arrangement includes a D-factor scheme which enables Western Power to fully recover, in the next access arrangement period, operating expenditure that is incurred by Western Power as a result of deferring a capital expenditure project or in relation to demand-management initiatives. The D-factor scheme seeks to address the disincentive to implement non-network alternatives to capital projects in resolving network constraints.

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105 August 2012, Geoff Brown & Associates 2012, *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision,* Section 3.5.2, p. 27.

389. The Authority considers the factors driving consideration of network control services are similar to the type of expenditure already covered by the D-factor scheme. Consequently, the Authority considers that expanding the D-factor scheme to incorporate network control services would provide certainty to Western Power that it will be able to recover the costs of all efficiently incurred network control services, and ensure that only efficient investment decisions are made. The Authority considers that these measures should ensure that network control services are used where that is the most efficient option, and therefore schemes such as the Ravensthorpe Islanding would proceed assuming it is efficient.

390. The Authority therefore requires that network control services be excluded from operating costs for the purposes of determining target revenue and the D-factor scheme should be modified to include network control services.

Required Amendment 4

Network control services must be excluded from operating cost forecasts for the purposes of determining target revenue and the D-factor scheme must be modified to include network control services.

Table 25 Final Decision Forecast Network Control Expenditure Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution Network Control Services						
Western Power initial proposal	2.3	2.3	2.3	2.3	2.4	11.7
Draft Decision	0.0	0.0	0.0	0.0	0.0	0.0
Final Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Transmission Network Control Services						
Western Power initial proposal	10.8	4.5	9.4	12.1	17.7	54.5
Draft Decision	0.0	0.0	0.0	0.0	0.0	0.0
Final Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Distribution Quotations

391. In its initial proposal, Western Power included $21.3 million for quotations on the distribution network. This expenditure is for the design and estimation of customer connection to the distribution network. It is customer-driven expenditure largely outside the control of Western Power. GBA recommended that the amount forecast by Western Power be accepted as the forecast requirement is lower than the average actual expenditure during the current access arrangement period.[106] In the Draft Decision, the Authority acknowledged that this expenditure is largely outside of

[106] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.3, pp. 128-129.

Western Power's control and, with expenditure below the average actual from the current access arrangement period and without any information to challenge the reasonableness of this forecast, it decided to accept Western Power's forecast. The Authority has not altered its view in the Final Decision.

GSL Payments

392. Western Power's initial proposal included $15.9 million for payments it is required to make under Part 3 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (**NQ&RS Code**). These payments are referred to as guaranteed service level payments (**GSL**). The payments relate to two quality of supply issues: non-notification of planned outages and extended outages.

393. In the Draft Decision, the Authority acknowledged that Western Power is required by the NQ&RS Code to make guaranteed service level payments. However, the Authority considered that the payment relating to provision of notice for planned outages is fully within the control of Western Power's management and should not be borne by customers. Also, the Authority noted that Western Power actually pays more per instance of non-notification ($50) than legally prescribed ($20). As a result, the Authority required Western Power to remove the amount for non-notification of planned interruptions.

394. In its initial proposal, Western Power forecast that the number of eligible customers for payments for extended outages (outages lasting longer than 12 hours) will increase significantly from 64,208 in 2010/11 to 180,521 by 2016/17. GBA noted that this is in spite of Western Power introducing a new $41.4 million capital expenditure program in the third access arrangement period to address the causes of extended supply interruptions. As a result, GBA recommended that a more reasonable forecast would be to maintain the number of eligible customers at the 2010/11 amount. GBA applied this to an average application rate of 30 per cent (not all eligible customers actually apply, with the application rate varying from 11 per cent to 37 per cent during the period 2006/07 to 2010/11). GBA has also suggested that a provision of 10 per cent of the determined requirement ($1.55 million based on the number of affected customers multiplied by the application rate and payment rate of $80) be allowed to fund additional payments for severe storms.[107] GBA suggested the allowance for severe storms, e.g. for severe storm events similar to the event which occurred in March 2010, be included as Western Power's ability to mitigate the impact of these severe storms is limited. The number of customers eligible for 2010/11 payments did not include the impact from the severe storm on 22 March 2010.

395. In the Draft Decision, the Authority considered that the forecasts calculated by GBA would reasonably reflect the efficient costs for GSL payments and as a result, required that Western Power's operating expenditure be adjusted according to the amounts set out in Table 26.

Table 26 Draft Decision Forecast GSL Payment Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	2.5	2.9	3.2	3.5	3.8	15.9
Draft Decision	**1.7**	**1.7**	**1.7**	**1.7**	**1.7**	**8.5**

107 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.4, pp. 129-130.

396. In response to the Draft Decision, Western Power accepted the Authority's required amendments in relation to GSL payments and revised its forecasts accordingly.

Transmission Line Decommissioning and Removal

397. In its initial proposal, Western Power included $6.6 million for the removal of approximately 60km of overhead line. In its advice for the Draft Decision, GBA compared this proposed expenditure with the forecast decommissioning and removal costs of the existing 132 kV 190km long line between Pinjar and Eneabba as part of the Mid West Energy Project. The estimate for this cost is $6.01 million in real 30 June 2012 dollars. This estimate was only slightly below what Western Power is now forecasting for the removal of only 60km of line. GBA advised that a revised estimate of $2.1 million during the third access arrangement period was a reasonable estimate, taking into account Western Power's forecast removal costs for the 190km line between Pinjar and Eneabba and adding a 20 per cent margin to cover costs that may not be adequately provided for in a simple pro rata analysis. GBA's recommended forecast also excluded real cost escalation.[108]

398. In the Draft Decision, the Authority considered that the revised forecasts determined by GBA would reasonably reflect the efficient costs for transmission line decommissioning and removal, rather than what appeared to be an excessive estimate provided by Western Power. As a result, the Authority required that Western Power's operating expenditure be adjusted in Table 27.

399. In response to the Draft Decision, Western Power submitted that it is not appropriate to use the Mid West Energy Project as a benchmark.

400. GBA agrees with Western Power to the extent that, if the Mid West Energy Project is used as a benchmark for estimating its required expenditure for transmission line removal, an adjustment is appropriate to take account of different factors. However, it notes that its recommended estimate of the costs included such an adjustment. GBA notes that its recommended adjustment added approximately 20 per cent to the costs of the Mid West Energy Project, whereas Western Power was proposing an adjustment almost 10 times that amount.

401. For the reasons set out above, the Authority has maintained the same forecast in the Final Decision as set out in Table 27 below. The Authority notes that, since the Draft Decision, Western Power has revised its expenditure proposal and has reduced its forecast expenditure to $2.9 million.

Table 27 Final Decision Forecast Transmission Line Decommissioning and Removal Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	2.9	2.4	0.7	0.6	-	6.6
Draft Decision	1.0	0.8	0.2	0.2	-	2.2
Final Decision	**1.0**	**0.8**	**0.2**	**0.2**	**-**	**2.2**

108 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.7.2, pp. 131-132.

Summary of Non-recurrent Network Operating Expenditure

402. Table 28 below summarises the Authority's draft decision in relation to non-recurrent network operating expenditure taking account of all the matters discussed above. In addition, the Authority excluded operating expenditure for non-revenue cap services from total operating expenditure. This approach has the same net result as Western Power's proposal which includes non-revenue cap operating expenditure in total operating expenditure and then deducts the same amount from revenue cap target revenue. In the Draft Decision the Authority took the view that excluding non revenue cap operating expenditure from the total operating expenditure forecast used to calculate target revenue is a simpler and preferable approach.

Table 28 Draft Decision Forecast Non-recurrent Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Smart Grid	4.3	3.5	4.2	5.5	6.7	24.3
Distribution – Field Survey Data Capture Project	2.8	3.6	3.6	3.6	3.6	17.2
Distribution – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Distribution – Distribution Quotations	4.2	4.2	4.3	4.3	4.3	21.2
Distribution – GSL Payments	1.7	1.7	1.7	1.7	1.7	8.5
Distribution – Total	**12.9**	**13.0**	**13.8**	**15.1**	**16.4**	**71.3**
Transmission – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Transmission – Transmission Line Decommissioning	1.0	0.8	0.2	0.2	-	2.2
Transmission – Total	**1.0**	**0.8**	**0.2**	**0.2**	**0.0**	**2.2**
Total non-recurrent operating costs	**14.0**	**13.8**	**14.0**	**15.3**	**16.4**	**73.5**

403. Western Power's response to the Draft Decision is discussed in paragraphs 361 to 401 above. In addition, Western Power raised three new items it considered should be included in non-recurrent network costs. These are:

- compliance with "Type 1 obligations" under the Code of Conduct for the Supply of Electricity to Small Use Customers[109];
- acceleration and change in capitalisation treatment of the streetlight switchwire program; and
- the Australian Government's Clean Energy Future package

404. Each of these is considered below.

[109] Type 1 obligations impose requirements on Western Power relating to the times during which a customer may be disconnected for non-payment, non-disconnection of customers that rely on electricity for life support and the provision of notice of planned outages to affected life support customers amongst other requirements.

Compliance with Type 1 Obligations

405. Western Power's Amended Access Arrangement Information has incorporated an amount of $29 million in its operating expenditure forecasts to improve its compliance with Type 1 obligations under the *Code of Conduct for the Supply of Small Use Customers* (**Customer Code**). The Authority has published four notices outlining a total of six contraventions of Western Power's Type 1 obligations since June 2011.

406. Western Power's planned expenditure to improve its performance to meet Type 1 obligations includes:

- establishing a dedicated team to improve the management of life support equipment data and outage notifications, including a field visit process to validate new life saving equipment installed and ensuring that each customer with life support is notified in person of planned outages;
- creating a dedicated team of seven people to independently review and have control over all distribution access requests and introduce real time system access for Western Power's switching operators; and
- introduce a real-time 24x7 central management to allow for improved monitoring and reporting in the low voltage network. This will include the creation of three day control desks and one night control desk, requiring 14 controllers and three system support personnel.

407. GBA reviewed Western Power's planned expenditure to improve compliance with Type 1 obligations of the Customer Code and did not support Western Power's planned expenditure. GBA noted that Western Power had contravened its obligations under the Customer Code multiple times but believed Western Power was making a significant improvement in its performance. GBA reviewed the Authority's notices on this issue and GBA considered that the successive notices actually indicate a progressive and significant improvement in performance to the extent that GBA believes the Authority's concerns now appear to have been addressed. GBA noted that the last contravention notice reflected that this matter was being taken very seriously with an employee of a contractor being dismissed in connection with the contravention.

408. GBA advised that there was insufficient evidence that the employment of 21 additional staff at a cost of $29 million during the third access arrangement was necessary to prevent a reoccurrence of Type 1 problems, which GBA noted appeared to have been largely addressed.

409. The Authority notes that it has not come to a view on whether Western Power's response to the contraventions of Type 1 obligations has addressed its concerns. The Authority in its notices on this matter has merely noted the actions taken by Western Power to address the issues that have caused the contraventions of the Type 1 obligations. On the last contravention, Western Power did not have in place adequate controls when planned outage work was undertaken by external contractors. The Authority is of the view that the effectiveness of the actions taken by Western Power to improve the management of outages undertaken by external contractors will be examined in the next performance audit of the Western Power licence.

410. The Authority is of the view that Western Power's proposal to undertake field visits to validate equipment installed at customer premises falls outside its remit and is the responsibility of the retailer. Part 7.7 of the Code of Conduct requires a retailer to

register a customer address as a life support equipment address (LSEA), subject to the customer providing the retailer with confirmation from an appropriately qualified medical practitioner that the person residing at that address requires life support equipment. The retailer is required to notify the distributor that the address has been registered as a LSEA so that the distributor registers the address as a LSEA in their records. This is to remain in place until the person requiring life support equipment vacates the address or the person no longer requires the life support equipment. As it is the retailer who has the relationship with the customers, the Authority considers it reasonable that the interface with the customer in respect of life support equipment rests with the retailer rather than the distributor.

411. The Authority considers that it is inefficient for Western Power to have a dedicated team visiting customers to notify life support customers of a power outage when what is required is a set of robust processes to ensure that the customer is informed of planned outages by mail and telephone using the existing resources at its disposal. If a visit to a LSEA is required then it should be possible to assign this task to existing field staff, particularly in light of the regulatory requirement that the customer be given at least 3 days written notice (and from 1 January 2013, use best endeavours to obtain verbal or written acknowledgement from the customer that the notice has been received). There is nothing to preclude Western Power from commencing the notification process some time in advance of the 3 day notice period in order to improve the likelihood of being able to contact the customer.

412. The Authority considers that the creation of a dedicated team of seven people to independently review and have control over all distribution access requests and introduce real time system access for switching operators is not necessary just to avoid disconnecting LSEA and other sensitive loads. Western Power should instead seek to implement a robust set of processes to ensure that planned outages and the restoration of power following unplanned outages comply with their regulatory and safety obligations.

413. Western Power is also requesting additional expenditure for real time management for improvements to the monitoring and reporting of the low voltage network. The rationale for this expenditure is not clear to the Authority. It would appear that the additional monitoring is intended as a safety net for situations where a failure in the low voltage network that is not detected by the current monitoring of the high voltage network results in the interruption of supply to a LSEA. The Authority is only aware of a single incident (in 2012) where, due to inaccurate records, a LSEA was not correctly identified as being connected to a low voltage network that was interrupted by a planned outage on the high voltage network. Given that the rationale for this investment is not clear, the Authority does not consider this investment reasonable.

414. The Authority considers that while breaches of Type 1 obligations are very serious matters, Western Power's proposed additional expenditure of $29 million during the third access arrangement period is an over-reaction to a problem that should be able to be met within its existing base year operating expenditure by improving the robustness of the procedures and controls related to managing activities associated with Type 1 obligations. In the circumstances, the Authority is not satisfied that these costs meet the requirements of section 6.40 of the Access Code. The Authority notes that if Western Power considers that this expenditure is necessary and a high priority it could reorganise its operating expenditure priorities to undertake this work.

Streetlight switch wire program

415. Western Power's Amended Access Arrangement Information has increased its forecast expenditure to accelerate the streetlight switch wire program to address the current safety risk with these assets. Western Power has determined that the amounts shown in Table 29 should be added to its operating expenditure forecast. These costs are the labour costs associated with decommissioning and removal of switch wires and control boxes under the associated capital expenditure program which is discussed in paragraph 935 to 938.

416. GBA recommended that Western Power's proposed expenditure was reasonable. As a result, and considering that the Authority approved the associated capital expenditure program, the Authority has included Western Power's proposed labour costs associated with decommissioning and removal of switch wires and control boxes in the operating cost forecast as shown in Table 29.

Table 29 Final Decision Forecast of Streetlight Switch Wire Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's revised proposed	6.5	6.4	0.0	0.0	0.0	12.9
Final Decision	**6.5**	**6.4**	**0.0**	**0.0**	**0.0**	**12.9**

Clean Energy Future Package

417. Western Power's Amended Access Arrangement Information has included additional costs in its forecast network control services expenditure as a result of the Australian Government's Clean Energy Future Package which Western Power expects will increase expenditure by $0.21 million during the third access arrangement period.

418. As noted in paragraph 390, the Authority has decided to exclude network control services from the operating expenditure forecast to determine target revenue and include network control services in the D-factor scheme. As these additional costs are for increased fuel costs for network control services, the Authority similarly has excluded these costs from the operating expenditure forecast to determine target revenue.

Summary of Final Decision on non-recurrent operating costs

419. Taking account of the matters discussed above, the Authority's Final Decision in relation to non-recurrent operating costs is set out in Table 30 below.

Table 30 Final Decision Forecast of Non-recurrent Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Smart Grid	4.3	3.5	4.2	5.5	6.7	24.3
Distribution – Field Survey Data Capture Project	2.8	3.6	3.6	3.6	3.6	17.2
Distribution – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Distribution – Distribution Quotations	4.2	4.2	4.3	4.3	4.3	21.2
Distribution – GSL Payments	1.7	1.7	1.7	1.7	1.7	8.5
Compliance with Type 1 obligations	0.0	0.0	0.0	0.0	0.0	0.0
Distribution – Streetlight Switchwire program	6.5	6.4	0.0	0.0	0.0	12.9
Distribution – Total	**19.5**	**19.4**	**13.8**	**15.1**	**16.4**	**84.1**
Transmission – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Transmission – Transmission Line Decommissioning	1.0	0.8	0.2	0.2	-	2.2
Transmission – Total	**1.0**	**0.8**	**0.2**	**0.2**	**0.0**	**2.2**
Total non-recurrent operating costs	**20.5**	**20.2**	**14.0**	**15.3**	**16.4**	**86.4**

Indirect Costs

420. Indirect costs are costs that are not directly related to the networks program but are incurred as a result of the works program. They cover project management and coordination, as well as maintaining computers and facilities for operational staff. These indirect costs are allocated to activities and expensed or capitalised in line with Western Power's cost and revenue allocation method.

421. In its initial proposal, Western Power included $245 million for indirect costs. GBA's analysis indicated that there was a step increase of 17.3 per cent between the actual indirect costs incurred in the 2010/11 base year and Western Power's forecast indirect costs in 2012/13 (the first year of the third access arrangement period). GBA advised that the step increase was excessive given that indirect costs are largely fixed and that Western Power provided no explanation for the increase. GBA recommended a 13.7 per cent reduction in indirect costs allocated to operating expenditure. GBA recommended a similar reduction for indirect costs allocated to capital expenditure.

422. In the Draft Decision, the Authority considered that GBA's recommendation was reasonable and decided to reduce the amount of indirect costs allocated to operating expenditure by 13.7 per cent. As a result, the Authority required Western Power to amend its forecast indirect costs allocated to operating expenditure to the amended amounts in Table 31.

Table 31 Draft Decision Amended Forecast of Indirect Cost Allocation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Indirect – Proposed (includes non-revenue cap services)	54.3	51.3	50.2	48.3	54.9	259.1
Indirect – Proposed (excludes non-revenue cap services	51.3	48.5	47.5	45.7	51.9	245.0
Adjustment (13.7%)	(7.0)	(6.6)	(6.5)	(6.3)	(7.1)	(33.5)
Indirect – Amended	**44.3**	**41.9**	**41.0**	**39.4**	**44.8**	**211.4**

423. In response to the Draft Decision, Western Power has not accepted the 13.7 per cent reduction to its initial indirect cost forecast. Western Power revised its indirect costs as follows:

- adopted 2011/12 as the base year for the forecast;
- reduced the rate of escalation applied to forward looking costs; and
- made further reductions to the forecast costs to incorporate anticipated efficiencies as a result of the introduction of SPOW.

424. Based on GBA's advice, the Authority's main concern was with Western Power's approach to using 2011/12 as the base year. GBA noted that this is not only inconsistent with the base year used in Western Power's scale escalation model, but is also $30 million or 20 per cent higher than the scale escalation base year cost. GBA queried the volatility in Western Power's indirect costs for the current access arrangement period and had a number of concerns with Western Power's response. GBA advised that, if the 2011/12 indirect costs are to be used as a base year for indirect cost forecasting, they would need to be reviewed for efficiency. GBA noted that the indirect costs proposed in its report prior to the Draft Decision were based on 2010/11 costs which were examined by GBA for efficiency in its initial review. As GBA's recommended indirect costs were only 4 per cent lower than the forecast in Western Power Amended Access Arrangement, even though this was based on the much higher 2011/12 base year indirect costs, and because GBA made a greater provision for variable cost escalation and did not provide for SPOW efficiencies, GBA advised that there was no reason why the Authority should adjust the amount included in the Draft Decision upward.

425. The Authority has considered Western Power's amended forecast for indirect costs and agrees with GBA assessment that the amount included in the Draft Decision as shown in Table 31 should not be adjusted, particularly as Western Power's revised amount is based on a 2011/12 base year rather than the 2010/11 base year, proposed by Western Power and assessed by GBA prior to the Draft Decision for all operating expenditure items. The Authority does not believe it would be consistent to use a different base year just for this one operating expenditure item, particularly a base year that has not been assessed for efficiency.

Corporate Operating Expenditure

426. Corporate operating expenditure has been assessed separately from distribution and transmission costs. However, in determining target revenue, corporate operating expenditure is apportioned to the relevant revenue caps for distribution and transmission. Corporate operating expenditure is comprised of business support,

insurance, rates and taxes, and the Energy Safety Levy. Western Power's proposed forecasts for corporate operating expenditure are shown in Table 32.

Table 32 Proposed Corporate Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Business Support	71.2	69.5	70.4	73.1	73.6	357.8
Insurance	25.9	26.8	27.4	28.3	29.1	137.4
Rates and Taxes	6.6	7.1	7.8	8.6	9.2	39.3
Energy Safety Levy	4.3	4.3	4.3	4.3	4.3	21.4
Total Corporate Operating Expenditure – Proposed	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**	**555.9**

Business support expenditure

427. In its initial proposal, Western Power included $357.8 million for business support costs. These costs relate to corporate services, strategy and finance, regulation and sustainability, legal and governance functions and the Office of the Chief Executive.

428. In its report prior to the Draft Decision, GBA advised that the average annual expenditure of $71.6 million for the third access arrangement period is only 2.6 per cent higher than the average annual current access arrangement expenditure of $69.7 million.[110] In the Draft Decision, the Authority decided to allow Western Power's forecast business support expenditure as proposed. The Authority noted though that this was a 2.6 per cent annual average real increase to which a real labour cost escalation will also be added. In the Draft Decision, the Authority took the view that this expenditure, which is mostly fixed in nature, should provide scope for Western Power to achieve efficiencies. The Authority has addressed this issue further in paragraphs 537 to 539.

Insurance

429. In its initial proposal, Western Power included $137.4 million for insurance costs. Western Power's proposed amount included workers compensation insurance costs, which are also included in other operating costs, so an adjustment to correct for this error is necessary.

430. GBA reviewed Western Power's insurance costs and, while not experts on insurance, recommended that Western Power's forecast, after the removal of workers compensation appears reasonable.[111] In the Draft Decision, the Authority agreed with GBA's recommendation. Consequently, the Authority in its Draft Decision required that Western Power's operating expenditure be adjusted to remove the workers' compensation insurance from the proposed insurance costs as these costs are included elsewhere and Western Power was required to amend its forecast costs in accordance with those set out in Table 33.

110 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.1, p. 132.

111 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.2, p. 133.

Table 33 Draft Decision Forecast Insurance Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Insurance – Proposed	25.9	26.8	27.4	28.3	29.1	137.4
Insurance – Amended	**22.9**	**23.6**	**24.0**	**25.0**	**25.9**	**121.4**

431. In its Amended Access Arrangement, Western Power has removed the workers compensation insurance costs which were included in error in its initial proposal.

Rates and taxes

432. In its initial proposal, Western Power included $39.3 million for the payment of rates and taxes. Western Power forecast an increase in land-related taxes of 8 to 10 per cent and an increase in fringe benefits taxes by the increase in the works program as a proxy for an increased head count.

433. GBA advised that an 8 to 10 per cent nominal increase per year in land related taxes appeared to be unsustainable over time but noted this was the advice Western Power had received from the Valuer General.[112] GBA was not in a position, and nor is the Authority, to propose an adjustment which is inconsistent with the Valuer General's advice.

434. However, Western Power's escalation of fringe benefits tax was based on its works program and assumed an increase in head count of around 30 per cent by the end of the third access arrangement period, which GBA considered unlikely. GBA does not believe that the value of the approved works program is a valid proxy for headcount, as much of the program is materials and much of the labour content is outsourced. A significant proportion of Western Power's internal labour is corporate support which has a relatively fixed headcount. Given this, GBA considered that Western Power's 2010/11 base fringe benefit tax should be compounded annually by 2 per cent per annum.[113] In the Draft Decision, the Authority accepted the recommendation from GBA and considered a 2 per cent per annum increase to be reasonable. Western Power was therefore required to adopt the amended values in Table 34.

Table 34 Draft Decision Forecast Rates and Taxes Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	6.7	7.1	7.8	8.6	9.2	39.3
Draft Decision	**6.7**	**7.0**	**7.4**	**7.9**	**8.4**	**37.3**

435. In response to the Draft Decision, Western Power did not accept the forecast for rates and taxes. Western Power did not agree with the method used in the Draft Decision to adjust for the fringe benefits tax. Western Power amended its forecast for rates and taxes to take into account the 2011/12 forecast for fringe benefits tax, as well as to make a downward adjustment to correct an error.

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112 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.3, p. 134.

113 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.3, p. 134.

436. As the Authority noted in the discussion on indirect costs, the Authority does not accept Western Power's use of 2011/12 as a base year for determining its forecast costs as this is inconsistent with the scale escalation model and the Authority has not assessed the efficiency of the 2011/12 operating costs. The Authority notes that the 2011/12 costs provided were estimates and not audited costs as the number was provided prior to the conclusion of the financial year.

437. As a result, the Authority has not altered its view from the Draft Decision.

Energy Safety Levy

438. In its initial forecast, Western Power has included $21.4 million for its required payment of the Energy Safety Levy. As this payment is required and was consistent with amounts paid in the current access arrangement period, the Authority in the Draft Decision accepted Western Power's forecast amount.

439. In its response to the Draft Decision, Western Power notes it has amended its forecast to remove labour cost escalation. The Authority agrees that these costs should not include labour escalation and, on that basis, has accepted Western Power's amended forecast as set out in Table 35 below.

Table 35 Final Decision Forecast Energy Safety Levy Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	4.3	4.3	4.3	4.3	4.3	21.5
Amendment to exclude labour cost escalation	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(1.0)
Final Decision	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**20.6**

Summary of Corporate Expenditure

440. In summary, in the Draft Decision the Authority required Western Power to amend its proposed corporate operating expenditure to $538.0 million in the Draft Decision, as shown in Table 36.

Table 36 Draft Decision Corporate Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Corporate Operating Expenditure – Proposed	107.9	107.6	109.8	114.3	116.2	555.9
Adjustment to Insurance	(3.0)	(3.2)	(3.4)	(3.3)	(3.2)	(16.1)
Adjustment to Rates and Taxes	0.0	(0.1)	(0.4)	(0.7)	(0.8)	(2.0)
Corporate Operating Expenditure – Amended	**105.0**	**104.3**	**106.0**	**110.3**	**112.2**	**538.0**

Note: Some numbers do not add due to rounding.

441. Western Power's Amended Access Arrangement Information included a number of new items. These are:

- people and culture plan;

- public awareness campaign;
- Future Energy Alliance marketing campaign;
- cost sharing methodology with System Management (Markets); and
- Economic Regulation Authority Electricity Access Levy.

442. Each of these is considered below.

People and Culture Plan

443. In its Amended Access Arrangement Information, Western Power discusses a new two-year People and Culture Plan which will cost $2.1 million in operating expenditure. Western Power has advised that this new plan is required to embed a culture change program in response to recommendation 3 of the Parliamentary Standing Committee's report into Western Power's wood pole management program.

444. GBA reviewed this expenditure and, prior to becoming aware that the Western Australian Government had accepted the People and Culture Plan, sought further information from Western Power about whether this program was needed considering that disaggregation occurred in 2006 and after disaggregation Western Power had established an Enterprise Solutions Partner with the mandate to drive change through the business. While Western Power confirmed that this Partner division within Western Power is still in place, it is not responsible for culture change. GBA noted Western Power's response implies that it is possible to separate the implementation of corporate culture change from the implementation of significant changes to corporate procedures and processes. GBA considers that it is not possible to separate them in this way.

445. GBA also considered that, in a competitive environment, the costs of corporate change must be borne by shareholders. GBA considered that the ability to pass these costs through to customers only exists in monopoly situations and that, by attempting to do so, Western Power is exhibiting the very monopolistic behaviour that the program itself should be trying to overcome. As a result, GBA considered that the costs for the People and Culture Plan should be met by the shareholder.

446. The Authority agrees with GBA that the costs for this Plan should not be passed through to customers as in a competitive environment the shareholder would have to meet these costs. The Authority is also concerned that Western Power has separated its corporate cultural change from the implementation of significant changes to corporate procedures and processes.

Public Awareness Campaign

447. In its Amended Access Arrangement Information, Western Power has proposed a $3.4 million two-year public awareness campaign to increase the community's understanding of the potential dangers of Western Power's network.

448. GBA advised that maintaining public awareness of the dangers of electricity transmission and distribution assets should be an ongoing operating expenditure which is provided for in Western Power's base costs. Having said that, GBA considered that, taking into account the condition of Western Power's assets and the recent public safety issues, there may merit in a one-off intensive campaign.

449. The Authority has accepted GBA's advice that while, normally, base operating expenditure should be expected to include public awareness expenditure, a one-off

intensive campaign warning the public of the dangers of the Western Power network is not unreasonable given the recent public safety issues. As a result, the Authority has accepted the expenditure for a public awareness campaign as shown in Table 37.

Table 37 Final Decision Public Awareness Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Final Decision	**1.5**	**1.9**	**0.0**	**0.0**	**0.0**	**3.4**

Future Energy Alliance Marketing Campaign

450. Western Power's Amended Access Arrangement Information incorporated $6 million in its corporate operating expenditure forecast to cover possible campaigns and initiatives relating to the Future Energy Alliance. The Future Energy Alliance, a partnership with Synergy, was established under the direction of the Minister for Energy in December 2010. The key initiative of the Alliance is a marketing campaign designed to change consumer behaviour to become more energy efficient and reduce growth in peak demand. The continuity of the Alliance is considered in June each year and as Western Power had not been advised that the Alliance would cease when it submitted its Amended Access Arrangement Information in May 2012, it proposed to incorporate expenditure for its work in the Alliance.

451. Subsequent to its Amended Access Arrangement, Western Power advised that it believed that its obligations under the Alliance could be met from its base corporate communications expenditure and it had therefore decided not to proceed with the additional request for Future Energy Alliance funding during the third access arrangement.

452. As a result, the Authority has not assessed this expenditure, nor included it in corporate operating expenditure.

Cost Sharing with System Management (Markets)

453. In the Draft Decision, it appeared to the Authority, that Western Power included some expenditure for network operations which should be apportioned to System Management. In section 3.2.2 of Appendix A of Western Power's proposed revised access arrangement information, Western Power noted that its planning and market operations involved 'ensuring that market participants are compliant with the WEM [wholesale electricity market] Rules and that the (ring-fenced) System Management operates in accordance with the Market Rules.' This is a requirement of System Management and should be funded by it, rather than Western Power's customers. As a result, the Authority required Western Power to remove all planning and market operations expenditure from this category of investment as it appeared to relate to System Management responsibilities.

454. Based on the information provided by Western Power, the Authority also considered that control centre administration and management expenditure related to System Management responsibilities. For the purposes of the Draft Decision, the Authority decided that only 50 per cent of the proposed expenditure should be allowed in Western Power's forecast operating expenditure as set out in Table 38 below.

Table 38 Draft Decision Forecast Planning and Market Operations and Control Centre Administration and Management Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission Planning and Market Operations – proposed	1.4	1.5	1.6	1.7	1.9	8.2
Transmission Control Centre Administration and Management – proposed	0.8	0.9	0.9	1.0	1.1	4.7
Transmission Planning and Market Operations - Amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Transmission Control Centre Administration and Management – amended	**0.4**	**0.5**	**0.5**	**0.5**	**0.6**	**2.5**
Total Adjustment to Operating Expenditure	**(1.8)**	**(1.9)**	**(2.0)**	**(2.2)**	**(2.4)**	**(10.3)**

Source: Western Power's Access Arrangement Information, Appendix A, Table 12 and Authority's calculations

455. In response to the Draft Decision, Western Power provided additional information which establishes that these network operation costs do relate to Western Power's network operations and have been allocated appropriately. However, in response to the Draft Decision Western Power has reviewed the allocation of costs to System Management (Markets) and revised the corporate costs associated with providing services to System Management (Markets) – a ring-fenced area from the network business. Using a cost sharing methodology, Western Power has estimated that $4.6 million should be borne by System Management (Markets).

456. The Authority has reviewed Western Power's methodology and considers that the amount Western Power proposed to deduct from its corporate operating expenditure is reasonable. The Authority has therefore made an expenditure adjustment to reflect this in Table 39 below.

Table 39 Final Decision Cost Sharing with System Management Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Final Decision – adjustment to Corporate Expenditure	**(0.9)**	**(0.9)**	**(0.9)**	**(0.9)**	**(1.0)**	**(4.6)**

Economic Regulation Authority Electricity Access Levy

457. On 18 July 2012, Western Power wrote to the Authority requesting additional operating costs to reflect proposed statutory regulations which would require Western Power to pay for the Economic Regulation Authority's costs in relation to its electricity access functions. Western Power noted that it had been advised by the Western Australian Department of Treasury of the proposed regulations. As a result, Western Power is seeking to include $1.3 million (real as at 30 June 2012) in transmission network operating expenditure for each year of the third access arrangement period.

Western Power considers, that as all users of the Western Power Network pay for the use of the transmission system, this ensures that these costs are recovered from all users benefiting from the electricity access functions of the Economic Regulation Authority.

458. The Authority sought public comment on Western Power's proposal and received a submission from Verve Energy which considered it appropriate for Western Power to include the proposed $1.3 million (real as at 30 June 2012) in transmission operating expenditure for each year of the third access arrangement period.

459. However, as at the release of this Final Decision, the regulations are not in place and, as a result, the Authority is not able to accept the inclusion of this expenditure in Western Power's operating expenditure. Until the regulations are gazetted by the Western Australian Government, no allowance for the Authority's costs can be included in Western Power's operating expenditure (and, hence, tariffs). When the regulations are made and have commenced, Western Power will be able to apply for a mid-period revision to the access arrangement to enable it to recover any such costs.

Summary of Final Decision on Corporate Operating Expenditure

460. Taking account of the matters discussed above, the Authority has amended its forecast for the Final Decision as set out in the table below.

Table 40 Final Decision Corporate Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	**105.0**	**104.3**	**106.0**	**110.3**	**112.2**	**538.0**
Adjustment for Public Awareness Campaign	1.5	1.9	-	-	-	3.4
Amendment to Energy Safety Levy	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(1.0)
Costs to be allocated to System Management (Markets)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)	(4.6)
Final Decision	**105.4**	**105.2**	**104.9**	**109.2**	**111.1**	**535.8**

Note: Some numbers do not add due to rounding.

Input Cost Escalation

461. The Authority has assessed Western Power's operating and capital expenditure exclusive of real input cost escalation, to assist with comparing the forecast changes in these expenditures over time.

462. Western Power has incorporated into both its proposed operating expenditure and capital expenditure forecasts, movements in the cost of labour and materials that will escalate at a rate above the CPI.

463. Western Power engaged the Competition Economists Group (CEG) and Macromonitor to provide forecasts of these escalation factors for the third access arrangement.

Labour escalation

464. Macromonitor provided forecasts for labour costs in the electricity, gas, water and waste services (**EGWW**) sector in Western Australia using three different measures – the average weekly ordinary time earnings (**AWOTE**), the wage price index (**WPI**) and unit labour costs (which accounts for productivity improvements).[114]

465. CEG provided a report on both labour and materials cost escalators and has used the forecasts provided by Macromonitor when determining its recommended labour cost escalation forecasts.[115]

466. CEG considered it reasonable to use actual measures of changes in staff costs where available, in preference to much broader measures for the entire EGWW sector. Therefore, salary increases outlined in the Western Power and (Communications Electrical Plumbing Union (**CEPU**) Collective Agreement 2008 were used up to the final operation date of 1 October 2013. Forecasts provided by Macromonitor were used following 1 October 2013.

467. Of the three labour cost measures provided by Macromonitor, CEG decided to use the AWOTE measure when preparing the cost escalation calculations for Western Power. CEG noted that it used the AWOTE because it included the effects of compositional changes, including changes in the mix of skill categories and the mix of occupational categories with different pay scales.

468. CEG noted that it did not recommend the WPI because it excludes the effects of any compositional changes, including changes in the mix of skill categories or changes in the mix of occupation categories with different pay scales. The WPI assumes that the composition of the workforce will not change.

469. As has been used in recent AER final determinations in NSW and Tasmania a quarterly index was constructed by CEG to estimate forecasts when moving from forecasts based on Western Power + CEPU Union Collective Agreement 2008 which ends on 1 October 2013 and year ending June forecasts from Macromonitor.

470. In CEG's report, a single labour cost escalation factor was provided to Western Power rather than two escalation factors (an external and internal labour escalator) as proposed by Western Power in the current access arrangement. The single escalation factor combines both the internal labour costs with the external labour costs as CEG believed that both costs are driven largely by the same underlying factors.

471. Accordingly, Western Power has proposed the labour cost escalation factors, to be applied to both operating expenditure and capital expenditure, as listed in Table 41.

472. The WAMEU submission stated that the Authority needs to define the basis on which it considers the setting of the expected inflation is the most appropriate, as Western Power's forecast is 0.2 per cent higher than what Powerlink has sought in Queensland, it is higher than the mid-point of the underlying inflation target of the RBA

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[114] July 2011, Macromonitor, Access Arrangement Information – Appendix W2- *Macromonitor Report on Forecast Labour Costs.*

[115] September 2011, Competition Economists Group, Access Arrangement Information – Appendix W1- *CEG Report on Western Power Escalation Factors.*

and the ABS has recently revised its calculation for headline inflation, which has resulted in a lower inflation rate.[116]

473. The WAMEU submission was very critical of the labour escalation above CPI proposed by Western Power.

474. The WAMEU submission recommended that the Authority should obtain an independent assessment of labour price movements such as the AER does, to ensure there is less opportunity for error and inbuilt conservatism being applied. The WAMEU submission observed that CEG has a preference for using AWOTE as the basis for labour cost price movements while the AER uses labour price indices in preference to those based on AWOTE.

475. The WAMEU submission was critical of Western Power's use of the EGWW labour index and considers the index will not reflect the labour cost of non-field staff such as office staff. WAMEU questioned the past and forecast productivity figures developed by Macromonitor for Western Power as the figures suggest productivity has fallen despite the supposed benefits of dis-aggregation and corporatisation of Western Power.

476. Western Power's proposal of an AWOTE measure for labour escalation was in contrast to Western Power's proposed use of a WPI during the current access arrangement, which was supported by the Authority in its Final Decision.

477. Western Power's labour escalation factors based on the use of AWOTE also differed from recent decisions of the AER, including the final decision for Victoria Distribution Network Service Providers (**DNSPs**) and draft decision for Queensland's Transmission Network Service Provider (**TNSP**).

478. The AER has preferred the use of a WPI as opposed to an AWOTE measure that was proposed by the DNSPs and TNSP in their respective proposals.

479. In the recent Victorian final decision the AER determined that:

"To the extent that the incentives within the regulatory framework assume current labour costs are efficient, the AER considers that satisfying both the NEL and NER requires compensating a DNSP purely for expected changes in the price of labour. That is, changes in the costs to a DNSP of employing labour, unaffected by compositional changes in the quality or quantity of work performed."[117]

480. In its Draft Decision, the Authority was also of the view that if current labour costs are deemed to be efficient then Western Power should only be compensated for forecast changes in the price of that labour and should not be distorted with the addition of compositional changes.

481. Accordingly, the Authority considered that the cost escalation factors that should be applied to labour should be based on both the Western Power + CEPU Union Collective Agreement 2008 until its expiry on 1 October 2013 and then

[116] November 2011, Western Australia Major Energy Users, *Electricity Distribution and Transmission Service in the Western Power South Western Interconnected System: Response to Application.*

[117] October 2010, AER, *Victorian electricity distribution network service provider's determination 2011–2015.*

Macromonitor's WPI forecasts for the remainder of the third access arrangement period.

482. In calculating revised labour escalation factors, the Authority used the same formula as set out in the CEG report. The formula used by CEG in the report was based on a similar formula used in previous decisions by the AER.

483. As noted in paragraph 481, as the Authority accepted labour increases proposed by Western Power based on its collective agreement until its expiry on 1 October 2013, the 2011/12 and 2012/13 labour escalators remained unchanged.

484. As a result of the collective agreement not expiring until 1 October 2013 (rather than on a financial year basis) the first quarter of the 2013/14 year used the collective agreement wage increases and then for the remaining three quarters the Macromonitor's forecast WPI was substituted into the calculations in place of the AWOTE to obtain a final cost escalation figure for that year.

485. In order to calculate the labour cost escalation amounts after the collective agreement expired for 2013/14, the Authority converted the annual collective agreement wage increases (running from 1 October to 30 September annually) into financial year percentages to ensure consistent comparison with Macromonitor's forecasts.

486. For the remaining 2014/15, 2015/16 and 2016/17 years, all four quarters of the financial year are based on Macromonitor's forecast WPI. Also, as was used by CEG in its calculations for Western Power, the Authority also used a CPI of 2.5 per cent as a long term forecast for these years.

487. The Authority's revised labour cost escalation factors applied in the Draft Decision, using the Authority's approach are listed in Table 41.

Table 41 Draft Decision real labour input escalation factors (per cent above CPI)[118]

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Western Power Proposal	1.9	1.5	3.1	3.7	3.1	3.1
Draft Decision	**1.9**	**1.5**	**2.2**	**2.4**	**2.0**	**2.0**

488. Western Power has not accepted the Authority's required amendment for real labour cost escalation rates as set out in the Draft Decision.

489. Western Power in its revised proposed access arrangement revisions has not accepted the Authority's use of the Wage Price Index (WPI) and has again proposed that labour cost escalation be calculated using the Average Weekly Ordinary Time Earnings (AWOTE) method.

490. Western Power does not agree with the reasoning provided by the Authority in the Draft Decision and believes that the Authority is incorrect in applying the WPI method for three key reasons:

- While the Australian Economic Regulator (AER) has used the Labour Price Index (LPI), equivalent similar measure to the WPI, in recent decisions, this method does not take into account compositional change.

118 September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 141.

- Although Western Power has previously used the WPI method in the current access arrangement, Western Power states that the forecast and its actual results differed significantly. Western Power provided a graph in its revised proposed access arrangement revisions showing the estimated internal and external forecasts of labour escalation for the current access arrangement, which were prepared using the WPI method, were below the actual labour escalation that was experienced for that period.[119]
- While the Authority noted in the Draft Decision that if labour costs are currently deemed to be efficient then they should not be adjusted for future compositional change, Western Power believes that compositional change of the workforce is inevitable in the workplace. Western Power provided two graphs in its amended access arrangement information showing the percentage change in the share of the total workforce and the operational workforce in Western Power between 30 June 2010 and 31 March 2012.

491. In its Amended Access Arrangement Information, Western Power submitted updated forecasts for the labour cost escalation based on its preferred methodology for the third access arrangement period. These updated forecasts are shown below in Table 42.

Table 42 Western Power's revised proposed real labour input escalation factors (per cent above CPI)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Labour Escalation – revised proposed	**2.2**	**1.6**	**2.9**	**3.6**	**3.1**	**3.1**

492. Horizon Power in its submission on the Authority's Draft Decision welcomes the adoption of actual collective labour agreements to reflect short term labour costs. However, Horizon Power is concerned that the WPI may not fully represent the forward costs of labour in Western Australia. Horizon Power would prefer the Authority apply a labour escalator that is more representative of the future labour costs that are relevant to Western Australia that uses a combination of historical and labour costs and future collective arrangements.

493. The WAMEU in its submission to the Authority does not agree with the methodology used by the Authority in calculating the labour escalation costs. WAMEU notes that the cost adjustment is applied across all operating costs and does not recognise that large elements of the Western Power labour force are not in the CEPU, nor do they get paid at rates used by field staff that comprises the Electricity, Gas and Water (**EGW**) classification. The WAMEU also provided the Authority in its submission with a report prepared by Deloitte Access Economics for the AER on why the LPI is a more appropriate tool for forecasting future labour movements for regulatory purposes over the AWOTE.[120]

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119 May 2012, Western Power, *Amended Access Arrangement Information*, p. 41.

120 2 March 2012, Deloitte Access Economics, Response to issues raised in the Powerlink regulatory proposal, www.aer.gov.au/sites/www.aer.gov.au/files/DAE%20Response%20to%20issues%20raised%20in%20the%20Powerlink%20regulatory%20proposal%20%282%20March%202012%29.pdf

494. Overall, the WAMEU is of the view that the LPI approach should be used to calculate labour cost escalation. However, WAMEU also believes that like the AER, the Authority should include productivity improvements in the allowances.

495. The Deloitte Access Economics (**DAE**) report, commissioned by the AER and referred to by the WAMEU addresses a number of the criticisms of the LPI and concludes that the LPI, although not a perfect measure is the best measure for labour cost escalation and better than AWOTE.

496. With regards to compositional change (reflected in the AWOTE but not the LPI measure) in an organisation, the DAE report states that the compositional change in skill mix is a business choice. If the business chooses to pay for a skill mix with a higher (or lower) average wage, then it also gets the associated productivity benefit (loss) of that decision.

497. If the Authority was to allow the use of the AWOTE method then Western Power would benefit from using a cost escalator that takes into account compositional changes and compensates for that and also the productivity benefits that would go with this increase in skills mix, essentially benefiting twice.

498. With regards to the compositional change and the skill mix the DAE report stated that:

> "*Individuals are indeed promoted, and more junior (less skilled) individuals are hired to fill their place. A number of promotions will be made to fill vacancies at more senior levels created through turnover. Where the promotion is not for a vacancy, but is rather an addition to the number of more senior (highly skilled) staff, it is logical that this would be the result of growth in the firm more generally, and would therefore be accompanied by an increase in less skilled staff as well."*

499. The DAE report also states that:

> *"The decision to shift to a higher skilled workforce will reflect the increased productivity of that workforce. Indeed, there is no incentive for a firm to shift to a higher skilled workforce without an increase in productivity, and any move to do so would ultimately be detrimental to the ongoing operation of the firm"*

500. The DAE report uses data from the Australian Bureau of Statistics to show that the LPI has a lower standard deviation in quarterly wage growth over the last 10 years to December 2011 than the AWOTE. This is actually even more pronounced in the utilities sector as compared to all industries.[121]

501. As pointed out by the WAMEU, it is difficult to accurately forecast labour cost escalation. This challenging exercise for an organisation or regulator must be overcome by using the most accurate and robust method that is available to assist with the forecasting process.

502. The Authority is of the opinion that there is no perfect forecasting method for labour cost escalation but of the available options the WPI method provides the most reasonable forecasts for the forecasting period. The Authority notes that DAE, in its report for the AER acknowledged that the LPI method, similar to the WPI, for forecasting labour cost escalation has its limitations but is still the best overall method available. Also, the Authority considers that the WPI is a better measure of the

121 2 March 2012, Deloitte Access Economics, Response to issues raised in the Powerlink regulatory proposal, p. 3.

change in price of labour. The Authority notes that the AWOTE incorporates compositional change and does not provide an accurate measure of the change in price of labour. The Authority is determining how the change in the price of labour affects Western Power's expenditure.

503. Accordingly, after reviewing Western Power's revised proposed access arrangement revisions and expert reports, all public submissions and the available historical information on labour cost escalation for regulated industries, the Authority considers that the WPI is the most appropriate escalation method following the completion of the Western Power + CEPU Collective Agreement 2008. The Authority also notes that the real escalation rates based on the WPI are higher than the real escalation rates under the current Collective Agreement used for the third access arrangement period.

504. On this basis, the Authority has decided that the forecasts provided by the Authority in the Draft Decision which utilise the agreed upon costs of the Western Power + CEPU Collective Agreement 2008 and the forecasts provided by Macromonitor to Western Power should be adopted as the labour escalation factors for the third access arrangement period. These escalation factors are set out again in Table 43.

Table 43 Final Decision real labour input escalation factors (per cent above CPI)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Labour Escalation	**1.9**	**1.5**	**2.2**	**2.4**	**2.0**	**2.0**

Materials Escalation

505. Western Power proposed real materials escalation based on CEG forecasts for the price of Steel, Copper, Aluminium and Oil. These forecasts are set out in Table 44.

506. In the first round of public consultation, the WAMEU was very critical of the materials escalation above CPI proposed by Western Power. The WAMEU submission contends that Western Power has only included those materials most likely to increase in value faster than CPI and has neglected to include materials which are expected to increase at a lesser rate.

507. The WAMEU submission was critical of the report by CEG for Western Power, which in its view, just provides conclusions for the materials identified by Western Power and provides little in the way of quantification and reasoning on how outcomes were achieved. The WAMEU submission noted that while crude oil was expected by Western Power to increase above inflation, crude oil futures are suggesting a decrease in price. The WAMEU submission also highlighted a lack of forecast movements in exchange rates provided in the CEG report. Overall, the WAMEU submission doubts that the approach used by Western Power is reasonable.

508. The WAMEU submission expressed an expectation that the Authority ensure that the overall allowance for materials escalation reflects the movements in all materials used by Western Power. The WAMEU submission also expressed concern that the materials escalation proposed by Western Power is too conservative and should be adjusted to remove conservatism. The WAMEU submission proposed that Western Power should be required to provide a statement as to the compounded error that is implicit in the final value used.

509. The Authority noted that Western Power has not adopted an escalation factor inclusive of price changes for zinc, although, the cost of zinc was generally forecast to

increase over the period forecast by CEG. CEG provided a forecast for zinc at the request of Western Power in the terms of reference for the CEG report.

510. The Authority noted that Western Power did not include materials that were forecast to increase by less than CPI in determining an escalation factor for materials.

511. Also, the Authority noted that the forecast additional cost due to the materials escalation factors, in real dollar terms, is quite a small amount in the context of the total expenditure for the third access arrangement period.

512. In its Draft Decision, the Authority was of the opinion that for the materials escalation costs calculated by Western Power, the negligible amount calculated as a cost escalation would most likely be offset by materials that will increase in cost at below the CPI, which did not form part of the forecast.

513. Accordingly, the Authority considered that the cost escalation factor that should be applied to materials is only the CPI and that Western Power should adjust all materials forecasts that have been escalated by recalculating these with a factor of 0 per cent above the CPI.

Table 44 Authority's Draft Decision amended real materials escalation factors (per cent above CPI)[122]

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel – proposed	-1.3	-2.6	0.7	4.1	3.4	2.7
Copper – proposed	-5.3	-0.8	-0.8	-1.7	-2.4	-3.1
Aluminium – proposed	-0.9	2.8	4.1	3.9	3.3	2.6
Oil – proposed	-0.2	2.1	1.6	1.0	0.7	0.4
Steel – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Copper – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Aluminium – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Oil – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

514. In response to the Draft Decision, Western Power has not accepted the Authority's required amendment for material cost escalation rates as set out in the Draft Decision.

515. Western Power provided in its revised proposed access arrangement revisions submitted on 29 May 2012, amended forecasts for materials escalation costs, prepared by CEG at the request of Western Power.

516. These amended forecasts identify only minor changes to the original forecast figures previously submitted in Western Power's initial submission on 30 September 2011. A comparison of the amended and original proposed real materials escalation factors is shown in Table 45.

[122] September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 142.

Table 45 Comparison of Western Power initial proposed and revised proposed real materials escalation factors (per cent above CPI)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel – original proposed	-1.3	-2.6	0.7	4.1	3.4	2.7
Copper – original proposed	-5.3	-0.8	-0.8	-1.7	-2.4	-3.1
Aluminium – original proposed	-0.9	2.8	4.1	3.9	3.3	2.6
Oil – original proposed	-0.2	2.1	1.6	1.0	0.7	0.4
Steel – revised proposed	**-6.8**	**-4.0**	**3.5**	**1.8**	**0.3**	**-0.1**
Copper – revised proposed	**-10.4**	**1.3**	**0.4**	**-1.5**	**-3.4**	**-3.9**
Aluminium – revised proposed	**-13.0**	**2.6**	**5.3**	**3.9**	**2.9**	**2.5**
Oil – revised proposed	**2.6**	**7.6**	**-2.2**	**-3.4**	**-2.4**	**-1.5**

517. Western Power forecast that the expenditure impact of these revised materials escalation factors would be $0.6 million (real at 30 June 2012) for operating expenditure and $10.8 million (real at 30 June 2012) for capital expenditure.

518. During the second round of public consultation, Horizon Power noted that it understands the materials escalation methodology employed by the Authority, with materials moving at a lower rate than the CPI cancelling out materials moving with a rate above the CPI. However, Horizon Power is concerned that materials, such as copper, aluminium and steel, that feature significantly in commonly used supplies/products, and which drive the cost of these supplies, are properly accounted for in estimates of future efficient operating costs.

519. The WAMEU supports the Authority's approach to materials cost escalation, agreeing that the complexities and inaccuracies inherent in any attempt to forecast future movements and the mix of materials is a fraught exercise.

520. Western Power noted in its initial proposal that it had not applied real input cost escalation to inputs that are not expected to increase by more than CPI. Western Power identified vehicle and fleet costs, SCADA and communications infrastructure and IT materials as unlikely to increase by more than CPI.

521. No mention of the inputs identified in paragraph 520 was made in Western Power's revised proposed access arrangement revisions on the extent of increases or decreases below the CPI that these inputs were forecast to experience and their associated dollar value impact.

522. The Authority is of the opinion after reviewing all submissions and reports that there is still insufficient evidence to allow for the cost escalation of four particular materials when it has been identified that other materials inputs will not increase by the CPI and the impact of these have not been considered.

523. Whilst some materials may increase in cost above the CPI it would be inefficient to only compensate for only those materials without taking into account the whole suite of relevant materials including those that will not increase by as much as the CPI or which may in fact decrease in cost.

524. Accordingly, the Authority considers that with the information before it and in this particular case, there should be no allowance for real cost escalation in relation to materials.

Operating Cost Escalation

525. The Authority calculated a notional amount of real cost escalation for labour for Western Power based on its recommended escalation factors and for the Draft Decision added this to the total distribution and transmission operating expenditure forecasts.

526. The Authority calculated the notional amount of real cost escalation for labour by using a ratio of the index values proposed by Western Power compared with the amended indices calculated by the Authority, and applied this to Western Power's proposed dollar value of escalation for each year of the third access arrangement period.

527. The total impact of the labour escalation factors was originally forecast by Western Power to be $177.5 million for operating expenditure[123] (calculated in real dollar terms at 30 June 2012). The Authority amended this amount in the Draft Decision to $129.7 million over the third access arrangement period.

528. The total impact of the materials escalation factors was forecast by Western Power to be $0.9 million for operating expenditure[124] (calculated in real dollar terms at 30 June 2012). The Authority did not allow for any materials escalation in the Draft Decision.

529. In the Draft Decision, the Authority accordingly required the following amendment.

Draft Decision Amendment 5

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 34 and Table 35 [of the Draft Decision].

Table 46 Draft Decision Amended Real Input Escalation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Labour Escalation – Western Power proposal	8.1	19.7	35.0	48.8	65.9	177.5
Labour Escalation – Draft Decision	**8.1**	**16.0**	**25.8**	**34.5**	**45.3**	**129.7**
Materials Escalation – Western Power proposal	-0.1	0.0	0.2	0.3	0.4	0.9
Materials Escalation – Draft Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

530. As noted above, Western Power did not accept the labour and materials escalation rates and did not amend its operating expenditure forecast as required by Draft Decision Amendment 5.

123 September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 140.

124 September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 140.

531. For the Final Decision, the Authority has calculated an amount of real cost escalation for labour for Western Power based on its recommended escalation factors and has added this to the total distribution and transmission operating expenditure forecasts.

532. Rather than continuing with the calculation methodology in the Draft Decision of determining an amount for real cost escalation for labour by using a ratio of the revised index values proposed by Western Power compared with the amended index calculated by the Authority, the Authority sought further information from Western Power on the share of labour out of its revised operating expenditure forecast. The Authority has used the share derived from Western Power numbers and applied this to the Final Decision allowed labour escalation rate and total operating expenditure (prior to inclusion of input cost escalation) for each year of the third access arrangement period. The Authority considers that this methodology is more appropriate as it accounts for the approved level of operating expenditure forecast rather than basing it on a level of operating expenditure that was not approved.

533. The total impact of the labour escalation factors was forecast by Western Power to be $162.6 million for operating expenditure[125] (calculated in real dollar terms at 30 June 2012). The Authority amended this amount in the Final Decision to $99.3 million over the third access arrangement period.

534. The total impact of the materials escalation factors was forecast by Western Power to be $0.6 million for operating expenditure[126] (calculated in real dollar terms at 30 June 2012). The Authority has not allowed for any materials escalation in the Final Decision.

Table 47 Final Decision Real Input Escalation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Labour Escalation – Western Power revised proposal	6.6	18.0	32.4	45.4	60.3	162.6
Labour Escalation – Final Decision	**5.2**	**12.7**	**20.5**	**26.9**	**34.1**	**99.3**
Materials Escalation – Western Power revised proposal	-0.1	0.1	0.2	0.2	0.2	0.6
Materials Escalation – Final Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Required Amendment 5

The revised proposed access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 43 and Table 44

[125] September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 140.

[126] September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 140.

Scope for Efficiencies

535. Western Power's operating expenditure forecasts in its proposed revised access arrangement made no provision for progressively increasing the efficiency of Western Power's operating expenditure. In its Draft Decision, the Authority noted that Western Power's submission to the Authority's Issues Paper stated that Western Power had incorporated the efficiencies it initiated in the current access arrangement period and which it expects to continue in the third access arrangement period, into its forecasts. Western Power believes the incentive properties in its proposed revised access arrangement would also provide the right incentives to seek further efficiencies during the third access arrangement period. However, during the first consultation period, Griffin Power, Alinta, ERM Power and WALGA suggested that some level of future efficiency should be incorporated into Western Power's forecast operating expenditure.

536. The benchmarking exercise undertaken by GBA indicated that there is scope for Western Power to achieve efficiency gains to improve its performance to the levels of its peers in Australia (see Table 12 for GBA's results). The GBA review of Western Power's governance procedures confirmed that there is significant scope for efficiencies, especially in the areas of risk management, identification and evaluation of alternative options to meet a network development need and in improving asset databases.

537. In addition, GBA noted that the significant proposed capital investment by Western Power in modern and enhanced IT under the Strategic Program of Works (**SPOW**) program was approved by the Western Power Board on the basis of the operating efficiencies it will generate. However none of the identified efficiencies expected in the third access arrangement period had been captured in Western Power's operating expenditure forecast.

538. Western Power's proposed IT projects to address issues with maintaining an up-to-date assets register should allow Western Power to leverage efficiency gains. In particular, GBA considers that the IT projects will help to provide the asset data needed to support the introduction of a structured condition based risk management (**CBRM**) system similar to that used by industry leaders. Currently, Western Power uses an informal CBRM system. However, GBA noted that businesses that have introduced a structured CBRM approach to maintenance planning have found significant cost savings. This implies that Western Power will have significant scope to achieve efficiency gains at relatively low cost.

539. In its Draft Decision, the Authority noted that as Western Power is updating all of its main IT systems over a period of about seven years, this should increase efficiencies right across the business. Western Power is proposing to automate processes under its new IT systems which are currently done manually.

540. Overall, GBA considers that an annual efficiency target of 2 per cent should be readily achievable by Western Power.[127]

541. As noted in paragraph 428, the Authority believes that there should be scope for Western Power to achieve efficiencies in its business support costs, which Western Power has proposed will increase by, on average, 2.6 per cent annually.

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[127] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.11.

542. Given the reasons stated above regarding the scope for Western Power to readily achieve an annual efficiency target during the third access arrangement period of 2 per cent, not to mention the scope for reducing business support costs and given that Western Power's governance is on an improving trajectory, which may result in the identification of further efficiencies, the Authority considered in its draft decision that a 2 to 3 per cent annual efficiency target should be achievable.

543. In the Draft Decision, the Authority also noted that the Western Australian Government's 2011/12 Budget required all government trading enterprises, including Western Power, to implement an efficiency dividend of 5 per cent each year from 2011/12 to 2014/15.[128] The Authority further stated that it could be argued that it should make a similar efficiency assumption when determining forecast efficient operating costs. However, the Authority considered that a 2 to 3 per cent annual efficiency target for each year of the third access arrangement period, combined with the adjustments detailed in this section, would result in an appropriate balance between setting the efficient costs while providing Western Power a strong incentive to strive for further efficiencies. Any additional efficiencies achieved during the third access arrangement period would result in a lower operating expenditure base for the fourth access arrangement period which would benefit customers. For the purposes of the Draft Decision, the Authority decided that a 2 per cent compound annual efficiency target, applied from 2012/13 was reasonable.

544. In response to the Authority's Draft Decision, Western Power has not reduced its forecast operating expenditure by the Authority's 2 per cent efficiency target. Western Power considers the adjustment to be unreasonable as it believes that operating expenditure would be reduced below the level incurred by a service provider efficiently minimising costs and therefore inconsistent with the Access Code. Western Power also acknowledges that there will be efficiencies gained through the implementation of SPOW and has amended its operating expenditure by $7 million.[129]

545. Western Power argues that the Authority has:

- disregarded the advice of GBA in that the efficiency dividend should not be applied to the first year of the regulatory period;
- double-counted expected efficiencies through the adoption of historical growth rates and economies of scale;
- not taken into account the limitations of the analysis underpinning GBA's advice or attempt to adjust for the limitations;
- accepted the use of benchmarking as a singular and reliable methodology to forecast efficient costs despite practitioners elsewhere rejecting this approach;
- applied a cumulative efficiency factor of 2 per cent per annum to total operating costs which is the highest imposed in Australia since 2001; and
- not presented any analysis to determine that the efficiency expected is achievable.

546. During the second round of consultation, a number of interested parties commented on the 2 per cent compound annual efficiency target applied by the Authority in the

128 May 2011, Western Australian Government, *2011/12 Budget: Economic and Fiscal Outlook*, Budget Paper No.3, pp. 287-288.

129 May 2012, Western Power, Amended Access Arrangement Information for the Western Power Network, p. 79.

Draft Decision, mostly related to the size of the efficiency target. Energy Networks Association and Horizon Power did not support the efficiency target applied by the Authority in the Draft Decision.

547. Energy Networks Association suggest that the Authority's application of a 2 per cent efficiency target appears to be based on a broad conclusion by the Authority's technical consultant and that it is unclear on what empirical basis this conclusion was derived. Energy Networks Association considered that the Authority had weighed this conclusion against a 'broad target for desired operating efficiencies from a wide range of government trading enterprises set by the WA state government'.[130]

548. Horizon Power considers that Government Trading Enterprises are already subject to an annual efficiency dividend of 5 per cent on discretionary operating expenditure and the application of compounded efficiency targets over and above that set by Government presents an onerous burden on service providers. Horizon considers problems occur when regulators recommend additional efficiency targets without providing clear linkages as to where or how these efficiencies are to be realised and without due explanation for the size of the target. Horizon considers that regulators should work with the service provider to determine what efficiency is achievable and how the reduced cost profile would impact levels of activity and service delivery.

549. Alinta, Energy Made Clean, WACOSS and WAMEU support the Authority's application of an efficiency target, with the latter three respondents suggesting that the Authority increase the efficiency target to at least 3 per cent.

550. Alinta believes the Authority should determine the operating expenditure efficiency target independent of any Government decision to impose a larger efficiency target.

551. Energy Made Clean considered that the 2 per cent efficiency target is not a challenging target and that a target of 3 to 4 per cent would more likely deliver the necessary improvements in Western Power.

552. WACOSS considered that a 3 per cent efficiency target is appropriate as it will drive Western Power over the course of the third access arrangement period to near the average of the current benchmark performance for the interstate comparator group. WACOSS noted that given Western Power's performance during the current access arrangement period, that simply providing Western Power with time to improve without simultaneously placing incentives on it to improve may not lead to improvements. WACOSS considered that comparing Western Power to State averages for transmission and distribution companies would tend to advantage a more urban-based distributor such as Western Power. WACOSS considered that it would be better to compare Western Power with other urban based distribution networks in Australia.

553. While WAMEU considers that the Authority should apply a 3 per cent annual efficiency factor to operating expenditure, it noted that the Western Australian Government is requiring a 5 per cent annual efficiency target and an efficiency factor of 4 per cent per year would be necessary to reach a 20 per cent improvement it considers would be necessary for Western Power to be on the efficient boundary based on the current access arrangement expenditure.

[130] May 2012, Energy Networks Association, Submission to Authority, p. 2.

554. The Western Australian Department of Finance also noted in its submission that it was 'supportive of the approach taken by the Authority, to drive Western Power to achieve efficiencies in the operation of its network and deliver lower costs to consumers'.[131]

555. In reviewing Western Power's operating expenditure forecast, GBA further assessed whether efficiency gains should be available to Western Power during the third access arrangement period. In particular it investigated the efficiencies expected from the SPOW program, which Western Power acknowledges will result in efficiencies, and undertook further benchmarking analysis.

556. Western Power provided a copy of a Statement of Program Intent dated 30 June 2009 which provided a high level justification for the SPOW program and contained a very high level summary of the expected benefits of SPOW. GBA asked Western Power to quantify the SPOW benefits it had included in its expenditure forecast for the third access arrangement period. Western Power responded that there was a total of $135.6 million identified efficiencies through to the end of the third access arrangement period, with $59.6 million of efficiency benefits already realised in the current access arrangement period. GBA is sceptical about the $59.6 million of efficiencies claimed to have been realised as Western Power is suggesting that, on an annual basis, more efficiencies were captured before the information systems were actually implemented than forecast to be captured following implementation which is unlikely.

557. GBA noted that Western Power considers that the bulk of the SPOW efficiencies will be captured through capital expenditure rather than operating expenditure. However, GBA considers that the operating expenditure efficiencies will be substantially greater than suggested by Western Power. GBA analysed the expected benefits of the SPOW in Western Power' s Statement of Program Intent and suggests that taking the mid-point of the relevant line items related to operating expenditure forms an appropriate basis for setting a target for the annual operating efficiency gains to be achieved by 2016/17. GBA calculate that the annual operating expenditure efficiency gain will be $36.9 million in 2016/17.

558. While acknowledging the limitations of comparative benchmarking, GBA considers that it is nevertheless used in the industry, including Western Power, as a tool for producing a high level sanity check. GBA assessed the application of an efficiency target on Western Power using multiple scenarios against Queensland and South Australian peers (as GBA considers that these more closely resemble Western Power's service area). GBA's analysis indicates that the application of an annual compounding efficiency factor of 2 per cent commencing from 2013/14 in order to achieve an annual operating expenditure efficiency gain of $36.9 million in 2016/17 will bring Western Power's performance more in line with Queensland service providers on a composite operating expenditure per customer km indicator, although Western Power would still not match the performance by South Australian service providers. When assessed on more common industry standard measures of operating expenditure per km of line and operating expenditure per customer, Western Power is projected to be performing only better than Queensland service providers for the operating expenditure per customer.

[131] May 2012, Government of Western Australia – Department of Finance, *Draft Decision on Western Power's Proposed Revisions to its Access Arrangement for the third regulatory period*, p. 1.

559. The Authority has considered Western Power's arguments and those of interested parties. On balance, the Authority prefers GBA's analysis which suggests that achievement of annual operating efficiency benefits of $37 million by 2016/17 is reasonable considering that Western Power's SPOW program has already identified these benefits and Western Power has itself acknowledged that there is a level of benefits from this program. Also, GBA's high level benchmarking suggests that benefits of this magnitude are realistic. While Western Power amended its operating expenditure for its Amended Access Arrangement Information to take account of $7 million worth of operating expenditure benefits, the Authority has not included these efficiencies in the line item forecasts and has instead incorporated its decision on the level of benefits of the SPOW program in the overall efficiency factor (to avoid double counting).

560. The Authority considers that while there are most likely other areas where Western Power may be able to achieve efficiencies, the gain sharing mechanism provides further incentive for Western Power to drive even more efficiency.

561. The achievement of annual efficiency benefits of $37 million by 2016/17 would require a compounding efficiency factor of 2 per cent to be applied from 2013/14. The Authority has applied this calculation to its amended total operating expenditure prior to including real input cost escalation for the previous year. The efficiency adjustment for the Final Decision is shown in Table 48 below.

Table 48 Final Decision Efficiency Adjustment (real $ million at 30 June 2012) [132] [133]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	8.6	17.2	25.9	34.2	43.6	129.5
Final Decision		8.9	18.2	27.4	37.0	91.5

Treatment of ex-post review risk

562. In response to the Draft Decision, Western Power's amended access arrangement information proposes the inclusion of one per cent of the capital expenditure forecast for the third access arrangement period to be added to operating expenditure for the risk that the Authority writes down capital expenditure in undertaking an ex-post NFIT when determining the efficient investment to be added to Western Power's capital base.

563. The Authority is required to assess Western Power's forward-looking and efficient costs. The Authority does not consider it reasonable to allow any amount in operating expenditure because of a possibility that the Authority might not allow all of Western Power's capital expenditure during the third access arrangement period to be rolled into the opening capital base for the fourth access arrangement period. The Authority is required to undertake an ex-post efficiency assessment of Western Power's capital expenditure before including this expenditure in the capital base. Western Power's ex-post review risk operating expenditure proposal assumes that its capital expenditure during the third access arrangement will not be completely efficient. In

[132] Amended transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

[133] Amended transmission and distribution expenditure is allocated a portion of amended indirect operating expenditure based on the ratio of Western Power's proposed allocation of these costs.

effect, Western Power wants an allowance for inefficiency in its operating expenditure forecast. The Authority does not consider this acceptable and nor does it comply with the Access Code requirements of only including the forward-looking and efficient costs of providing covered services.

Total Operating Expenditure

564. Taking into account the consideration of the individual cost line items as set above, scale escalation, real cost escalation and other adjustments, the Authority in the Draft Decision considered that Western Power's forecasts of operating expenditure as set out in the proposed revised access arrangement information are not consistent with the requirements of section 6.40.

565. Table 49 below sets out the Authority's Draft Decision in relation to operating expenditure forecasts.

Table 49 Draft Decision Operating Expenditure (real $ million at 30 June 2012)[134]

Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base[135]	249.4	249.4	249.4	249.4	249.4	1,246.9
Step changes[136]	0.5	0.5	0.5	0.5	0.5	2.6
One-off adjustments	9.7	9.7	9.7	1.0	1.0	31.1
Growth escalation[137]	9.6	14.5	19.6	24.7	30.0	98.4
Total recurrent network costs	**269.2**	**274.1**	**279.2**	**275.6**	**280.9**	**1,379.0**
Non-recurrent network costs	**14.0**	**13.8**	**14.0**	**15.3**	**16.4**	**73.5**
Expensed indirect network costs	44.3	41.9	41.0	39.4	44.8	211.4
Corporate costs	**105.0**	**104.4**	**106.0**	**110.3**	**112.2**	**538.0**
Gross operating expenditure	**432.5**	**434.2**	**440.3**	**440.6**	**454.3**	**2,201.9**
Efficiency adjustment	**(8.6)**	**(17.2)**	**(25.9)**	**(34.2)**	**(43.6)**	**(129.6)**
AA3 operating expenditure	**423.8**	**417.0**	**414.5**	**406.5**	**410.7**	**2,072.4**
Input cost escalation	8.1	16.0	25.8	34.5	45.3	129.7
Adjustment for System Management expenditure	(1.8)	(1.9)	(2.0)	(2.2)	(2.4)	(10.3)
Total	**430.1**	**431.1**	**438.3**	**438.7**	**453.5**	**2,191.8**

134 Revised Access Arrangement Information, p. 131.

135 Recurrent network base is calculated by adjusting the Authority's adjusted base year network operating expenditure with the modelling adjustments noted in the 'Step Change Adjustments' section.

136 The Authority has reallocated some step change adjustments requested by Western Power to the base operating expenditure and also one-off adjustments.

137 This includes both network and customer growth.

566. In the Draft Decision, the Authority accordingly required the following amendment.

Draft Decision Amendment 6

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure as indicated in Table 39 [of the Draft Decision].

567. In response to the Draft Decision, Western Power did not accept this amendment. Western Power's revised forecast, which is discussed in the paragraphs above, is summarised in Table 50 below.

Table 50 Western Power's Revised Proposed Operating Expenditure (real $ million at 30 June 2012)

Expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base	247.8	247.8	247.8	247.8	247.8	247.8	247.8	1,239.0
Step changes	-0.2	-0.3	6.7	6.8	6.7	6.7	6.7	33.5
One-off adjustments	1.7	6.9	11.4	11.4	11.4	2.7	2.7	39.5
Network growth		6.0	11.8	16.3	25.4	33.4	48.1	135.0
Customer growth		0.8	1.4	2.2	2.9	3.7	4.5	14.6
Total recurrent network costs	**249.3**	**261.2**	**279.1**	**284.4**	**294.2**	**294.2**	**309.7**	**1,461.7**
Carbon Tax & SPoW efficiencies adjustments			-0.1	-0.4	-0.4	-0.4	-0.3	-1.6
Non-recurrent network costs	**40.6**	**56.6**	**49.0**	**46.1**	**45.4**	**49.2**	**55.0**	**244.8**
Expensed indirect network costs	45.4	51.0	50.4	46.7	45.2	42.4	42.9	227.7
Corporate costs	**101.3**	**102.8**	**108.7**	**109.7**	**108.0**	**110.8**	**111.9**	**549.1**
Input cost escalation			6.4	17.8	32.3	45.5	61.8	163.9
Total AA3 operating expenditure[138]	**436.5**	**471.6**	**493.6**	**504.5**	**524.6**	**541.8**	**581.0**	**2,645.5**

568. As discussed in the preceding paragraphs, the Authority has given consideration to the information included in Western Power's amended access arrangement information. The Authority's Final Decision in relation to operating expenditure is set out in Table 51 below.

138 Western Power has included expenses for non-revenue cap services of $94.9 million in non-recurrent network costs and this is also included in total operating expenditure for the third access arrangement period. Western Power then deducts this non-revenue cap expenditure from target revenue.

Table 51 Final Decision Operating Expenditure (real $ million at 30 June 2012)[139]

Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base[140]	250.2	250.2	250.2	250.2	250.2	1,250.9
Step changes[141]	7.7	9.1	9.1	9.1	9.1	44.0
One-off adjustments	8.7	8.7	8.7	0.0	0.0	26.1
Growth escalation[142]	9.6	14.7	19.9	25.2	30.6	100.1
Total recurrent network costs	**276.1**	**282.6**	**287.9**	**284.5**	**289.9**	**1,421.0**
Non-recurrent network costs	**20.5**	**20.2**	**14.0**	**15.3**	**16.4**	**86.4**
Expensed indirect network costs	44.3	41.9	41.0	39.4	44.8	211.4
Corporate costs	**105.4**	**105.2**	**104.9**	**109.2**	**111.1**	**535.8**
Gross operating expenditure	**446.3**	**449.9**	**447.8**	**448.4**	**462.2**	**2,254.6**
Efficiency adjustment	**-**	**8.9**	**18.2**	**27.4**	**37.0**	**91.5**
Total before cost escalation	**446.3**	**441.0**	**429.7**	**421.0**	**425.2**	**2,163.2**
Input cost escalation	5.2	12.7	20.5	26.9	34.1	99.3
Total after cost escalation	**451.5**	**453.7**	**450.1**	**447.8**	**459.3**	**2,262.4**

569. Taking into account the individual cost line-items as set out above, the Authority considers that Western Power's forecasts of operating expenditure as set out in the revised access arrangement information are not consistent with the requirements of section 6.40. The target revenue and price control in the proposed revisions to the access arrangement must be amended to be consistent with the operating cost forecasts set out in Table 52 below.

139 Revised Access Arrangement Information, p. 131.

140 Recurrent network base is calculated by adjusting the Authority's adjusted base year network operating expenditure with the modelling adjustments noted in the 'Step Change Adjustments' section.

141 The Authority has reallocated some step change adjustments requested by Western Power to the base operating expenditure and also one-off adjustments.

142 This includes both network and customer growth.

Table 52 Final Decision forecast operating expenditure (real $ million at 30 June 2012)[143] [144] [145]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission						
Draft Decision	100.1	99.2	100.9	103.6	107.5	511.3
Final Decision	**103.7**	**102.8**	**103.1**	**105.2**	**107.8**	**522.6**
Distribution						
Draft Decision	330.0	331.9	337.4	335.1	346.0	1,680.5
Final Decision	**347.8**	**350.9**	**347.0**	**342.6**	**351.6**	**1,739.9**

Required Amendment 6

The revised proposed access arrangement must be amended to reflect a forecast of operating expenditure as indicated by the Final Decision values in Table 52.

143 Draft Decision transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

144 Draft Decision transmission and distribution expenditure is allocated a portion of amended real input escalation based on Western Power's proposed allocation of transmission and distribution network operating expenditure.

145 Draft Decision operating expenditure does not include operating expenditure for non-revenue cap services.

Opening Regulatory Capital Base for the Third Access Arrangement Period

Access Code Requirements

570. The capital base is the value ascribed to the network assets that are used to provide covered services. Where the target revenue for the price control is set by reference to the service provider's approved total costs, section 6.43 of the Access Code provides for the value of capital related costs to be calculated by determining a capital base and calculating a return on the capital base and an amount of depreciation.

571. Under the first access arrangement, an initial capital base was established under section 6.46 of the Access Code at an "optimised deprival value" (**ODV**) of the network assets.

572. Section 6.48 of the Access Code requires that the capital base at the start of any access arrangement period, other than the first access arrangement period be determined in a manner that is consistent with the Code objective. A note to section 6.48 indicates that:

> {A number of options are available in relation to the determination of the capital base at the start of an access arrangement period, including:
>
> - rolling forward the capital base from the previous access arrangement period applying benchmark indexation such as the consumer price index or an asset specific index, plus new facilities investment incurred during the previous access arrangement period, less depreciation and redundant capital etc; and
> - valuation or revaluation of the capital base using an appropriate methodology such as the Depreciated Optimised Replacement Cost or Optimised Deprival Value methodology.}

573. Notwithstanding that section 6.48 of the Access Code does not mandate a specific method for determining the capital base, sections 6.51A to 6.63 of the Access Code contemplate new facilities investment being added to the capital base and the value of any redundant assets being subtracted from the capital base, consistent with use of the "roll forward" method for determination of the capital base.

574. Section 6.51A of the Access Code provides that new facilities investment may be added to the capital base if it passes certain tests:

> 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.

575. The new facilities investment test is set out in section 6.52 of the Access Code:

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.

576. Under the “modified test” referred to in section 6.52(b)(i)B of the Access Code, and set out in section 6.53, the Authority may approve new facilities investment below the threshold value where the Authority determines that approving the access arrangement with the modified test would be efficient and would promote the Code objective.

577. Section 6.54 of the Access Code requires that the Authority, in determining whether new facilities investment satisfies the new facilities investment test, must have regard to whether the new facilities investment was required by a written law or a statutory instrument.

578. Sections 6.61 to 6.63 of the Access Code provide for an amount to be subtracted from the capital base in respect of redundant network assets.

579. With proposed revisions to an access arrangement typically being considered by the Authority prior to commencement of the access arrangement period in which the revisions to the access arrangement will apply, the capital base at the start of the access arrangement period will need to be determined (if being determined by the roll-forward method) without knowledge of all the new facilities investment that will occur in the remainder of the current access arrangement period. In this circumstance, section 6.50 of the Access Code permits the capital base to include an amount in respect of new facilities investment that is forecast to occur before the access

arrangement start date if, at the time of inclusion, it is reasonably expected to satisfy the test in section 6.51A when made.

Proposed Revisions

580. Consistent with the current access arrangement, Western Power specified capital base values separately for the transmission and distribution networks.

581. The capital base values for each of the transmission and distribution networks were calculated by Western Power for the beginning of the third access arrangement period using a roll-forward method that involves commencing with the opening value at the beginning of the second access arrangement period and:

- adding the actual (and estimated actual for 2011/12) values of capital expenditure (new facilities investment) during the second access arrangement period that Western Power considers to meet the requirements of the new facilities investment test under section 6.52 of the Access Code (excluding gifted assets and capital expenditure that is funded by customers via capital contributions);[146]
- deducting values of redundant assets;
- deducting values of depreciation as allowed for in target revenue for the second access arrangement; and
- making an adjustment for inflation expressed in dollar values at 30 June 2012.

582. In the proposed revisions to the access arrangement submitted on 30 September 2011, Western Power made the following new additional adjustments in order to calculate the opening capital base value at the beginning of the third access arrangement:

- expenditure relating to inventory in the actual (and estimated actual for 2011/12) values of capital expenditure;
- a mid-year timing assumption for capital expenditure; and
- investment incurred during the first access arrangement period, which the Authority determined to be inefficient, to the opening capital base for the third access arrangement period.

583. Western Power's calculated values of the capital base for the transmission and distribution networks (incorporating forecast values for 2011/12) at the commencement of the third access arrangement period (1 July 2012), as submitted on 30 September 2011, are set out in Table 53 and Table 54 below.

[146] Capital expenditure is added to the regulated capital base on an "as incurred" basis rather than an "as commissioned" basis.

Table 53 Western Power's Proposed Transmission network capital base at 30 June 2012 (real $ million at 30 June 2012)[147]

	2009/10	2010/11	2011/12	Total
As submitted 30 September 2011				
Opening asset value	**2,321.4**	**2,443.8**	**2,535.0**	**2,321.4**
Capital expenditure	202.9	171.1	146.5	520.5
Inventory				0.0
Asset disposals	-6.1	-0.3	0.0	-6.4
Depreciation	-74.4	-79.6	-90.0	-244.0
Accelerated depreciation	0.0	0.0	0.0	0.0
Mid-year timing assumption				0.0
Investment from prior periods			53.5	53.5
Closing asset base	**2,443.8**	**2,535.0**	**2,645.1**	**2,645.1**

Numbers do not add up due to rounding.

147 Access arrangement information, Section 10.2.3, Tables 57 and 58 and amended access arrangement information, Section 7.7.1, Tables 28 and 29.

Table 54 Western Power's Proposed Distribution network capital base at 30 June 2012 (real $ million at 30 June 2012)[148]

	2009/10	2010/11	2011/12	Total
As submitted 30 September 2011				
Opening asset value	**3,005.2**	**3,288.4**	**3,561.4**	**3,005.2**
Capital expenditure	441.1	443.2	485.1	1,369.4
Inventory				0.0
Asset disposals	-0.9	0.0	0.0	-0.9
Depreciation	-152.8	-166.1	-183.7	-502.6
Accelerated depreciation	-4.2	-4.1	-4.0	-12.3
Mid-year timing assumption				0.0
Investment from prior periods			95.4	95.4
Closing asset base	**3,288.4**	**3,561.4**	**3,954.2**	**3,954.2**

Considerations of the Authority

584. The Authority has considered whether Western Power's calculation of the capital base for each of the transmission and distribution networks is consistent with the requirements of the Access Code. These considerations are documented below under the following headings:

- the general method applied in calculating the capital base;
- verification that stated new facilities investment in the second access arrangement period occurred (or for 2011/12 is reasonably forecast to occur); and
- determination of the capital base at the commencement of the third access arrangement period, taking into account:
  - an assessment of actual capital expenditure in the second access arrangement period against the test in section 6.51A of the Access Code;
  - depreciation;
  - redundant assets;
  - Western Power's proposed mid-year timing assumption; and
  - investment from prior periods.

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148 Access arrangement information, Section 10.2.4, Tables 61 and 62 and amended access arrangement information, Section 7.7.2, Tables 31 and 32.

General Method

585. Western Power has calculated the capital base for each of the transmission and distribution networks using a roll-forward method, applied in a manner consistent with the method contemplated in the note to section 6.48 of the Access Code.

586. The roll-forward method has been favoured by utility regulators throughout Australia and is the method mandated for electricity transmission and distribution networks of the NEM under Chapters 6A and 6 of the NER.

587. The Authority is satisfied that the method used by Western Power is consistent with the Code objective.

Verification of Capital Expenditure in the Second Access Arrangement Period

588. In accordance with the Authority's Guidelines for Access Arrangement Information, Western Power has provided regulatory accounts that reconcile the costs of regulated activities with a set of base accounts for the business. These regulatory accounts provide a reconciliation of claimed new facilities investment with actual capital costs incurred in 2009/10 and 2010/11 as indicated in Table 55.

Table 55 Reconciliation of claimed new facilities investment for 2009/10 and 2010/11 with recorded capital costs for the Western Power business ($ million at 30 June 2012)

Network and Year	Base Account	Adjustments	Regulatory Account	Claimed new facilities investment
Transmission 2009/10:				
Capital expenditure	250.4	11.1	261.5	261.5
Contributions	(13.3)	(22.6)	(35.9)	(35.9)
Net expenditure	237.1	(11.5)	225.6	225.6
Transmission 2010/11				
Capital expenditure	188.4	(16.9)	171.5	169.4
Contributions	(47.0)	25.3	(21.7)	(21.7)
Net expenditure	141.4	8.4	149.8	147.6
Distribution 2009/10				
Capital expenditure	520.6	(1.1)	519.5	519.5
Contributions	(94.6)	13.9	(80.7)	(80.7)
Net expenditure	426.0	12.8	438.8	438.8
Distribution 2010/11				
Capital expenditure	531.6	1.4	533.0	533.0
Contributions	(92.2)	1.1	(91.1)	(91.1)
Net expenditure	439.4	2.5	441.9	441.8

589. In the Draft Decision, the Authority noted that Western Power had excluded $2.1 million transmission expenditure in 2010/11 from its new facilities investment claim as it related to expenditure on the connection for the Binningup Desalination Plant, which the Authority assessed as not meeting the new facilities investment test in its decision published on 2 March 2011.[149]

149 2 March 2011, Economic Regulation Authority, *New Facilities Investment Test Binningup Desalination Final Decision* .

590. The adjustments made in the regulatory accounts to capital expenditures for transmission include:

- removal of capitalised borrowing costs that are not properly recorded as capital expenditure in the regulatory accounts;
- restating capital contributions to be on a 'cash received' basis;
- reversal of a write down in the statutory accounts for cancelled/deferred projects; and
- inventory adjustments.

591. The Authority observes that the regulatory accounts presented by Western Power were audited for Western Power by the Office of the Auditor General. The Authority has had the regulatory accounts reviewed by BDO.

592. In the Draft Decision, the Authority considered the adjustments made in the regulatory accounts in relation to the first two adjustments noted above (to remove capitalised borrowing costs and restate capital contributions on a cash received basis) are appropriate and in line with previous practice. However, the Authority did not consider the adjustments in relation to cancelled/deferred projects and inventory should have been made.

593. The 2010/11 regulatory accounts includes an increase to capital expenditure of $14.5 million, which is described as being to reverse the 2010/11 statutory write down for cancelled/deferred capital projects as the capital expenditure qualifies for recognition in the regulatory asset base. In the Draft Decision the Authority took the view that expenditure that relates to cancelled or deferred projects does not meet the requirements of the new facilities investment test. To the extent that such expenditure has been identified for write-down in the statutory accounts, it should not be included in the capital base.

594. The 2009/10 regulatory accounts included an increase to capital expenditure of $20.896 million, which is described as being for year-end statutory inventory adjustments. The adjustment was subsequently reversed in the 2010/11 accounts as Western Power decided it did not wish to proceed with such an adjustment. Whilst the net effect for the 2009/10 and 2010/11 years in nominal terms is neutral, the Authority considered the figures should be restated correctly for each year for the purposes of establishing the opening capital base to ensure balances are stated correctly in real price terms.

595. In the Draft Decision, the Authority required capital expenditure for the 2009/10 and 2010/11 year to exclude expenditure relating to cancelled or deferred projects and for each year to be restated correctly to remove the statutory inventory adjustment made in the regulatory accounts. The following amendment was required.

Draft Decision Amendment 7

The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to cancelled or deferred projects and to reverse the statutory inventory adjustments in both years.

596. In response to the Draft Decision, Western Power has reversed the statutory inventory adjustments and provided revised expenditure amounts. However, Western Power has not excluded the expenditure relating to cancelled or deferred projects.

597. In the amended access arrangement information, Western Power notes that it prepares its annual statutory financial statements in line with the requirements of the International Financial Reporting Standards (**IFRS**), which requires expenditure that will not result in the creation of an asset (cancelled or deferred projects) to be expensed. Western Power considers that the test that applies for determining whether expenditure can be added to the capital base, and therefore whether it is reported in the regulatory financial statements, is the new facilities investment test which is not based on the requirements of the IFRS for the defined construction and creation of an asset.

598. The Authority does not agree that the expenditure on cancelled/deferred projects falls within the definition of New Facilities Investment under the Access Code as it is not properly categorised as capital costs. 'New facilities investment' is defined in section 1.3 of the Access Code as the capital costs incurred in developing, constructing and acquiring a new facility.

599. Section 4.5 of the Access Code provides for the Authority to publish guidelines setting out in further detail what information must be included in access arrangement information in order for it to comply with the requirements of sections 4.2 and 4.3 of the Access Code.[150] Section 4.3 of the Access Code relevantly requires the access arrangement information to include, if applicable, information detailing and supporting the measurement of the components of approved total costs in the access arrangement. Approved total costs, as defined, include capital-related costs determined in accordance with section 6.43 of the Access Code. Therefore, the Authority's guidelines may set out specific requirements for capital-related costs.

600. The Authority published its updated guidelines for access arrangement information in December 2010. These guidelines include the requirements for regulatory financial statements, which must be included in Western Power's access arrangement information. Section 2.3 of the guidelines sets out the broad principles for preparing regulatory financial statements:

> The accounting principles and policies applied in compiling financial information that forms part of the access arrangement information must:
>
> - have a recognisable and rational economic basis;
> - satisfy accounting concepts of relevance and reliability; and
> - accord with applicable Australian accounting standards.

601. Section 3.8.1 of the guidelines sets out specific requirements in relation to capital expenditure which are:

> "The accounting adjustments made in the preparation of regulatory financial statements must be consistent with ensuring that the capital expenditure:
>
> - reflects the total amount associated with capital assets that have been installed or passed to the control of the service provider's business within each accounting period, including the cost of assets that have been the subject of a capital contribution from any party; and

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150 Sections 4.2 and 4.3 of the Access Code set out general requirements for what must be included in a service provider's access arrangement information.

- is recorded on an "as incurred" basis and includes expenditure on capital assets that did not enter into service during the year, but excludes any amount for the interest (or like allowance) incurred during construction."

602. The Authority does not consider that the adjustment made by Western Power when preparing its regulatory financial statements (i.e. to capitalise expenditure that was not permitted to be treated as such in the statutory accounts on the basis that it was not in accordance with accounting standards) is permitted under the Authority's guidelines for the preparation of regulatory financial statements. Consequently the expenditure relating to cancelled and deferred projects is not "new facilities investment" as it does not meet the requirements for capital expenditure.

603. The Authority notes Western Power's statement that capital projects may be cancelled or deferred following investigation of alternative options, or a change in underlying assumptions and considers this was particularly evident in the second access arrangement period, "when the global downturn and economic uncertainty prompted more conservative pace of expansion". Western Power submits that the actual peak demand reached during the second access arrangement period "fell well short of that predicted by the forecast on which the AA2 submission was based" and that "a number of projects that began at the end of the AA1 period or early in 2009/10 were stopped as the load growth requirements changed".

604. As discussed in paragraph 612 below, the Authority's technical adviser noted in its report for the Draft Decision that:

> "The uncertainty around the availability of funds, together with the write-down in the value of the capital base as a result of the Authority's AA2 final decision, led Western Power to review its capital works plan and a number of projects were put on hold pending the outcome of this review. Following the review a number of projects have been deferred or cancelled."

605. Taking account of the above statement and given the weaknesses in corporate governance identified during the first access arrangement which, although significantly improved, still required further work during the second access arrangement period, the Authority is not convinced that these deferred and cancelled projects relate only to factors outside of Western Power's control. Western Power has not provided any specific evidence to demonstrate that the cancelled or deferred projects met the new facilities investment requirements at the time they were incurred. In the absence of any such evidence, the Authority considers the amounts are likely to reflect the inefficiencies identified in the last access arrangement review in relation to Western Power's planning processes, which Western Power addressed subsequent to the review and resulted in some projects being cancelled or deferred.

606. In any event, Western Power's statements on this matter do not address the Authority's fundamental concern that the inclusion of expenditure relating to cancelled or deferred projects would not fall within the definition of capital expenditure.

607. Taking account of the matters discussed above, the Authority continues to maintain the requirement that the expenditure relating to the cancelled and deferred projects (as identified in the statutory accounts) must not be included in the regulatory capital base.

608. Western Power has provided the Authority with a copy of its unaudited 2011/12 financial regulatory statements. The Authority notes Western Power has included an adjustment of $22.1 million to transfer expenditure relating to cancelled and deferred projects from operating expenditure to capital expenditure. For the same reasons as

outlined above, the Authority has excluded this adjustment from the amount of capital expenditure added to the opening capital base as shown in Table 56 below.

Required Amendment 7

The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to the cancelled or deferred projects identified in the statutory account audit.

Capital Base at the Commencement of the Third Access Arrangement Period

Capital Expenditure during the second access arrangement period

609. A comparison of forecast and actual capital expenditure for the transmission and distribution networks (net of capital contributions and gifted assets) over the first and second access arrangement periods is shown in Figure 5 and Figure 6 below.

Figure 5 Transmission network capital expenditure (real $ million at 30 June 2012)

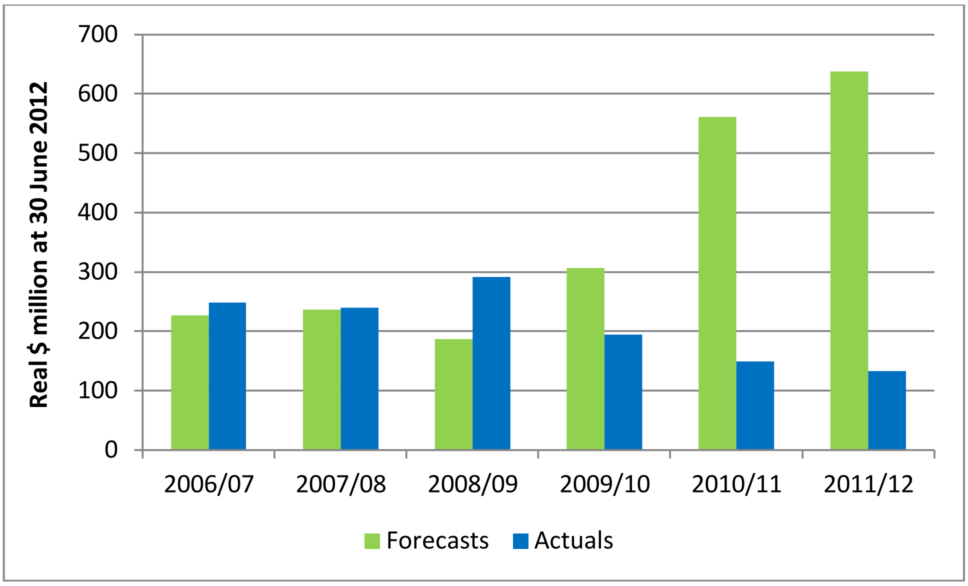
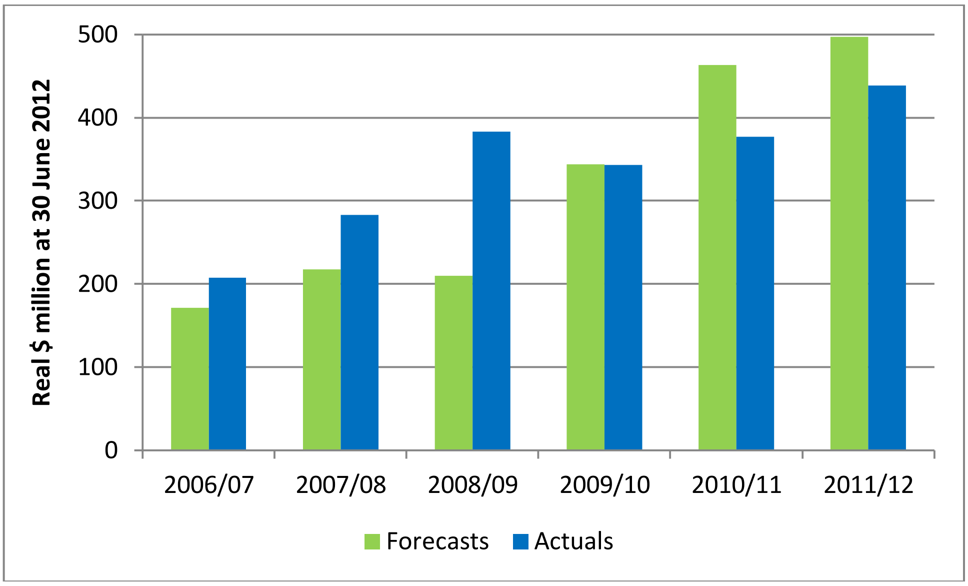


Figure 6 Distribution network capital expenditure (real $ million at 30 June 2012)



610. As can be seen in the figures above, Western Power has spent significantly less than the amount forecast for the second access arrangement period. Based on the expenditure included in Western Power's access arrangement information submitted to the Authority on 30 September 2011, transmission expenditure was $957 million (in $ real 30 June 2012) or 63 per cent below the forecast, and distribution expenditure was $180 million (in $ real 30 June 2012) or 11 per cent below the forecast.

611. At the time of the Draft Decision, the latest forecast provided by Western Power for the 2011/12 year (the final year of the current access arrangement period), indicated the underspend is likely to increase by a further $54 million. To the extent that the underspend relates to investment subject to the Investment Adjustment Mechanism, an adjustment is made to target revenue for the third access arrangement period to adjust for any under or overspend. This is discussed further in paragraphs 1234 to 1239.

612. For the purposes of the Draft Decision, the Authority's technical consultant reviewed the actual level of capital expenditure for the second access arrangement period against the amounts forecast at the second access arrangement review. GBA noted that:[151]

> The main reason cited by Western Power for the lower level of capital expenditure in the AA2 period is the impact of the global financial crisis (GFC), although it also indicated that deliverability was an issue in some areas. Western Power indicated that the GFC affected the availability of funding and its budget allocation from the Government was less than the AA2 capital expenditure approved by the Authority. Given this, Western Power had to request additional funding from the Department of Treasury. The uncertainty around the availability of funds, together with the write-down in the value of the capital base as a result of the Authority's AA2 final decision, led

[151] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 46-47.

Western Power to review its capital works plan and a number of projects were put on hold pending the outcome of this review. Following the review a number of projects have been deferred or cancelled.

Another reason given by Western Power for the reduced AA2 capital expenditure was favourable weather conditions, which presumably led to lower levels of remedial work due to a reduction in asset failures and outages.

613. To assist the Authority to understand the reasons for the underspend over the second access arrangement period, GBA compared the actual and forecast capital expenditure for the second access arrangement period by asset category. For the transmission service, GBA identified that capacity expansion, customer-driven and generation-driven projects had the biggest under expenditure with these categories accounting for slightly over 90 per cent, or nearly $900 million of the total underspend.

614. Underspend on customer driven projects amounts to 29 per cent of the total capital expenditure approved for the second access arrangement period, or 64 per cent of Western Power's total transmission related capital expenditure underspend. This was due to lower than expected demand for connection to the network and also to the impact of process and cost efficiencies achieved by Western Power. GBA acknowledged that customer driven capital expenditure is difficult to forecast as Western Power must react to customer applications. Its ability to forecast customer requirements in advance is limited.

615. GBA obtained a table from Western Power that provides further detail of the underspend relating to capacity expansion expenditure.[152] The largest underspend ($259 million) related to the Mid West Energy Project, the majority of which has been deferred until the third access arrangement period. A further $241 million has been "deferred indefinitely", $211 million has been deferred due to a "review of transmission planning approach and processes" and $156 million is described as being "deferred".

616. GBA considered the extent to which demand growth below the level anticipated at the time of the second access arrangement review may explain the level of underspend. However, its analysis of the actual maximum demand compared with the forecast maximum demand showed that actual demand for 2011 was actually higher than the forecast, which suggests that the significant reduction in transmission capacity expansion capital expenditure has been achieved in spite of an actual demand comparable to, or even higher than, the forecast at the time of the second access arrangement review.

617. In relation to the distribution service, GBA identified that the expenditure categories with the most significant underspend were capacity expansion, safety and reliability.

618. The largest underspend in distribution capacity expansion related to high voltage distribution network projects being deferred or cancelled due to improved investment decision processes. Western Power also indicated that, as a result of improvements in processes relating to distribution planning, investment decision making and documentation requirements, a number of planned capacity expansion projects have been deferred or cancelled. An amount of $29 million on the Perth CBD duct and pit systems was deferred as a result of funding constraints and subsequent reprioritisation of the works program.

[152] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* Table 5.1, p. 48.

619. The most material expenditure areas affecting the underspend for safety, environment and statutory expenditure relate to bushfire management and power quality compliance. GBA advised that Western Power provided numerous reasons for the expenditure variances, including operational efficiency improvements and reducing labour costs from bundling work across programs by geographic region.

620. For reliability driven expenditure, which was $57 million below forecast, GBA notes that Western Power stated that funding reliability projects became less critical as they were meeting and maintaining service standard benchmarks so expenditure was transferred to more critical work programs.

621. In contrast to network capital expenditure, actual expenditure for information technology and business support expenditure was $40 million higher than forecast with the largest overspend relating to information technology.

622. More than 50 per cent ($22.3 million) of this difference is due to the fact that IT infrastructure expenditure is now fully recovered from regulated revenues. Prior to 2010/11, Western Power shared its IT infrastructure with Synergy, Horizon Power and Verve Energy, which were disaggregated from Western Power in April 2006. Capital expenditure and operating expenditure relating to the disaggregated entities were recovered from these entities and those relating to Western Power were charged back to the regulated business through business unit charges. Western Power's sourcing model changed in 2010/11 and it no longer holds capital assets to provide IT infrastructure to the disaggregated entities.

623. GBA's overall conclusion in relation to the comparison of actual and forecast capital expenditure during the second access arrangement period was:[153]

> *"Western Power's total capex during AA2 is expected to be 34 per cent ($1.3 billion) lower than the $3.9 billion approved by the Authority. The major areas of under-expenditure were network related, particularly capacity expansion and customer driven capex, on transmission and, to a lesser extent, distribution assets. However, non network IT capex was overspent.*
>
> *Most of the under-expenditure was in the capacity expansion and customer driven capex categories. The funding allocated in the AA2 access arrangement to finance the under-expenditure in these categories will be returned to customers during AA3 through the IAM [Investment Adjustment Mechanism]. However, the IAM does not apply to non-growth driven capex and the funding provision for non-growth driven capex that was not utilised in AA2 will be retained by Western Power and not returned to customers.*
>
> *Customer driven capex was significantly lower than the level forecast at the time of AA2 approval, indicating a reduced demand for network connection, particularly from larger customers. This capex is difficult to forecast.*
>
> *Western Power further suggested that the GFC reduced the demand for electricity and much of the approved AA2 capex was therefore not necessary. However, our analysis indicates that the peak demand in 2010-11, the most recent year for which an actual peak demand is available, was comparable to that anticipated at the time the Authority issued its final decision on the AA2 access arrangement.*
>
> *A major reason for the under-expenditure was that the Authority's AA2 final decision did not allow all Western Power's actual AA1 capex to be included in the opening capital*

153 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 52-53.

base for AA2. As a result, Western Power put much of its planned capacity expansion expenditure on hold while it reviewed its network development planning processes. Subsequently, many planned projects have been deferred or cancelled. A further factor impacting the actual capex during AA2 has been funding constraints imposed by the Government. Western Power finances its capital works program from funding provided by the Western Australian Treasury, which we understand has required all state owned entities to restrain their capex programs as a response to the GFC. Western Power has not been immune to these pressures.

Notwithstanding this significant capex underspend, Western Power has met or exceeded 34 of the 38 (89 per cent) AA2 access arrangement network service level benchmarks over the first two years of AA2. Hence, the capex under-expenditure has not caused Western Power's service levels, on average, to fall below the service levels forecast at the time of AA2 approval. In fact the actual service levels have been significantly better than anticipated, since we understand that the AA2 service level benchmarks were set at a level where it was thought that there was only a 50 per cent probability of each benchmark being exceeded.

We [GBA] conclude that there was a significant level of inefficiency in Western Power's AA2 capex forecast, which was higher than it should have been. While Western Power's capex management, project forecasting and estimating processes have now improved, the Authority may wish to take a conservative approach in approving the AA3 capex. The Authority could decide that, given that any capacity expansion capex overspend that meets NFIT requirements can be recovered in AA4 through the investment adjustment mechanism, it is better for the approved capex to be a little lower, rather than substantially higher, than the amount eventually required. Customers will then not be asked to pay more during AA3 than needed to fund the actual capex requirement, and the incentive on Western Power to deliver only an efficient level of capex is likely to be greater. This is because the actual AA3 capex is likely to be subject to more intense ex-post scrutiny at the time of the AA4 review if it is higher than the Authority's approved amount."

Application of the New Facilities Investment Test to Actual Capital Expenditure

624. In order to include the actual (and estimated actual for 2011/12) capital expenditure incurred during the second access arrangement period in the capital base, Western Power must satisfy the Authority that the expenditure meets the new facilities investment test under section 6.52 of the Access Code.

625. As noted above, Western Power has included the entire capital expenditure incurred in 2009/10 and 2010/11, apart from $2.1 million relating to Binningup Desalination Plant, in its calculation of the opening capital base for the third access arrangement period. It has also included its total forecast capital expenditure for 2011/12 in the capital base.

626. The new facilities investment test of section 6.52 of the Access Code comprises two parts.

627. The first part of the new facilities investment test under section 6.52(a) of the Access Code is a test of whether the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, taking into account whether the new facility exhibits economies of scale or scope, the increments in which new capacity can be added and forecasts of sales of services. This is hereafter referred to as the "efficiency test".

628. The second part of the new facilities investment test under section 6.52(b) of the Access Code is a test of whether the new facilities investment provides benefits that justify addition of the new facilities investment to the capital base of the covered

network and the recovery of the cost of the investment from users of the network generally. The limbs of the second part of the new facilities investment test provide for new facilities investment to be added to the capital base if one or more of three conditions is satisfied:

- Unless a modified test has been approved under section 6.53, the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment (the "incremental revenue test"); or
- 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 (the "net benefits test"); or
- the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services (the "safety and reliability test").

629. The purpose of the second part of the new facilities investment test is to enable market forces to discipline investment in the network and to ensure that investment only occurs where there is a net economic benefit. The manner in which this is achieved is to allow new facilities investment to be added to the capital base where the benefits are such that those who generate, transport and/or consume electricity in the SWIS (as a group) are better off (or at least no worse off) in economic terms than they would be if the investment did not occur. The benefits to existing users may be in the form of:

- economies of scale in the network, which is the subject of the incremental revenue test under section 6.52(b)(i)A of the Access Code;
- broad benefits through better functioning of the covered network or electricity system as a whole, which is the subject of the net benefits test under section 6.52(b)(ii) of the Access Code; and
- the maintenance of safety and reliability of the network, which is the subject of the safety and reliability test under section 6.52(b)(iii) of the Access Code.

630. In the event that the benefit to existing users is less than the value of new facilities investment, the residual amount (that would not satisfy the new facilities investment test) would need to be financed by some other means. This would typically be by a capital contribution from the user of the network or end customer of electricity whose service application gives rise to the need for the investment. The requirement for the new user to pay a contribution should, in principle, engender efficient investment, as the new user would only pay a contribution where the benefit to the user exceeds the value of the contribution.

631. In order to advise the Authority for the Draft Decision, the Authority's technical adviser, GBA, undertook a review to assess whether actual and forecast expenditure for the second access arrangement period meets the new facilities investment test. This was done by reviewing a sample of 19 capital projects undertaken during the second access arrangement period to assess whether these projects individually met the new facility investment test requirements. The review included an assessment of:

- the extent to which Western Power applied its expenditure management governance processes in the development, approval and implementation of the project or program;
- the justification for any positive or negative variance between the estimated cost at the time of project or program approval and the final project or program cost;

- the justification for project or program implementation schedule changes; and
- the scope of the forecast project compared to the scope at the time of project approval.

632. GBA's approach was predicated on the assumption that if a capital expenditure project or program was implemented in accordance with Western Power's expenditure governance procedures then, assuming these procedures were consistent with good industry practice, it can be assumed that implementation was efficient and wasteful expenditure did not occur.

633. GBA also considered the extent to which the project satisfied the second part of the new facilities investment test. This excluded an examination of the basis on which this part was satisfied and whether this assessment was made at the time the project was approved in a manner that is consistent with Western Power's governance procedures.

634. Subsequent to submitting the proposed revisions to the access arrangement on 30 September 2011, and prior to the Draft Decision being published, Western Power updated its forecast expenditure for the 2011/12 year. GBA's review was based on this updated forecast. GBA noted that its review indicated that Western Power was still uncertain of the status of some of the 2011/12 forecast capital expenditure. The Authority anticipated that Western Power would include an updated forecast for the 2011/12 year as part of its response to the Draft Decision.

635. The results of GBA's review were detailed in Appendix A of its report and summarised in sections 5.3.2.1 to 5.3.3.

636. GBA noted that the documentation provided by Western Power for each individual project or program review varied in the level of detail and the quality and quantity of information provided, which made it difficult in some cases to assess the level of rigour applied by Western Power in developing the scope of the projects or programs and the priority given to developing and evaluating different project alternatives.

637. Apart from reservations about the extent to which different alternatives were developed and evaluated in the project development phase, GBA advised the Authority that the implementation of Western Power's expenditure governance processes during the second access arrangement period were generally good and that the management of capital expenditure had improved as a result.

638. However, in its review of specific projects, GBA identified a number of expenditure items which in its view did not meet the new facilities investment test. These comprised:[154]

- $5.7 million in relation to a cost overrun on phase 1 of the Mobile Work Solution Project, which forms part of the Strategic Program of Works (**SPOW**);
- $102,000 incurred on planning for a second Picton-Busselton 132 kV Line, which has been deferred indefinitely;
- $4.5 million in relation to planning and environmental costs, which are not directly related to a specific project or program and GBA considers do not meet the requirements of the new facilities investment test; and

154 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 59-60.

- $1.9 million in relation to transmission line relocations, which Western Power intends to recover in full from the customers concerned.

639. In addition, GBA noted that it had only reviewed 44 per cent of the total SPOW capital expenditure and, in light of its findings in relation to the Mobile Work Solution Project, was unable to form an opinion on the efficiency of the projects it had not reviewed.

640. Based on the advice provided by GBA, the Authority took the view in the Draft Decision that the expenditure identified in paragraph 638 and 639 above, which totals $21.2 million, did not meet the requirements of the new facilities investment test and therefore should not be included in the opening capital base for the third access arrangement period. The Authority estimated that $12 million of the adjustment relates to transmission and $9.2 million relates to distribution and for modelling simplicity, the Authority assumed the adjustments apply evenly over the second access arrangement period.

641. The Authority, accordingly, required that the amount of new facilities investment for the second access arrangement period that is to be added to the capital base should be reduced to exclude investment to the value of $21.2 million.

642. In response to the Draft Decision, Western Power has not accepted this amendment and considers that all of the above expenditure meets the new facilities investment test and should be included in the opening capital base for the third access arrangement period. Western Power provided additional information which it considers supports its case.

643. The Authority's technical adviser, GBA has reviewed the additional information provided by Western Power and concluded it has no reason to change its view from the Technical Report prepared for the Draft Decision.[155] GBA's latest report includes further comment on each of the items previously identified and the new information provided by Western Power, which the Authority has considered below.

$5.7 million in relation to a cost overrun on phase 1 of the Mobile Work Solution Project

644. Western Power did not accept the Authority's draft decision that this expenditure did not meet the new facilities investment test. In its response to the Draft Decision, it has provided further information that it considers supports its view that the expenditure should be included in the opening capital base. The Authority's technical adviser has reviewed this information and concluded that the project was not managed properly and, as a result, mistakes were made that should have been avoided.

645. The Authority's technical adviser notes that "the problems that have beset this project do not reflect well on Western Power's ability to effectively manage the implementation of complex IT systems. As of September 2011 the wood pole inspection component, which was originally forecast to be implemented by June 2010 for a cost of under $3 million, had (under a best case scenario) been only partly implemented for a cost of up to $8.6 million."

646. Taking account of the serious deficiencies in project management noted by the Authority's technical adviser, the Authority maintains its view that the cost overrun reflects inefficiencies and should not be included in the capital base.

155 Geoff Brown & Associates, Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision, September 2012, p.2.

$102,000 incurred on planning for a second Picton-Busselton 132 kV Line

647. The Authority notes that it has already included a requirement that the statutory accounting adjustment for cancelled and deferred projects discussed in paragraphs 593 to 607 must be reversed in the regulatory accounts so that these costs are not included in Western Power's capital base. Consequently, a specific adjustment to remove the costs relating to the second Picton-Busselton 132 kV Line are not required.

$4.5 million in relation to planning and environmental costs that are not directly related to a specific project or program

648. In response to the Draft Decision, Western Power states that it considers these to be valid costs and that they were not forecast as operating costs for the second access arrangement period. Western Power notes that these costs include early strategic planning costs that were incurred prior to Gate 1 in Western Power's works program model. Following Gate 1, the business begins attributing costs directly to individual projects that are established to address a defined network need. Western Power notes that its latest forecast for these costs for 2011/12 is $6.5 million and that it has included them in its revised opening capital base for the third access arrangement period.

649. The Authority does not accept Western Power's assertion that planning and environmental costs were not included in forecast operating costs for the second access arrangement period. The approved costs were based on what an efficient service provider would require which would include normal non-capital planning and environmental costs.

650. Western Power has provided the Authority with a copy of its unaudited 2011/12 financial regulatory statements. The Authority notes Western Power has included an adjustment of $6.2 million to transfer early strategic planning costs from operating expenditure to capital expenditure. For the purposes of the Final Decision, the Authority has excluded this adjustment from the amount of capital expenditure added to the opening capital base as shown in Table 56 below.

651. As discussed in paragraphs 599 to 602 above, the regulatory financial statements must comply with the Authority's access arrangement information guidelines. This includes the requirement that the regulatory financial statements must comply with accounting standards. These costs have been treated as operating costs in the statutory accounts as they do not meet the requirements for capitalisation. Consequently they must be treated on a consistent basis in the regulatory financial statements.

652. Therefore, the Authority maintains its view that these costs do not meet the new facilities investment test and must be excluded from the regulatory capital base. The Authority has given further consideration to the forecast of such costs in its consideration of forecast operating expenditure.

$1.9 million in relation to transmission line relocations

653. Western Power did not comment on the Authority's decision to exclude this expenditure from the capital base as it will be recovered in full from the customers concerned. The Authority maintains the Draft Decision requirement that these costs should not be included in the capital base.

$9 million in relation to a cost overrun on elements of the Strategic Program of Works

654. In response to the Draft Decision, Western Power has provided information in relation to three major SPOW projects that had not previously been reviewed by the Authority's technical adviser.

655. GBA has reviewed this information and notes that:

> "In all three projects reviewed in this section, the business case costs were significantly higher than the estimate in the allowed AA2 capex forecast and in all three cases the final project cost exceeded the original business case budget. Western Power notes that in all three cases that the cost estimates in the AA2 capex forecast were based on a preliminary analysis only. While this is undoubtedly true, it does seem that the project scope as outlined in the business cases generally included features that were not allowed for in the original AA2 capex estimate. Without a more detailed examination, we cannot comment on the extent to which this scope creep was justified."

656. GBA also notes that:

> "In the development of its capex business cases, Western Power requires, amongst other things, an assessment of whether or not the project meets the NFIT requirements of the Access Code. In most cases SPOW projects have been assessed as meeting the requirements of the second leg of the NFIT through the safety and reliability test; that is being necessary to maintain the safety and reliability of the network or Western Power's ability to provide covered services. In our view this is not an appropriate test to apply to capex on business system enhancements. Such expenditure is not needed to maintain the safety or reliability of the network or to provide covered services, but is intended to improve Western Power's operating efficiency"

657. The Authority notes GBA's comments that it is not able to comment on the extent to which the increase in costs due to scope creep was justified. However, taking account of the project management weaknesses in relation to SPOW projects identified by GBA, and the fact that the business cases were not based on a cost benefit analysis demonstrating that the projects would result in a net benefit, the Authority does not consider Western Power has demonstrated that the costs meet the new facilities investment test. The Authority will allow the amounts approved in the second access arrangement in relation to these projects to be rolled into the capital base but not the cost overrun, which amounts to $9 million.

658. The Authority considers that any future similar projects should be subjected to a rigorous cost benefit analysis demonstrating a business case for the expenditure before being approved by Western Power.

659. The Authority has amended the adjustment it made in the Draft Decision to remove the amount relating to the Picton-Busselton 132 kV line. The amended total amount that the Authority considers does not meet the new facilities investment test is $21.1 million. The Authority has estimated that $11.9 million of the adjustment relates to transmission and $9.2 million relates to distribution and for modelling simplicity, the Authority has assumed the adjustments apply evenly over the second access arrangement period. The revised adjustment is included in Table 57 below.

Summary of New Facilities Investment for the second access arrangement period

660. For the purposes of the Draft Decision, the Authority recalculated the amount of new facilities investment in the second access arrangement period that it considered met the new facilities investment test as set out in Table 56 below.

Table 56 Draft Decision-Amounts of new facilities investment in the second access arrangement period to be added to the capital base (real $ million at 30 June 2012)[156]

	2009/10	2010/11	2011/12
Transmission			
Total new facilities investment claimed by Western Power	225.6	147.6	193.8
Reversal of regulatory accounting adjustments in relation to inventory and projects deferred or cancelled	(23.2)	7.9	
Revised forecast for 2011/12			(50.5)
Expenditure which does not meet new facilities investment test (paragraph 641)	(4.0)	(4.0)	(4.0)
Adjustment for the Mid West Energy Project to make consistent with the approved NFIT amount			6.9
Value to be added to the capital base	198.3	151.6	146.1
Distribution			
Total new facilities investment claimed by Western Power	438.8	441.8	544.5
Reversal of regulatory accounting adjustments in relation to inventory and projects deferred or cancelled	0.9	(1.2)	
Revised forecast for 2011/12			(3.8)
Expenditure which does not meet new facilities investment test (paragraph 641)	(3.1)	(3.1)	(3.1)
Value to be added to the capital base	436.6	437.5	537.6

661. The Draft Decision required the following amendment.

Draft Decision Amendment 8

The proposed revised access arrangement should be amended to reflect the values shown in Table 56 above.

662. As noted in the discussion above, Western Power provided further information on three major SPOW projects which the Authority has considered. Western Power has also provided its final estimate of expenditure for the 2011/12 financial year, which has been incorporated in the Authority's assessment. As a result of the Authority's considerations above, the Authority's amended assessment of new facilities investment in the second access arrangement period is set out in Table 57 below.

156 Expenditure on Strategic Program of Works projects which does not meet the new facilities investment test was allocated based on the ratio of Western Power's proposed allocation of IT expenditure to transmission and distribution in each year of the regulatory period.

Table 57 Final Decision-Amounts of new facilities investment in the second access arrangement period to be added to the capital base (real $ million at 30 June 2012)[157]

	2009/10	2010/11	2011/12
Transmission			
Total new facilities investment claimed by Western Power[158]	199.2	167.9	163.3
Deduction of costs relating to projects written off or cancelled and early planning costs which should not have been capitalised		(14.4)	(26.0)
Expenditure which does not meet new facilities investment test (paragraph 659)	(4.0)	(4.0)	(4.0)
Adjustment for the Mid West Energy Project to make consistent with the approved NFIT amount			6.5
Value to be added to the capital base	195.2	149.5	139.8
Distribution			
Total new facilities investment claimed by Western Power[159]	434.3	435.1	510.6
Deduction of costs relating to projects written off or cancelled and early planning costs which should not have been capitalised		(0.3)	(2.4)
Expenditure which does not meet new facilities investment test (paragraph 659)	(3.1)	(3.1)	(3.1)
Value to be added to the capital base	431.2	431.7	505.1

Required Amendment 8

The proposed revised access arrangement must be amended to reflect the values shown in Table 57 above.

Inventory

663. In the proposed revisions to the access arrangement, Western Power included an amount relating to inventory assets in the opening capital base for the third access arrangement period which it stated was to “recover the financing costs associated with efficiently holding these assets for users of covered services”.

664. Western Power provided information in Appendix D of its proposed revised access arrangement information explaining how it determined the level of inventory and conducted comparisons with other service providers, which it considers demonstrated that its proposed amount falls within the range of values for inventory in other states.

665. In the Draft Decision, the Authority acknowledged there may be a working capital requirement in relation to the need to hold inventory, but it considered Western Power’s proposal to add inventory to the capital base was overly complex and lacked transparency. Western Power suggested that its proposed approach was consistent

157 Expenditure on Strategic Program of Works projects which does not meet the new facilities investment test was allocated based on the ratio of Western Power’s proposed allocation of IT expenditure to transmission and distribution in each year of the regulatory period.

158 Adjusted to remove mid year inflation and updated for 2011/12 unaudited accounts.

159 Adjusted to remove mid year inflation and updated for 2011/12 unaudited accounts.

with the practices of other electricity network businesses and referred to the published Cost Allocation Methods (**CAM**) for a number of companies.[160] However, the Authority was unable to establish that these companies included inventory costs in their capital values and considered the CAM was more likely to be describing how the cost of materials taken from inventory is allocated (i.e. once it has been established that such materials form part of capital or operating expenditure).

666. In the Draft Decision, the Authority gave further consideration to the requirement for a return on working capital in relation to inventory in paragraphs 1130 to 1134 and required amendment 9 to the revised access arrangement.

Draft Decision Amendment 9

Western Power's proposed adjustment to include the cost of inventory in the capital base must be removed.

667. In response to the Draft Decision, Western Power accepted this amendment and removed inventory costs from the capital base. The Authority is satisfied that Draft Decision Amendment 9 has been complied with.

Asset Disposals

668. During the second access arrangement review, the Authority determined that the value of any revenues from disposal of assets in the first access arrangement period should be added to the value of redundant assets applied in the calculation of the capital base at the commencement of the second access arrangement period.

669. Western Power has followed this process in its calculation of the opening capital base for the third access arrangement period by deducting asset disposals based on the gross asset sales proceeds.

Depreciation

670. A note to section 6.48 of the Access Code contemplates a roll forward calculation of the capital base involving a deduction of an amount of depreciation.

671. In calculating its proposed value of the capital base at the commencement of the third access arrangement period, Western Power has applied values of depreciation taken into account in determining notional capital base values and the target revenue for the second access arrangement period, escalated for inflation to dollar values at 30 June 2012. The Authority is satisfied that this approach is consistent with applying the roll-forward calculation in a manner consistent with the Code objective.

672. Western Power has also proposed including accelerated depreciation in relation to distribution assets that were decommissioned due to the State Underground Power Program. This is consistent with the forecast assumptions for the second access arrangement period.

673. In the Draft Decision, the Authority's technical adviser, GBA, noted that Western Power had not included accelerated depreciation in relation to wooden poles or meters that are replaced. Whilst many of these assets will have reached the end of their useful life and already be fully depreciated, GBA considered there would be

160 Western Power Access Arrangement Information Appendix D, p. 1.

instances of some of these assets not being fully depreciated. The consequence of this is that the cost of those assets will continue to be recovered over the notional life of the asset, and therefore included in future charges, rather than being written off immediately and included in current charges.

674. In the Draft Decision, the Authority required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 10

Western Power must establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

675. In response to the Draft Decision, Western Power has not accepted this amendment.

676. Western Power considers that, if the opening capital value is reduced to reflect accelerated depreciation without an adjustment to increase Western Power's target revenue for the additional depreciation, this would amount to a determination of redundant capital. Western Power notes that section 6.62 of the Access Code sets out a number of criteria that must be taken into account when determining whether assets should be removed from the capital base.

677. Alternatively, if target revenue is increased to reflect the accelerated depreciation, Western Power considers this would result in higher prices to customers and additional costs to Western Power to identify and calculate the additional depreciation amount. Western Power considers there is no benefit to customers from adopting this approach and that it would be inconsistent with section 6.4 of the Access Code, which only allows for the recovery of forward looking efficient costs.

678. In the Draft Decision, the Authority did not intend that costs arising from accelerated depreciation would not be recovered by Western Power through target revenue. Given that all amounts included in the capital base have previously been approved as meeting the new facilities investment test, and that any future investment would be required to meet the new facilities investment test before it could be included in the capital base, the Authority accepts that the "return of" that investment should be recovered by Western Power.

679. The Authority notes the point made by Western Power that accelerated depreciation, if passed on to users, will lead to higher prices to customers. In the long term the impact on customers would be neutral in net present value terms, however, in the short term prices would be higher.

680. The Authority considers that any potential redundant assets would, most likely, be within the initial asset base determined at the beginning of the first access arrangement period. The Authority has reviewed the remaining asset lives of these assets, in particular those relating to meters and wood poles, and notes that metering assets will be fully depreciated by the end of the third access arrangement period and wood poles will be fully depreciated by the end of the fourth access arrangement period. The Authority considers the remaining asset value of any redundant assets would be small and, in any case, will be written off over a relatively short period of time. The Authority also recognises that it would not be possible to attribute regulatory net asset values to specific assets, so any assessment of accelerated depreciation could only be done by applying broad brush calculations. Taking all these circumstances into account, the Authority does not require Draft Decision Amendment 10 to be implemented.

Mid-Year Timing Assumption

681. In the proposed revisions to the access arrangement, Western Power adopted a mid-year timing assumption for capital expenditure to establish the opening capital base for the third access arrangement period. Western Power stated that 'mid-year timing is appropriate to simulate the impact of incurring new facilities investment throughout the year'.[161] It also noted the timing of its "summer ready" program required a significant portion of its investment program to be completed by December each year.

682. Western Power stated that, to be consistent with the target revenue end-of-year cash flow timing assumption, capital expenditure added to the capital base effectively on a mid-year basis must be adjusted to an end-of-year cash flow. It noted this had the effect of capitalising the first six months of costs and provided for them to be recovered over the life of the assets. Western Power achieved this by adjusting the new facilities investment in each year for the time value of money for six months by applying a specified factor to new facilities investment and adding this amount to the capital base. Western Power noted that its proposed revision was in line with the approach currently used by the AER in its 'Post Tax Revenue Model' (**PTRM**).

683. A number of submissions[162] from interested parties during the first round of public consultation raised significant concerns with this proposed amendment, noting that it would result in higher charges for customers and had no justification.

684. In the Draft Decision, the Authority noted that the change in timing assumption proposed by Western Power was a departure from the approach proposed by Western Power and approved by the Authority in the past two access arrangement review periods, which assumed end-of-year timing for capital and operating expenditure incurred and revenue collected. A change in timing assumption for capital expenditure incurred mid-year would result in an increase in target revenue (target revenue would be maintained at a higher level due to the return on assets and depreciation being calculated on a higher regulatory asset value).

685. Furthermore, Western Power's proposed modelling approach did not recognise the benefits to Western Power of receiving revenue throughout the year. If this was recognised, this would have the effect of decreasing target revenue because Western Power receives a time value of money benefit from receiving revenue throughout the year, rather than all of the revenue at the end of the year.

686. The end-of-year cash flow modelling is preferred by the Authority for its transparency and simplicity of use, recognising that it does not reflect the actual cash flows of Western Power's business. The more precise, but significantly more complex alternative, would be to model all cash flows throughout the year. While not proposing this, Western Power's proposal was inconsistent in its treatment of different cash flows.

687. Western Power's proposed mid-year capital expenditure timing also did not account for the fact that assets will be retired from the capital base throughout the year. As assets are said to be added to the capital base throughout the year, it is reasonable to assume that assets would also become obsolete or disposed of throughout the year. As a result, under Western Power's proposal, the return on the capital base is higher than should otherwise be as the capital base is not written down on a mid-year basis.

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161 Revised Access Arrangement Information, Section 10.2.6, p. 243.

162 Landfill Gas and Power, WALGA and WAMEU.

AER Approach

688. As noted above, Western Power's proposed revision is similar to the approach currently taken by the AER. However, it should be noted that the AER has previously raised concerns with its PTRM.

689. The PTRM was originally developed by the ACCC for transmission networks. When responsibility for regulating distribution networks moved from the state regulators to the AER, the AER was required to develop guidelines, including a revenue model. The AER used the transmission PTRM as a starting point and carried out a consultation process in 2007.

690. In its Issues Paper[163], the AER noted that the adoption of a model which assumed operating expenditure and revenue on an end-of-year basis and capital expenditure on a mid-year basis is internally inconsistent. The AER noted that improvements to the transmission PTRM could be made through present value adjustments to operating expenditure and revenue. However, the AER noted that this would only reduce 'material over-compensation of revenue requirements' which is a consequence of the transmission PTRM's current timing assumptions in certain circumstances.

Conclusion

691. Although Western Power pointed to the approach adopted by the AER to support its proposed revision, it did not mention other differences in relation to cash-flow modelling assumptions between Western Power's approach and the AER's approach. Most significantly, the AER does not include an allowance for return on working capital. Historically, Western Power has done so and is not proposing that the allowance be removed or adjusted as a result of its proposed changes to modelling capital expenditure.

692. The Authority considered Western Power was inconsistent in its proposed modelling changes as it did not propose that the Authority should account for revenue collection on a mid-year basis. The same arguments Western Power raised in relation to capital expenditure could also be made in relation to revenue recognition as it is also received throughout the year. The proposed change by Western Power also did not reflect that capital expenditure would be retired throughout the year. The Authority considered these inconsistencies would result in Western Power receiving an arbitrary benefit at the expense of customers, contrary to the Code objective.

693. Western Power's proposed mid-year capital expenditure timing added further complexity to the financial modelling and is not consistent with the modelling of other cash flows as noted above. As a result, the Authority did not approve Western Power's proposal to adjust capital expenditure timing to mid-year.

694. The Authority accordingly required the following amendment to the proposed revised access arrangements.

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163 AER, Issues Paper Guidelines, models and schemes for electricity distribution network service providers, November 2007.

Draft Decision Amendment 11

The proposed revised access arrangement must be amended such that the 'time value of money adjustment' for mid-year capital expenditure timing is removed from the rolled forward capital base and notional capital base for AA3.

695. In response to the Draft Decision, Western Power has accepted the required amendment and has removed the time value of money adjustment to the rolled forward capital base and the notional capital base for the third access arrangement period.

696. Western Power notes that the AER has accepted that the mid-year timing assumption for capital expenditure with end of year timing assumptions for revenues and operating expenditure is internally inconsistent but that it has deferred further consideration of the cash-flow timing and that the AER does not provide for working capital. Western Power accepts that a working capital allowance may provide a better forward looking estimate of costs incurred.

697. The Authority is satisfied that Draft Decision Amendment 11 has been complied with.

Investment from Prior Periods

Western Power's Claim

698. In the proposed revisions to the access arrangement, Western Power proposed to add $244.43 million ($ real as at 30 June 2012) of the disallowed capital expenditure incurred during the first access arrangement to the opening capital base for the third access arrangement period. It described this expenditure as "speculative investment".

699. Western Power noted that its opening capital base at 1 July 2010 reflected a lower level of new facilities investment than actually occurred in the first access arrangement period as the capital base was reduced by $261.09 million ($ real as at 30 June 2009).

700. In the access arrangement information, Western Power noted that part of the $261.09 million related to specific projects that it accepts did not, and continued to not, pass the new facilities investment test and should not be added to the capital base. These projects amounted to $37.72 million and included:

- $18.4 million ($ real as at 30 June 2009) of inefficiencies associated with inadequate cost estimation across a number of specifically identified projects;
- $9.2 million ($ real as at 30 June 2009) of identified overcharging by contractors on a number of reviewed arrangements;
- $3.15 million ($ real as at 30 June 2009), which is a portion of the cost of the 490 MVA Wells terminal station transformer to connect the Boddington Gold Mine; and
- $6.97 million ($ real as at 30 June 2009) relating to the Busselton to Margaret River transmission line project.

701. Western Power described the remaining $223.4 million ($ real as at 30 June 2009) of investment incurred in the first access arrangement period as having been disallowed on the basis of specific findings being extrapolated to the whole investment. Western Power stated that it had adopted a similar approach to the speculative investment amount:

> "Our review of certain projects and programs has identified documentation that demonstrates that NFIT is satisfied for those projects and programs. Using a similar approach to that adopted by the Authority, we extrapolate those findings to establish that the full amount of disallowed expenditure that does not relate to the above mentioned identified projects satisfies NFIT."

702. Western Power then adjusted these values to "account for the time value of money and equivalent, in net present value terms" to June 2012 values. The total value it claimed should be added to the opening capital base for the third access arrangement period was $244.4 million ($ real as at 30 June 2012). This is shown in Table 58 below.

Table 58 Western Power's proposed investment from prior periods to be added to the opening capital base for the third access arrangement period

	2006/07	2007/08	2008/09	AA1 Total
$ million real at 30 June 2009				
Distribution speculative investment that satisfies NFIT	27.8	28.8	32.4	134.4
Transmission speculative investment that satisfies NFIT	37.1	42.2	55.1	89.0
Total speculative investment that satisfies NFIT	64.9	71.0	87.5	223.4
$ million real at 30 June 2012				
Distribution speculative investment that satisfies NFIT	40.6	46.2	60.2	147.1
Transmission speculative investment that satisfies NFIT	30.4	31.5	35.5	97.4
Total to be added to the capital base	71.0	77.7	95.7	244.4

703. In the access arrangement information, Western Power noted that it had comprehensively reviewed its governance and capital planning approach:

> "A particular area of focus has been the documentation that we use to demonstrate compliance with NFIT. This followed a number of observations and comments made by SKM that there was room for improvement in our documentation[164]. These comments formed the basis for the Authority's decision in relation to the level of inefficiency associated with our AA1 capital expenditure and we have sought to constructively respond to these matters.
>
> We examined in detail the documentation supporting the highest valued new facilities investment projects and programs to be undertaken in AA2. This review identified opportunities to improve how our project and program documentation demonstrates that the NFIT is satisfied. Importantly, however, the review did not identify any systemic issues associated with option choice and investment timing."[165]

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164 Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN, Attachment F2- Opinion by Sinclair Knight Mertz, 10 September 2009, p. 61.

165 Western Power, Access Arrangement Information, Appendix C - AA1 Speculative Investment, p. 4.

704. Western Power stated that its review of governance and planning processes included information relevant to the new facilities investment during the first access arrangement period because six of the specific projects reviewed included expenditure in the first access arrangement period and a number of the programs reviewed related to recurring programs of work (including pole management, bushfire management and reliability improvements), which also occurred during the first access arrangement period.

705. In Appendix C to the access arrangement information, Western Power provided a list of the projects and programs it had reviewed and the total expenditure for each expressed in real dollars at 30 June 2012:

- Distribution pole replacement ($104.4 million)
- Distribution improvement in service-reliability driven ($56.9 million)
- Bushfire management ($38.2 million)
- Low Value Asset Pool meters ($34.6 million)
- Neerabup - new terminal station ($51.8 million)
- Alinta cogen Southern Terminal ($32.7 million)
- Overhead Customer Service Connections ($42.2 million)

706. Western Power provided confidentially the documentation for two of these projects (Bushfire Management Plan and Overhead Customer Service Connections) and indicated the rest could be made available if required. Western Power considered that, given the representative nature of the projects reviewed, and that no systemic failures were identified, it was reasonable to assume that the whole of the disallowed expenditure satisfies the NFIT.

Submissions from first round of public consultation

707. Griffin considered that the investment from prior periods that did not meet the new facilities investment test should not be added to the regulated capital base.[166]

708. Landfill Gas and Power considered the NFIT was the appropriate mechanism and that if the investment meets the NFIT it should be included in the capital base.[167]

709. ERM Power considered there was not enough information provided to justify the inclusion of the $244.4 million in the opening capital base, and requested that the Authority determine whether Western Power's evidence was compelling enough to reverse the previous decision where the NFIT was not satisfied.[168]

710. Verve Energy considered that the previously rejected expenditure should be subject to the Authority's careful scrutiny to re-evaluate it against the NFIT.[169]

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166 November 2011, Griffin Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

167 December 2011, Landfill Gas and Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

168 December 2011, ERM Power Ltd, *Submission to the Economic Regulation Authority on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network.*

169 December 2011, Verve Energy, *Public Submission on the Call for Submission on Western Power's Proposed revisions to the Access Arrangement for the Western Power Network (AA3).*

711. The Office of Energy's submission noted the following:[170]

> "Given the general reasons for the initial disallowance, the Office supports the view that new information presented by Western Power in its third access arrangement proposal in relation to past new facility investment warrants thorough consideration by the Authority. The Office is of the view that Western Power has made some assumptions in relation to the value of the amount to be rolled into the capital base, based on extrapolated findings which the Authority should assess in greater detail.
>
> The Office supports the notion of assessment of speculative investment under the Access Code as such an assessment aligns itself with the notion of the ex-post assessment of investment by the Authority. The Office is of the view that the roll in of lost capital expenditure that can be shown to meet the speculative investment provisions will promote the efficiency of the business if the assessment is conducted in a transparent and consistent manner.
>
> It is noted that the Access Code provides little guidance as to the management and governance of the Speculative Investment Fund and the Office makes itself available to the Authority to assist with consideration of this previously unused provision."

712. In its submission to the public consultation process, Western Power considered that the statement in the Authority's Issues Paper to the effect that "Western Power has proposed to include in the opening capital base $244.4 million capital expenditure in AA1 that did not meet the requirement of the new facilities investment test" is incomplete. Western Power considered it should be noted that this expenditure is speculative investment. Western Power claimed that a review of documentation relating to specific projects and programs undertaken during the first access arrangement period showed that these investments satisfied the NFIT and could be added to the capital base.

Considerations of the Authority

713. At the last access arrangement review the Authority was hampered by a lack of necessary information to enable it to assess new facilities investment during the first access arrangement period against the requirements of the Code. As a result, the Authority's view on whether, and to what extent, the new facilities investment during the first access arrangement period met the efficiency test of section 6.52(a) of the Access Code included consideration of processes and practices within Western Power. Based on information provided by Western Power and advice from the Authority's technical consultant, the Authority's view was that the planning, design and governance processes of Western Power were, during the first access arrangement period, sufficiently deficient that the value of new facilities investment was in excess of the amount that would satisfy the efficiency test of section 6.52(a).

714. The amount excluded by the Authority in relation to investment during the first access arrangement comprised:

- An amount of $23.24 million (in dollar values of 30 June 2009) in respect of transmission projects that have been delayed or not proceeded, or amounts that should have been recovered through capital contributions:
  - $6.969 million (in dollar values of 30 June 2009) Busselton-Margaret River line project, which did not proceed;

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170 December 2011. Office of Energy, *Public Submission on the Issues Paper on Western Power's Proposed Amendments to its Access Arrangement for the Third Regulatory Period.*

  - $3.151 million (in dollar values of 30 June 2009) not recovered from a customer in relation to the 490MVA transformers at Wells Terminal;
  - $9.9 million (in dollar values of 30 June 2009) in relation to the North Country Region 330kV transmission project;
  - $3.25 million (in dollar values of 30 June 2009) for contribution in relation to the connection of the Newgen Neerabup Power Station, which Western Power had failed to properly account for.
- An amount of $126.87 million (in dollar values of 30 June 2009) in respect of inefficiencies arising from deficiencies in processes of cost estimation and overcharging by contractors:
  - $117 million (in dollar values of 30 June 2009) relating to inefficiency arising from poor cost estimation processes (five per cent of $910 million (net of previous adjustment) of investment in the transmission network and $1,436 million of distribution expenditure);
  - $9.56 million (in dollar values of 30 June 2009) inefficiency arising from overcharging by contractors.
- $110.97 million (in dollar values of 30 June 2009), being five per cent of capital expenditure net of the above adjustments and of gifted assets, reflecting the view of the Authority that inefficiencies had occurred in the selection and timing of augmentation projects as a result of deficiencies in methods for forecasting demand for network services and deficiencies in analysis of options for augmentation projects.

715. Western Power stated in its access arrangement information that, following the access arrangement review, it "sharpened" its focus on initiatives to improve strategic planning, delivery and compliance processes. As a result, a number of capital projects included in the forecasts for the second access arrangement period were deferred or cancelled. The Authority considers this to be further evidence that Western Power's governance processes were weak during the first access arrangement process and had resulted in inefficient expenditure.

716. The Authority does not agree with Western Power's claim in the proposed revisions to the access arrangement that the disallowed expenditure should now be regarded as "speculative investment" and reconsidered for inclusion in the capital base.

717. As noted in the Draft Decision, the Authority considers that Western Power has applied an interpretation of section 6.58 to conclude that any expenditure that does not meet the new facilities investment test must therefore be "speculative investment".

718. The Access Code defines "speculative investment amount" in relation to a "new facility" as, the amount determined under section 6.58 of the Access Code. "New facility" is defined in the Access Code as any capital asset developed, constructed or acquired to enable the service provider to provide covered services including assets required for the purpose of facilitating competition in retail markets for electricity.

719. Section 6.58 of the Access Code provides that the "speculative investment amount" (if any) for a new facility at any time is equal to:

- The "new facilities investment" (i.e. capital costs incurred by Western Power in developing, constructing and acquiring the "new facility");

- Minus any "recoverable portion" (i.e. any part of "new facilities investment" that has already been added to the capital base under section 6.57;
- Minus any amount for which a contribution has been, or is to be, provided by a user to the service provider;
- Minus any part of the speculative investment amount previously added to the capital base under section 6.60.

720. Section 6.60 provides that if a "speculative investment amount" was created for a new facility at a time and a determination of the capital base is made under section 6.44 at a later time, then any part of the speculative investment amount which satisfies the NFIT at the later time may be added to the capital base.

721. In the Draft Decision the Authority noted its concern that Western Power's interpretation of section 6.58 may not have been the intention of the drafters of the Access Code, particularly when read in conjunction with section 6.60(a) which applies where "a *speculative investment amount* was *created* for a *new facility*" (emphasis added). Put another way, the Authority was of the view that any speculative investment for the purpose of sections 6.58 and 6.60 of the Access Code should have been specifically identified as such at the time when the Authority determined whether the NFIT is satisfied. The Authority considers that it would be inconsistent with the Access Code objective to allow investment that was considered imprudent to be classified as speculative investment. The Authority was concerned that Western Power's construction of section 6.58 effectively enabled a service provider to re-open a properly made decision of the Authority under a previous access arrangement review.

722. Notwithstanding the above, in the Draft Decision the Authority agreed there is a lack of clarity in the wording of the Access Code. The Authority reviewed Western Power's proposal for compliance with the NFIT as set out below.

723. Each of the disallowed items is considered below.

Busselton-Margaret River Line Project

724. Western Power accepted that this expenditure should not be included in the regulatory capital base.

Transformers at Wells Terminal

725. Western Power accepted that this expenditure should not be included in the regulatory capital base.

North Country Region 330kV transmission project

726. In its final decision for the second access arrangement, the Authority disallowed $9.9 million ($ real as at 30 June 2009) relating to early planning and design costs for the north country region 330 kV transmission project. Western Power's third access arrangement period submission noted the expenditure was necessary to complete system modelling, options analysis, regulatory test preparation and design development.

727. The second access arrangement final decision noted that Western Power considered that the expenditure satisfied clauses 6.52(a) and 6.52(b)(iii) of the Access Code and that the project had "passed" the regulatory test and been given the conditional "go-

ahead" by the State Government, albeit with a modified scope. However, the Authority found:

> "Contrary to the submission from Western Power, other information available to the Authority indicates that it is uncertain whether the North Country Region 330kV transmission project will proceed as currently proposed and, if so, the timing of the project. In particular, advice from Western Power indicates that it is reviewing the project taking into account, inter alia, options for undertaking the project as a single stage or two stage project, revised forecasts of demand for network services, and interaction between the project and the proposed Eneabba to Karara transmission line project. For reason of the uncertainty with the project, the Authority considers that costs to date on this project should not be added to the capital base at this time."

728. Western Power's third access arrangement period submission[171] claimed that the project is now proceeding and the uncertainty no longer exists. The Authority noted that the Final Decision on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section) was published by the Authority on 27 January 2012. The pre-approved expenditure included all planning and design costs in relation to the Mid West Energy Project (Southern Section), which the Authority determined to be efficient.

729. For the purposes of the Draft Decision, the Authority adjusted Western Power's proposed capital expenditure in relation to the Mid West Energy Project (Southern Section) to be consistent with the amount approved by it on 27 January 2012. The Authority does not consider any expenditure over and above the amount set out in that decision meets the new facilities investment test.

730. Any costs that relate to the section of line between Eneabba and Geraldton should not be added to the capital base at this time as there is no certainty at this stage that the northern section of the project will proceed. If the project does proceed in the future, Western Power would need to provide sound evidence that any such costs were directly relevant to the final design of the project.

Newgen Neerabup Power Station

731. Western Power did not provide any evidence as part of its third access arrangement period proposal for why this should be included in its capital base. In the Draft Decision, the Authority confirmed its previous view that Western Power failed to account properly for a $3.25 million contribution in relation to the connection of the Newgen Neerabup Power Station and that it should be excluded from the regulatory capital base.

Inefficiencies in Cost Estimation Processes

732. In its final decision for the second access arrangement, the Authority excluded $117 million relating to inefficiency arising from poor cost estimation processes (five per cent of $910 million (net of the adjustments noted above) of investment in the transmission network and $1,436 million of distribution expenditure). The five per cent reduction was based on a study carried out by Sinclair Knight Mertz (**SKM**) for Western Power and provided to the Authority following the Draft Decision. SKM identified 65 capital projects of value greater than $2 million that SKM considered were potentially adversely affected by deficiencies in cost estimation processes. SKM took the view that poor cost estimation processes may give rise to an "inefficiency

171 Western Power, Access Arrangement Information, Appendix C - AA1 Speculative Investment, p. 7.

factor" of a maximum of five per cent of the project value. SKM applied this factor to the total value of all projects identified by it as being affected by estimation problems to derive a value of inefficiency of $18 million (five per cent of a total value of projects of $351 million).

733. In its AA2 final decision, the Authority considered that SKM's estimate of the extent of inefficiency arising from deficiencies in cost estimation processes may not fully capture the extent of this inefficiency. SKM determined the value as five per cent of a value of significant capital projects (greater than $2 million in value) for which the final cost exceeded the cost estimate by greater than 10 per cent, or original cost estimates could not be located. The Authority did not consider there was any reason why estimates of the extent of inefficiency arising from deficiencies in cost estimation should be so constrained. Rather, the Authority considered such inefficiencies may arise regardless of the difference between an original cost estimate and the final cost of a project (for example, a poor original cost estimate may drive an inefficiently high cost outcome), and may arise regardless of the size of the capital project. The Authority accepted the value of five per cent applied by SKM as the level of inefficiency arising from deficiencies in cost estimation processes was appropriate, but applied it to total investment for the transmission network and to that part of investment in the distribution network that is internally funded by Western Power (i.e., excluding gifted assets).

734. In its access arrangement information, Western Power stated that "the Authority applied a 5 per cent reduction to the whole of the first access arrangement expenditure based on a lack of supporting information from Western Power". Western Power noted that it had reconsidered the issue of supporting information and that its subsequent review of second access arrangement projects and programs that are relevant to the first access arrangement projects found that inefficiencies due to cost estimation were not apparent. Western Power noted "we have also considered our programs of work that will continue throughout the periods (such as bushfire management and wood pole replacement) that have already been regarded as complying with NFIT".

735. Western Power went on to state that "given these recurrent programs of work do not suffer from cost inefficiencies in relation to cost estimation, we believe it is reasonable to apply the outcomes of our documentary review across the expenditure not subject to specific disallowances." Based on this view, Western Power proposed that the whole of the $117 million should be added to the opening capital base for the third access arrangement period.

736. In its final decision for the second access arrangement, the Authority noted that the report submitted by Western Power from SKM addressing the Authority's draft determination on the level of inefficiency in the first access arrangement period's new facilities investment appeared to indicate that SKM had access to more information on particular capital projects than was made available to the Authority, despite the Authority having previously advised Western Power of deficiencies in information provided with the proposed access arrangement revisions and issuing Western Power with a statutory notice requiring further relevant information to be provided.

737. The Authority noted in the Draft Decision that, given the level of scrutiny of this matter at the time of the second access arrangement review, the Authority was surprised that Western Power was now seeking to put new information forward in relation to its cost estimation processes for the first access arrangement period.

738. The Authority also noted that Western Power was incorrect in its statement that "the Authority applied a 5 per cent reduction to the whole of the first access arrangement expenditure based on a lack of supporting information from Western Power". As noted above, the adjustment was based on the SKM report findings with the only difference being that it was applied across the total expenditure program rather than restricted to certain types of expenditure.

739. The SKM report provided by Western Power following the second access arrangement period draft decision served to confirm the Authority's view that Western Power's cost estimation process for the first access arrangement period had significant weaknesses, which led to inefficiencies. The information provided by Western Power in its access arrangement information did not change the Authority's view. Therefore, the Authority did not accept Western Power's proposal that $117 million ($ values of 30 June 2009) should be added to the opening capital base for the third access arrangement period.

Overcharging by Contractors

740. Western Power accepted that this expenditure was inefficient and should not be included in the regulatory capital base.

Inefficiencies in Planning, Design and Governance

741. In its final decision for the second access arrangement period, the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of deficiencies in forecasting of demand for services, deficiencies in consideration of all relevant options for augmentations, and over-engineering of augmentation designs. In particular, the Authority noted information provided by Western Power subsequent to the draft decision confirming this view, including the following:

- Western Power not using best-practice design software for the design of transmission lines that would facilitate more effective economic optimisation of transmission line design.[172]
- An absence of standard designs and guidelines for distribution assets.[173]
- Unusually restrictive design specifications for equipment, limiting the number of potential suppliers.[174]
- A lack of rigour in assessing options for network augmentations and documenting these assessments.[175]

742. Western Power was not able to provide the Authority with sufficient information to enable it to assess the extent of inefficiency on a project-by-project basis. However, for the reasons set out above, the Authority took the view that the extent of the inefficiency was greater than a nominal amount and in the order of 5 per cent.

743. In its access arrangement information, Western Power referred to the adjustment made by the Authority of $110.97 million in relation to inefficiencies it determined had

172 Western Power submission of 10 September 2009, Attachment F2: pp. 42, 43.
173 Western Power submission of 10 September 2009, Attachment F2: p. 44.
174 Western Power submission of 10 September 2009, Attachment F2: p. 48.
175 Western Power submission of 10 September 2009, Attachment F2: p. 61.

occurred in relation to the planning, design and governance of network augmentations:

> "Western Power recognises that the determination of the Authority was based on the material it had before it at that time. However, our subsequent review of the governance and capital planning documentation outcomes for a sample of AA2 projects that are relevant to AA1 demonstrates that our options assessment and works choice is consistent with efficiently minimising costs (as defined in the Code with its emphasis on good electricity industry practice) and satisfying the NFIT requirements of the Access Code."

744. In the Draft Decision, the Authority did not consider that the information included in Western Power's third access arrangement period proposal (as outlined in paragraphs 703 to 706 above) addressed the weaknesses outlined in paragraph 741 above. Therefore, the Authority did not alter its view, as set out in the second access arrangement final decision, that the expenditure did not meet then new facilities investment test.

Overall conclusion in Draft Decision

745. Western Power noted in its access arrangement information that, in response to the criticism from the Authority and the Authority's technical adviser, it "sharpened" its focus on initiatives to improve strategic planning, delivery and compliance processes.[176] As a result, a number of capital projects included in the forecasts for the second access arrangement period were deferred or cancelled.

746. In the Draft Decision, the Authority took the view that any improvements made by Western Power to its processes since the last access arrangement review would not change the findings of the Authority in relation to past expenditure. Consequently, the Authority did not agree in the Draft Decision that the $244.43 million ($ real as at 30 June 2012) should now be added to Western Power's opening capital base for the third access arrangement period.

747. The Authority accordingly required the following amendment to the proposed revised access arrangement.

> **Draft Decision Amendment 12**
>
> Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

748. In response to the Draft Decision, Western Power has not accepted the Authority's required amendment in full and put forward further arguments for including an amount of $151.7 million ($ real as at 30 June 2012) in the opening capital base.

749. Western Power's amended access arrangement information states that the Authority "did not incorporate $5 million for planning and design of the Mid West Energy Project (Southern Section), despite acknowledging in its draft decision that this amount was efficient".

750. Western Power appears to have misunderstood the intention of the Authority. As noted in the Draft Decision, the Authority adjusted Western Power's proposed capital expenditure in relation to the Mid West Energy Project (Southern Section) to be

176 Western Power Access Arrangement Information, p. 62.

consistent with the amount approved by it on 27 January 2012 in relation to the new facilities investment test application. The pre-approved expenditure included all planning and design costs in relation to the project that the Authority determined to be efficient. This included some amounts in relation to the early planning work conducted during the first access arrangement period, which was of relevance to the final project. Adjusting Western Power's third access arrangement submission to be consistent with the Mid West Energy Project (Southern Section) new facilities investment determination ensures that all of the amounts determined to be efficient are included in the capital base. An amount of $6.5 million has been added to the opening capital base (as set out in Table 57) reflecting the planning and design costs incurred in the first access arrangement period.

751. In the amended access arrangement information, Western Power refers to paragraph 489 of the Draft Decision, which sets out some weaknesses identified by the Authority during its review of the second access arrangement in 2009. Western Power has interpreted this to be a complete list of the weaknesses found and has assessed a number of specific projects against the list. Then, using a combination of its assessment of whether any of the four weaknesses applied to each project and extrapolation of the costs of each project, Western Power has arrived at an amount of $106.5 million, which it considers falls outside the parameters of the Authority's adjustment.

752. Western Power has misstated the basis of the Authority's adjustment. As paragraph 489 of the Draft Decision sets out, in its final decision for the second access arrangement period, the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of deficiencies in forecasting of demand for services, deficiencies in consideration of all relevant options for augmentations, and over-engineering of augmentation designs. A list of some of the weaknesses identified was included by way of illustration, but was not presented as a complete list. It is not appropriate to use this list of four items and apply it to specific schemes.

753. As noted in the Draft Decision, Western Power was not able to provide the Authority with sufficient information to enable it to assess the extent of the inefficiency on a project-by-project basis. The Authority took the view that the extent of the inefficiency was greater than a nominal amount and in the order of 5 per cent. The total adjustment, for the entire capital program, amounted to $119.87 million (in dollar values of June 2012).[177]

754. Based on its analysis of a sub-set of projects using the analysis and extrapolation techniques outlined above, Western Power is proposing that $106.5 million, or 89 per cent of the total amount adjusted by the Authority should be added to the capital base. The Authority does not consider the analysis put forward by Western Power substantiates a reduction in the amount of expenditure disallowed at the last access arrangement review.

755. The Authority, therefore, retains the requirement for Draft Decision Amendment 12.

[177] This equates to $110.97 million (in dollar values of 30 June 2009).

Required Amendment 9

Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

Capital Base at the Commencement of the Third Access Arrangement Period

756. In the Draft Decision, the Authority calculated revised values of the capital base for the transmission and distribution networks at 30 June 2012. This was done in accordance with the Authority's Draft Decision determination on the value of new facilities investment in the second access arrangement period that may be added to the capital base under section 6.51A of the Access Code, and on the value of redundant assets to be subtracted from the capital base.

757. The Authority's calculation of the revised capital base values in its Draft Decision are shown in Table 59 and Table 60 below.

Table 59 Draft Decision capital base at 30 June 2012 for the transmission network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		2,350.0	2,467.5	2,538.3
New facilities investment		198.3	151.6	146.1
Asset disposals		(5.5)	(0.3)	0.0
Depreciation		(75.3)	(80.5)	(91.1)
Accelerated depreciation		0.0	0.0	0.0
Closing asset base	2,350.0	2,467.5	2,538.3	2,593.2

Table 60 Draft Decision capital base at 30 June 2012 for the distribution network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		3,042.3	3,319.1	3,584.4
New facilities investment		436.6	437.5	537.6
Asset disposals		(0.9)	0.0	0.0
Depreciation		(154.7)	(168.2)	(186.0)
Accelerated depreciation		(4.2)	(4.1)	(4.0)
Closing asset base	3,042.3	3,319.1	3,584.4	3,932.0

758. Accordingly, the Authority required the following amendment.

Draft Decision Amendment 13

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 59 and Table 60 above.

759. In response to the Draft Decision, Western Power notes it has continued to apply the roll forward method to determine the opening capital base but has made adjustments to adopt a mid-year inflation indexation assumption when adding expenditure for the second access arrangement period. As discussed above, Western Power has not accepted the Authority's amendments in relation to capital investment during the first and second access arrangement periods. As a result, Western Power's revised

revenue model results in different values for the opening capital base for 1 July 2012 compared with the Draft Decision.

760. Western Power's revised proposed opening capital base is set out below.

Table 61 Western Power's revised proposed capital base at 30 June 2012 for the transmission network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		2,321.4	2,443.8	2,535.0
New facilities investment (AA2)		202.9	171.1	146.5
Investment from prior periods				53.5
Asset disposals		(6.1)	(0.3)	0.0
Depreciation		(74.4)	(79.6)	(90)
Accelerated depreciation		0	0	0
Closing asset base	2,321.4	2,443.8	2,535.0	2,645.1

Table 62 Western Power's revised proposed capital base at 30 June 2012 for the distribution network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		3,005.2	3,288.4	3,561.4
New facilities investment (AA2)		441.1	443.2	485.1
Investment from prior periods				95.4
Asset disposals		(0.9)	0	0
Depreciation		(152.8)	(166.1)	(183.7)
Accelerated depreciation		(4.2)	(4.1)	(4.0)
Closing asset base	3,005.2	3,288.4	3,561.4	3,954.2

761. As noted above, Western Power has modified its methodology for inflating capital expenditure during the second access arrangement period when adding it to the capital base. Western Power's model assumes that capital investment during the second access arrangement occurs mid-year for the purposes of applying inflation. Western Power considers this better reflects the costs incurred during those years.

762. Western Power notes that capital costs are incurred throughout the year, rather than at the end of the year. Western Power considers it is appropriate to adjust for inflation on the basis that an end of year timing assumption does not take into account the effect of inflation on costs incurred during the year, and results in the level of indexation in 30 June 2012 prices being understated. Western Power considers this amendment will remove the incentive to delay capital investment to the end of the financial year.

763. Western Power has applied the CPI (weighted average of eight capital cities) to determine the amount of capital expenditure to be included in the rolled-forward capital base for each year of the second access arrangement, including an amount for half year inflation using the following formula:

$$\text{Half year inflation} = (\text{full year inflation}_{\text{June to June}})^{1/2}$$

764. Western Power has not applied its revised methodology when forecasting expenditure included in the notional capital base for the third access arrangement period. Western Power considers it is appropriate to apply different approaches because "the opening

capital base is established based on actual costs incurred during the period whereas forecast costs incorporate assumptions about timing".

765. Western Power's revised inflation values are set out in Table 63 below together with the values used in the revised proposed revisions to the access arrangement. Western Power states that it has used actual CPI data published by the Australian Bureau of Statistics for the June quarter where available, or otherwise, the forecast CPI data from the Reserve Bank of Australia's Statement on Monetary Policy.

Table 63 Western Power's revised proposed capital base at 30 June 2012 for the distribution network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012 (forecast)
Western Power revised inflation values (May 2012)				
June CPI	167.0	172.1	178.3	
Inflation	1.46%	3.05%	3.60%	1.25%
Western Power inflation values (September 2011)				
June CPI	167.0	172.1	178.3	
Inflation	1.46%	3.05%	3.60%	2.50%

766. The Authority does not consider Western Power's proposed new methodology for inflating the opening capital base is appropriate. The proposed methodology appears to be a variation on its original proposal to adopt a mid-year timing assumption in relation to capital expenditure by adjusting the expenditure in each year for the time value of money for six months and adding this amount to the capital base.

767. As discussed in paragraphs 684 to 694, in the Draft Decision the Authority rejected Western Power's proposal to include a "time value of money adjustment" for mid-year capital expenditure on the basis that it considered Western Power had been inconsistent in its proposed modelling changes as it did also not propose that the Authority should account for revenue collection on a mid-year basis. The Authority considers the arguments Western Power is now putting forward regarding the inflation of the opening capital base are also inconsistent as similar arguments could apply to revenue collection as it is also received throughout the year. The Authority considers, as with its previous proposal regarding the treatment of capital expenditure on a mid-year basis, that this inconsistency in Western Power's modelling change would result in it receiving an arbitrary benefit at the expense of customers, contrary to the Code objective.

768. The Authority, therefore, requires that capital expenditure incurred during the second access arrangement must be inflated using year-end inflation rates as is the case in the current access arrangement and consistent with all other cash flows in the determination of target revenue.

> **Required Amendment 10**
>
> The opening capital base for 1 July 2012 in the proposed revised access arrangement must be inflated using the same methodology as the current access arrangement and must not include the additional half year inflation in relation to expenditure during the second access arrangement proposed by Western Power.

769. The June 2012 CPI has now been published and is 180.4, which results in actual inflation for the year of 1.18%. The Authority has used the actual CPI index to calculate the opening capital base.

770. The Authority has calculated revised values of the capital base for the transmission and distribution networks at 30 June 2012 in accordance with the Authority's determination under the Final Decision on the value of new facilities investment in the second access arrangement period that may be added to the capital base under section 6.51A of the Access Code, and on the value of redundant assets to be subtracted from the capital base.

771. The Authority's calculation of the revised capital base values in its Final Decision are shown in Table 64 and Table 65 below.

Table 64 Final Decision capital base at 30 June 2012 for the transmission network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		2,319.7	2,435.1	2,504.9
New facilities investment		195.2	149.5	139.8
Asset disposals		-5.4	-0.3	0.0
Depreciation		-74.4	-79.5	-90.0
Accelerated depreciation		0.0	0.0	0.0
Closing asset base	2,319.7	2,435.1	2,504.9	2,554.7

Table 65 Final Decision capital base at 30 June 2012 for the distribution network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		3,003.0	3,276.5	3,538.1
New facilities investment		431.2	431.7	505.1
Asset disposals		-0.9	-0.0	0.0
Depreciation		-152.7	-166.0	-183.6
Accelerated depreciation		(4.1)	(4.1)	(3.9)
Closing asset base	3,003.0	3,276.5	3,538.1	3,855.6

Required Amendment 11

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 64 and Table 65 above.

Forecast Capital Base for the Third Access Arrangement Period

Access Code Requirements

772. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated in respect of an amount of forecast new facilities investment that at the time of inclusion is reasonably expected to satisfy the test in section 6.51A of the Access Code when the forecast new facilities investment is forecast to be made.

773. The effect of section 6.51 and 6.51A is that Western Power may notionally add forecast new facilities investment to the capital base in each year of the third access arrangement period to the extent that the forecast amount either:

- is reasonably expected to satisfy the new facilities investment test; or
- the Authority otherwise approves the forecast amount being added to the capital base if it has been (or is expected to be) financed by a contribution meets the requirements of the first part of the new facilities investment test (the efficiency test of section 6.52(a) of the Access Code), and the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of addition of the amount to the capital base.

Proposed Revisions

774. For the purposes of determining target revenue for the third access arrangement period, Western Power has forecast values of the capital base for the transmission and distribution networks at the commencement of each year.

775. Western Power proposes to only take into account, for the purposes of determining target revenue, forecast new facilities investment that is reasonably expected to satisfy the new facilities investment test. Western Power proposes to not add to the capital base any new facilities investment that is financed by contributions.

776. Western Power had forecast in its proposed revisions (September 2011) total capital expenditure (net of capital contributions) of $4,870.4 million over the five year third access arrangement period, with $1,838.9 million required for the transmission network and $3,031.5 million for the distribution network. Western Power forecast that its total capital base would be around $10,414.8 million by the end of the third access arrangement period, with a closing value for the transmission network and distribution network of $4,209.8 million and $6,205.0 million, respectively. Western Power's proposed forecast opening and closing values of the capital base for each year of the third access arrangement period for the transmission and distribution network are shown in Table 66 and Table 67.

Table 66 Western Power's initial proposed forecast transmission network capital base (real $ million at 30 June 2012)[178]

	2012/13	2013/14	2014/15	2015/16	2016/17	5 years
Opening asset value	**2,840.8**	**3,102.2**	**3,277.1**	**3,526.2**	**3,931.8**	**2,840.8**
New facilities investment[179]	337.5	255.9	340.0	503.3	390.5	1,827.2
Inventory	0.4	9.0	3.6	(1.6)	0.3	11.7
Mid-year timing assumption	14.6	11.0	14.7	21.7	16.9	78.9
Depreciation	(91.2)	(100.9)	(109.2)	(117.8)	(129.6)	(548.7)
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0	0.0
Closing asset base	**3,102.2**	**3,277.1**	**3,526.2**	**3,931.8**	**4,209.8**	**4,209.8**

Table 67 Western Power's initial proposed forecast distribution network capital base (real $ million at 30 June 2012)[180]

	2012/13	2013/14	2014/15	2015/16	2016/17	5 years
Opening asset value	**4,257.2**	**4,614.4**	**5,037.7**	**5,452.5**	**5,832.5**	**4,257.2**
New facilities investment[181]	543.6	621.5	635.8	610.5	613.8	3,025.2
Inventory	0.5	2.4	2.3	(1.2)	2.4	6.4
Mid-year timing assumption	23.5	26.8	27.4	26.4	26.5	130.6
Depreciation	(206.7)	(226.9)	(250.8)	(255.7)	(270.2)	(1,210.3)
Accelerated depreciation	(3.4)	(0.5)	0.0	0.0	0.0	(3.9)
Closing asset base	**4,614.4**	**5,037.7**	**5,452.5**	**5,832.5**	**6,205.0**	**6,205.0**

777. Western Power forecast substantial real increases in new facilities investment over the actual costs incurred in the current access arrangement period. These increases were attributed by Western Power to:

- improving the safety of the network through increased pole replacement and reinforcement rates and replacing unsafe customer service connections; and

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178 Revised access arrangement information, Section 10.2.9, Table 65. Revised access arrangement information, Section 10.3.1, Tables 66 and 67.

179 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

180 Revised access arrangement information, Section 10.2.9, Table 65. Revised access arrangement information, Section 10.3.2, Tables 68 and 69.

181 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

- cope with maintaining network security and growth, particularly growth in peak demand.

778. Western Power acknowledged that its pole failure rate is the highest in Australia.[182] Its wood pole failure rate has been the subject of an order to repair by the Energy Safety Office. As a result, Western Power proposed to reinforce and replace an average of 33,000 poles per year at a cost of $748 million. Western Power estimated that its wood pole management plan would take 20 years of elevated investment before pole replacement is at a 'sustainable rate'.[183]

Draft Decision

779. In the Draft Decision, the Authority did not approve Western Power's forecast capital expenditure. The reasons for this are set out below under "Considerations of the Authority". The Authority calculated revised values of the notional capital base for the third access arrangement period in accordance with the Authority's determinations under the Draft Decision on whether the forecast new facilities investment may, under section 6.51 of the Access Code, be taken into account in determination of total costs and target revenue.

780. The Authority determined a revised notional capital base at the end of the third access arrangement period (30 June 2017) for the transmission network of $3,417.2 million compared with a value of $4,209.8 million proposed by Western Power (in dollar values of 30 June 2012). For the distribution network, the Authority determined a notional capital base of $5,599.1 million compared with Western Power's proposal of $6,205.0 million (in dollar values of 30 June 2012).

781. A summary of the values determined by the Authority are set out in Table 68 and Table 69 below.

[182] Revised Access Arrangement Information, Section 8.2.1, p. 176.

[183] Revised Access Arrangement Information, Section 8.2.1, p. 176.

Table 68 Draft Decision forecast transmission network capital base (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	5 years
Opening asset value	**2,593.2**	**2,781.8**	**3,041.0**	**3,139.2**	**3,256.6**	**2,593.2**
New facilities investment[184]	273.8	350.5	199.6	223.4	271.0	1,318.3
Inventory	0.0	0.0	0.0	0.0	0.0	0.0
Mid-year timing assumption	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	(86.4)	(93.9)	(102.4)	(107.8)	(113.8)	(504.3)
Accelerated depreciation	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0
Equity raising costs	1.2	2.6	1.0	1.7	3.4	**9.9**
Closing asset base	**2,781.8**	**3,041.0**	**3,139.2**	**3,256.6**	**3,417.2**	**3,417.2**

Table 69 Draft Decision forecast distribution network capital base (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	5 years
Opening asset value	**3,932.0**	**4,247.2**	**4,618.0**	**4,971.4**	**5,290.3**	**3,932.0**
New facilities investment[185]	513.0	583.2	587.1	556.0	559.0	2798.3
Inventory	0.0	0.0	0.0	0.0	0.0	0.0
Mid-year timing assumption	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	(197.1)	(215.3)	(236.7)	(239.1)	(251.0)	(1,139.2)
Accelerated depreciation	(3.4)	(0.5)	0.0	0.0	0.0	(3.9)
Equity raising costs	2.9	3.4	3.0	1.9	0.9	**12.1**
Closing asset base	**4,247.2**	**4,618.0**	**4,971.4**	**5,290.3**	**5,599.1**	**5,599.1**

184 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

185 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

Western Power's response to the Draft Decision

782. In response to the Draft Decision, Western Power has increased its forecast total capital expenditure (net of capital contributions) by $307.9 million over the third access arrangement period. The value Western Power has now proposed for the transmission network is slightly less ($1,804.3 million compared with $1,827.2 million) while the amount for the distribution network has increased ($3,356 million compared with $3,025.2 million).

783. Western Power's revised forecast is that its total capital base will be around $10,053.7 million by the end of the third access arrangement period, with a closing value for the transmission network and distribution network of $3,924.1 million and $6,129.6 million, respectively. Western Power's revised proposed forecast opening and closing values of the capital base for each year of the third access arrangement period for the transmission and distribution network are shown in Table 70 and Table 71 below.

Table 70 Western Power's revised proposed forecast transmission network capital base (real $ million at 30 June 2012)[186]

	2012/13	2013/14	2014/15	2015/16	2016/17	5 Years	Draft Decision
Opening asset value	**2,645.1**	**2,860.9**	**3,133.1**	**3,291.6**	**3,568.9**	**2,645.1**	2,593.2
New facilities investment[187]	303.1	368.5	264.5	390.4	477.8	1,804.3	1,318.3
Inventory	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-year timing assumption	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	(87.3)	(96.3)	(105.9)	(113.1)	(122.6)	(525.2)	(504.3)
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equity raising costs	0.0	0.0	0.0	0.0	0.0	0.0	9.9
Closing asset base	**2,860.9**	**3,133.1**	**3,291.6**	**3,568.9**	**3,924.1**	**3,924.1**	3,417.2

186 Amended Access Arrangement Information, Revenue Model.

187 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

Table 71 Western Power's revised proposed forecast distribution network capital base (real $ million at 30 June 2012)[188]

	2012/13	2013/14	2014/15	2015/16	2016/17	5 Years	Draft Decision
Opening asset base	**3,954.2**	**4,386.7**	**4,846.0**	**5,289.9**	**5,717.2**	**3,954.2**	3,932.0
New facilities investment[189]	634.1	679.7	688.2	676.9	677.1	3,356.0	2,798.3
Inventory	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Redundant assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	(198.2)	(219.9)	(244.2)	(249.6)	(264.8)	(1,176.7)	(1,139.2)
Accelerated depreciation	(3.4)	(0.5)	0.0	0.0	0.0	(3.9)	(3.9)
Equity raising costs							12.1
Closing asset base	**4,386.7**	**4,846.0**	**5,289.9**	**5,717.2**	**6,129.6**	**6,129.6**	5,599.1

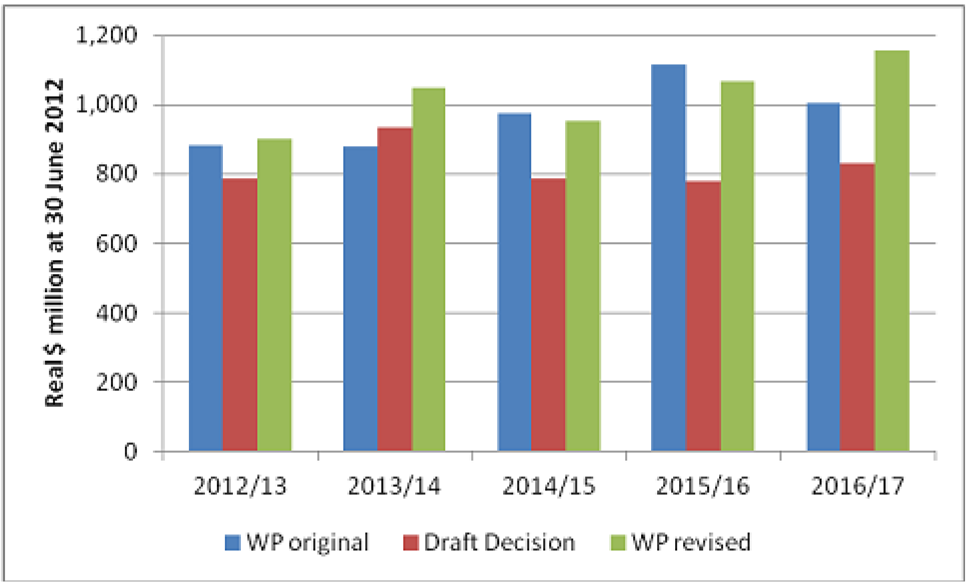
784. Although Western Power has made some reductions to elements of its forecast capital expenditure compared with its initial proposal, it has significantly increased its forecast volume of wood pole reinforcements which has resulted in a net increase overall in capital expenditure of around $255 million compared with its initial expenditure forecast.

785. Figure 7 provides a graphical presentation of the total (transmission and distribution) new facilities investment initially proposed by Western Power, the Draft Decision and Western Power's revised proposed expenditure net of capital contributions, inventory and mid-year timing assumption for each year of the third access arrangement period.

188 Amended Access Arrangement Information, Revenue Model.

189 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

Figure 7 Total capital expenditure (real $ million at 30 June 2012)



786. Western Power's revised proposed capital base is further discussed under "Considerations of the Authority".

Submissions

787. In its submission to the first round of public consultation, Synergy noted Western Power's stated reasons in support of its ability to deliver the capital expenditure program during the third access arrangement period but queried whether it had seen the project and process improvements during the current access arrangement referred to by Western Power. Synergy requested the Authority to assess Western Power's claims in considering its ability to deliver the investment proposal.[190]

788. Landfill Gas and Power's submission to the first round of public consultation viewed the magnitude of the pole replacement program to be such that it should be addressed at a higher independent level and not be part of the access arrangement considerations.[191]

789. Alinta's first round public consultation submission noted the size of the proposed third access arrangement period capital expenditure program in light of Western Power's significant underspend in the current access arrangement and queried Western Power's internal resources to meet the large expansion of its capital expenditure program. Alinta raised the issue of the AER (in National Electricity Rules regulatory decisions) taking prior period underspend/overspend into account when approving capital expenditure going forward and requested the Authority to assess Western Power's ability to deliver the capital expenditure program.[192]

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190 November 2011, Synergy, *Public Submission to the Economic Regulation Authority – Western Power's Proposed Revisions to the Access Arrangement.*

191 December 2011, Landfill Gas and Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

192 December 2011, Alinta Energy (Australia) Pty Ltd, *Public Submission on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network.*

790. The submission from the Chamber of Commerce and Industry (CCI) in relation to the first round of public consultation, noted that the most recent Commonwealth Bank-CCI Survey of Business Expectations showed a large proportion of businesses (22 per cent) rated energy infrastructure as an area in need of attention.[193]

> "For business it is particularly important that Western Power is able to invest in the electricity network in support of WA's growth while also promoting the Electricity Networks Access Code 2004 objective. This balance is unlikely to be achieved through the ERA's process alone and requires strategic planning from the State Government to recognise a wider range of benefits from investment in electricity networks.
>
> CCI forecasts economic growth in WA to rise towards 7 per cent in 2012-13, led by large business investment in the resources sector. While these figures reflect some activity outside the Western Power Network, many of the State's growth areas are closely linked to this network. This underlines the need for a forward looking approach to the AA3 investment program. In this context we are broadly supportive of a revenue requirement for Western Power that recognises this need for growth and enables appropriate, efficient and realistic investment in the network."

791. During the second round of consultation, Alinta, WACOSS and the WAMEU supported the Authority's reduction of Western Power's initial capital expenditure proposals in the Draft Decision.

792. Alinta believes that the Authority has made reasonable decisions in the Draft Decision in relation to Western Power's capital expenditure forecasts. Alinta noted that Western Power had previously underspent capital expenditure relative to the allowed revenue and that the allowed capital expenditure in the Draft Decision 'is likely to ensure that users and consumers of electricity do not pay for excessive capital expenditure not warranted by demand at the current point of time.'[194]

793. Alinta considers that the Access Code allows the Authority and Western Power to take a cautious approach for considering demand related capital expenditure, given that should demand warrant expenditure to be brought forward, Western Power can utilise the New Facilities Investment Test (NFIT) provisions in the Access Code.[195]

794. WACOSS also supported the Authority's reasons for being conservative in determining reasonable capital expenditure forecasts, considering that Western Power has consistently over-estimated its requirement in the past and appears to have done this for the third access arrangement period. WACOSS also considers to that the estimation techniques are within Western Power's control and therefore it is appropriate to carefully scrutinise them and take a conservative approach in setting forecasts in order to sharpen Western Power's incentives to better forecast and plan its capital expenditure program.[196]

795. WACOSS considers that it would be useful for the Authority to benchmark the efficiency of Western Power's capital projects against interstate comparators to provide users and other interested parties with insights into the efficiency of Western Power's capital expenditure.[197]

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193 December 2011, Chamber of Commerce and Industry Western Australia, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

194 May 2012, Alinta, Submission on the Authority's Draft Decision, p. 2.

195 May 2012, Alinta, Submission on the Authority's Draft Decision, p. 3.

196 May 2012, WACOSS, Submission on the Authority's Draft Decision, p. 9.

197 May 2012, WACOSS, Submission on the Authority's Draft Decision, p. 10.

796. WACOSS also considers that there is scope for a capital expenditure efficiency dividend during the third access arrangement period. WACOSS believes this is justified by project management efficiencies and new technological developments and considers that Western Power needs an incentive to seek out these savings.[198]

797. The WAMEU considered that the approach of the Authority of assessing capital expenditure on both a global basis and sector (transmission, distribution) basis is good regulatory practice for a consolidated entity.[199] However, the WAMEU considered that the Authority has not considered an external benchmarking process from an affordability review or from an availability of funding to deliver the capital expenditure.[200]

798. However, the WAMEU considered that the capital expenditure allowed in the Authority's Draft Decision reasonably reflects the actual capital expenditure during the current access arrangement period under similar growth conditions. The WAMEU did raise a concern that the analysis on capital expenditure did not include any benchmarking to identify if the overall capital expenditure allowance is efficient when compared to other similar network operations. The WAMEU considered that if the comparisons are not flattering, the Authority must apply stronger drivers to incentivise efficiency and productivity gains.[201]

Considerations of the Authority

799. The Authority has considered Western Power's calculation of the capital base for each of the transmission and distribution networks and the extent to which these calculations are consistent with the requirements of the Access Code. These considerations include the following:

- the general method applied in calculating the capital base; and
- determination of notional values of the capital base in each year of the third access arrangement period taking into account the assessment of forecast capital expenditure against the requirements of section 6.51A of the Access Code, and forecast values of depreciation and redundant assets.

General Method

800. Consistent with the method it has used to establish the opening capital base for the third access arrangement period, Western Power has calculated the capital base for each of the transmission and distribution networks using a roll-forward method, applied in a manner consistent with the method contemplated in the note to section 6.48 of the Access Code.

801. The roll-forward method has been favoured by utility regulators throughout Australia and is the method mandated for electricity transmission and distribution networks of the NEM under Chapters 6A and 6 of the NER.

802. The Authority is satisfied that the method used by Western Power is consistent with the Code objective.

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198 May 2012, WACOSS, Submission on the Authority's Draft Decision, p. 10.
199 May 2012, WAMEU, Submission on the Authority's Draft Decision, p. 34.
200 May 2012, WAMEU, Submission on the Authority's Draft Decision, p. 32.
201 May 2012, WAMEU, Submission on the Authority's Draft Decision, pp. 39-40.

Notional Capital Base over the Third Access Arrangement Period

Application of the Section 6.51A Test to Forecast New Facilities Investment

803. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated in respect of an amount of forecast new facilities investment that at the time of inclusion is reasonably expected to satisfy the test in section 6.51A of the Access Code when the investment is forecast to be made.

804. Consistent with the approach adopted for the current access arrangement period, Western Power proposes to only take into account, for the purposes of determining target revenue, forecast capital expenditure that is reasonably expected to satisfy the new facilities investment test. Western Power proposes to not add to the capital base any capital expenditure that is financed by contributions.

805. Western Power has determined amounts of forecast capital expenditure to be notionally added to the capital base by deriving a total amount of forecast capital expenditure and subtracting a forecast of capital contributions.

806. The approach taken by the Authority to assessing the forecast of new facilities investment and the amount of this forecast investment claimed by Western Power to satisfy the new facilities investment test has been to:

    - assess whether the forecast new facilities investment is reasonably expected to satisfy the efficiency test under section 6.52(a) of the Access Code; and
    - assess whether Western Power has made a reasonable forecast of the amount of new facilities investment that will satisfy the new facilities investment test in section 6.52 (a) and (b) and is not otherwise financed by capital contributions.

807. The Authority has addressed the forecast capital expenditure for transmission, distribution and corporate separately in the following paragraphs.

Transmission Forecast Capital Expenditure

808. Western Power’s initial proposed forecast transmission capital expenditure for the third access arrangement period is provided in Table 72 below broken down into regulatory categories.

Table 72 Western Power's initial proposed forecast transmission network capital expenditure (real $ million at 30 June 2012)[202]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion	215.6	128.3	204.1	338.5	226.2	1,112.7
Customer Driven	31.4	31.0	30.7	30.4	31.6	155.0
Asset Replacement	30.3	32.7	32.8	32.7	34.0	162.5
Regulatory Compliance	14.0	16.7	23.3	28.9	29.4	112.3
Reliability	0.0	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	14.2	11.9	12.9	18.3	18.0	75.3
Total Capital Expenditure excluding real input cost escalation	**305.5**	**220.6**	**303.7**	**448.7**	**339.2**	**1,617.7**

809. Capacity expansion and customer driven investment is growth related. Capacity expansion relates to investment required to meet load growth and maintain security of the network. Customer driven investment is to meet the requirements of specific individual customers. The remaining investment categories are not related to growth. They reflect the need for asset replacement, complying with regulations, for the direct purpose of improving reliability (although there may be indirect benefits to reliability from other investment) and for communications equipment.

810. In the Draft Decision the Authority did not accept Western Power's proposal. The Authority's assessment of forecast transmission network capital expenditure for the third access arrangement period is summarised in Table 73 below.

202 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes. The capital expenditure line provided in Table 66 included real input cost escalation. The Authority has assessed real input cost escalation separately to better assess Western Power's forecast capital expenditure.

Table 73 Draft Decision transmission network capital expenditure (real $ million at 30 June 2012)[203]

	2012/13	2013/14	2014/15	2015/16	2016/17	5 years
Capacity Expansion	176.6	250.5	99.2	111.0	151.0	788.3
Customer Driven	20.1	19.9	19.7	19.5	19.7	98.9
Asset Replacement	30.3	32.7	32.8	32.7	34.0	162.5
Regulatory Compliance	14.0	16.7	23.3	28.9	29.4	112.3
Reliability	0.0	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	11.4	8.7	10.1	15.2	14.5	59.9
Draft Decision Total	**252.4**	**328.5**	**185.1**	**207.3**	**248.6**	**1,221.9**
Western Power's Initial Proposal	305.6	220.6	303.7	448.7	339.2	1,617.7

811. In response to the Authority's Draft Decision, Western Power amended its forecast transmission capital expenditure for the third access arrangement period as shown in Table 74 below.

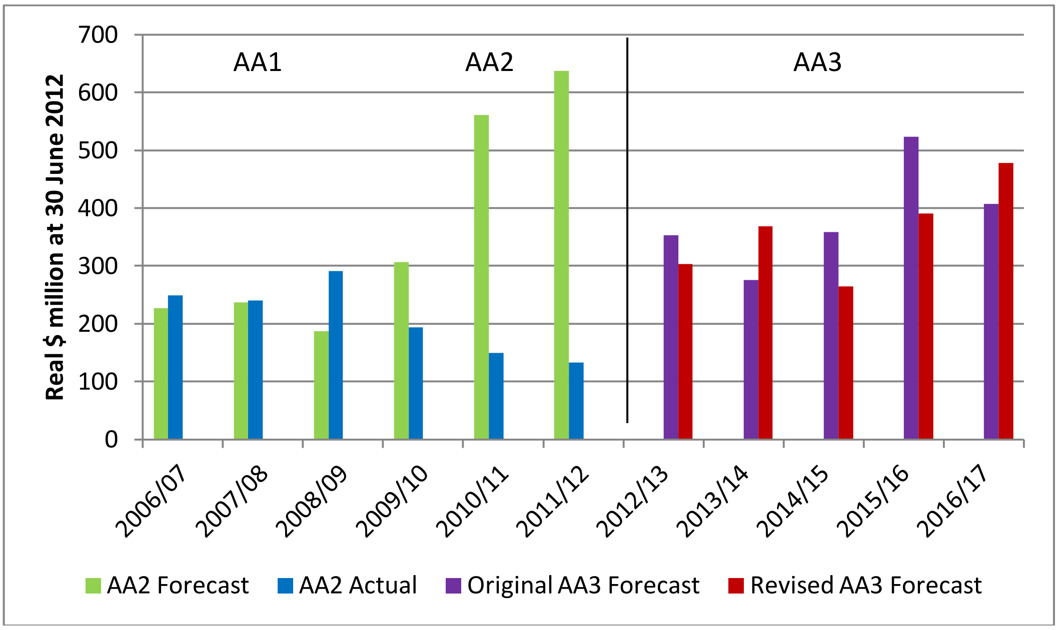
203 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

Table 74 Western Power's revised proposed forecast transmission network capital expenditure (real $ million at 30 June 2012)[204]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Draft Decision
Capacity Expansion	185.8	247.3	140.7	243.0	317.6	1,134.4	788.3
Customer Driven	13.8	24.5	24.5	24.4	24.3	111.5	98.9
Asset Replacement	29.6	31.0	31.1	31.0	31.8	154.6	162.5
Regulatory Compliance	18.1	19.5	24.3	29.5	29.6	121.0	112.3
Reliability	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	13.9	11.5	12.6	17.8	17.3	73.0	59.9
Total Capital Expenditure excluding real input cost escalation	**261.2**	**333.8**	**233.2**	**345.7**	**420.6**	**1,594.6**	**1,221.9**

812. Figure 8 below shows Western Power's proposed and revised proposed forecast transmission capital expenditure, net of capital contributions and inclusive of corporate expenditure and real input cost escalation, for the third access arrangement period.

Figure 8 Transmission capital expenditure (real $ million at 30 June 2012)



204 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

813. Western Power has forecast transmission network capital investment to increase significantly during the third access arrangement period compared with earlier access arrangement periods. Western Power's revised forecast for the third access arrangement period is slightly lower than its initial forecast.

814. Apart from transmission reliability capital expenditure initiatives, which were only a very minor expenditure item during the second access arrangement period, Western Power has forecast all other categories of transmission capital expenditure to significantly increase during the third access arrangement period. In particular, capacity expansion, which represents over 70 per cent of net transmission network capital expenditure (excluding corporate expenditure) is the significant driver of Western Power's forecast transmission capital expenditure.

815. The Authority has considered each of the investment categories below.

Capacity Expansion

816. Western Power's initial proposed forecast capacity expansion capital expenditure of $1,112.7 million during the third access arrangement period was 134 per cent higher on an average annual basis than in the current access arrangement period. This increase was driven by expenditure for the Mid West Energy Project (MWEP) and a significant increase in "thermal" augmentation of the shared transmission network. GBA, the Authority's technical advisor, generally concluded that most of Western Power's proposed forecast capacity expansion expenditure during the third access arrangement period was reasonable, although with some significant exceptions discussed below.

817. As a result, in its Draft Decision, the Authority required that Western Power's transmission capital expenditure be adjusted according to the amended forecast for capacity expansion in Table 75 below.

Table 75 Authority's Draft Decision transmission capacity expansion capital expenditure (real $ million at 30 June 2012)[205]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal	215.6	128.3	204.1	338.5	226.2	1,112.7
Western Power's initial proposal after errata amendment	199.7	296.8	203.5	338.5	226.2	1,264.7
Adjustment to remove originally proposed MWEP expenditure	(175.8)	(28.4)	(3.7)	(5.9)	(27.6)	(241.4)
Adjustment to add pre-approved MWEP NFIT amount	163.2	197.0	1.4	-	-	361.6
Adjustment to remove new CBD substation	-	(3.9)	(26.8)	(59.9)	(4.8)	(95.4)
Adjustment to remove new CBD substation supply cable	-	-	(5.1)	(22.2)	(2.4)	(29.7)
Adjustment to remove Eneabba Terminal	-	-	(2.9)	(12.7)	(1.4)	(17.0)
Adjustment to remove environmental and planning	(17.0)	(11.5)	(9.9)	(8.5)	(9.4)	(56.3)
Adjustment for reduced load growth	(9.4)	(31.0)	(57.9)	(118.3)	(29.6)	(246.2)
Draft Decision	**176.6**	**250.5**	**99.2**	**111.0**	**151.0**	**788.3**

818. In response to the Draft Decision, Western Power made some amendments to its forecast transmission capacity expansion capital expenditure resulting in a small decrease to total forecast expenditure.

205 Real cost escalation has been removed for comparison purposes, except for the adjustment to remove the originally proposed MWEP (stage 1) expenditure which includes real cost escalation in 2012/13, 2013/14 and 2014/15 with the pre-approved MWEP NFIT amount.

Table 76 Western Power's revised proposed transmission capacity expansion capital expenditure (real $ million at 30 June 2012)[206]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's Initial Proposal	215.6	128.3	204.1	338.5	226.2	1,112.7
Western Power's initial proposal after errata amendment	199.7	296.8	203.5	338.5	226.2	1,264.7
Draft Decision	176.6	250.5	99.2	111.0	151.0	788.3
Western Power's Revised Proposal	**185.8**	**247.3**	**140.7**	**243.0**	**317.6**	**1,134.4**

819. It is noted that Western Power cannot commit to a major capacity expansion before the Authority determines that it will meet the 'regulatory test' as set out in Chapter 9 of the Access Code. Western Power indicated that nine of the projects included in its expenditure in its proposed revisions for the third access arrangement period will require regulatory test approval. The regulatory test requires Western Power to demonstrate that a proposed major augmentation maximises the net benefit after considering alternative options and that adequate public consultation has been conducted.

820. If Western Power chooses to proceed with a project that the Authority has removed from Western Power's forecast transmission capital expenditure (or to proceed with a new capacity expansion project that has not been included in Western Power's proposed revised access arrangement) then, providing the expenditure is considered by the Authority to be efficient at the next access arrangement review and it meets other elements of the new facilities investment test, the expenditure will be added to the opening capital base for the fourth access arrangement period. Furthermore, Western Power will be eligible to receive a return on this investment from the date it is incurred, as calculated by the Investment Adjustment Mechanism.

821. Western Power is also able to obtain pre-approval for the amount of expenditure that can be rolled into the capital base by lodging a new facilities investment test application at any time under section 6.71 of the Access Code.

822. The Authority's specific amendments to Western Power's proposed forecast capacity expansion capital expenditure, taking account of responses to the Draft Decision, are discussed below.

Mid West Energy Project

823. Western Power issued an *errata* to its proposed revisions to the access arrangement shortly after submitting them to the Authority, as a significant amount of expenditure relating to the Mid West Energy Project (**MWEP**) had been omitted from its capital expenditure forecasts in error. Subsequent to the errata, the Authority released its

206 Real cost escalation has been removed for comparison purposes, except for the adjustment to remove the originally proposed MWEP (stage 1) expenditure which includes real cost escalation in 2012/13, 2013/14 and 2014/15 with the pre-approved MWEP NFIT amount.

final decision on Western Power's pre-approval NFIT application for the MWEP (southern section) in January 2012. The Authority's final decision was to pre-approve the inclusion of $377.8 million (real dollars at 30 June 2010) for the MWEP (southern section). Prior to the Draft Decision, Western Power provided a breakdown of the expenditure and $340.5 million (real dollars at 30 June 2010) is forecast to be spent during the third access arrangement period. The remaining expenditure from the pre-approval has already been spent by Western Power prior to the third access arrangement period. The Authority has only allowed the proposed forecast expenditure that it has determined meets the NFIT.

824. Western Power also proposed to include around $35.4 million for stage 2 of the MWEP. However, as there is considerable uncertainty regarding when this project will proceed, the Authority was not satisfied that this expenditure would satisfy the NFIT and removed it from forecast capital expenditure in the Draft Decision.

825. In response to the Draft Decision, Western Power's amended access arrangement information notes that this expenditure for 'stage 2 of the MWEP' was actually for the southern section rather than the northern section. In Western Power's errata this distinction was not drawn and the Authority interpreted the expenditure as relating to the northern section and therefore, due to the considerable uncertainty regarding this project, removed the expenditure from forecast capital expenditure.

826. Western Power considers that the $35.4 million removed by the Authority in its Draft Decision should be reinstated as this expenditure is required to allow the NFIT pre-approved MWEP (southern section) to be upgraded so that both sides of the double circuit operate at 330 kV. Western Power considers that this expenditure is necessary to accommodate forecast generation developments and new block loads in the region. Western Power notes that it has received increased level of customer enquiries since the Authority's final decision on Western Power's pre-approval NFIT application for the MWEP (southern section).

827. GBA has confirmed that the $35.4 million which Western Power has reinstated in its revised proposed access arrangement is to allow a second circuit of the MWEP to operate at 330 kV and that this was not included in its pre-approval NFIT application of the MWEP (southern section). However, GBA is unaware of any new block loads that would require this augmentation to be commissioned before the end of the third access arrangement period. GBA has noted that this augmentation would be required to allow the connection of Western Power's proposed 330 kV Eneabba terminal station (this project is discussed below). GBA has suggested, as it did prior to the draft decision for the Eneabba terminal station, that Western Power's efficient expenditure for the second circuit of the MWEP to operate at 330 kV could be recovered through the Investment Adjustment Mechanism should wind farm development proceed to the stage where this investment is required for the third access arrangement period.

828. The Authority notes that while Western Power has stated it has had an increased level of customer enquiries for the MWEP, GBA is unaware of any new block loads that would require this augmentation to be commissioned before the end of the third access arrangement period. As a result, the Authority considers that current customers should not have to pay in advance for this uncertain investment and that Western Power may apply the investment adjustment mechanism to this investment providing it met NFIT requirements. The investment adjustment mechanism ensures Western Power is no worse off for not having this investment included in its forecast expenditure now, should this investment meet the NFIT requirements at a later time.

829. The Authority notes that this augmentation is required for Western Power's Eneabba terminal station augmentation. In its Draft Decision, the Authority considered that the Eneabba terminal station augmentation was uncertain and that current customers should not have to pay in advance and that Western Power may apply the investment adjustment mechanism to this investment providing it met NFIT requirements. As noted below in paragraph 841, the Authority is still of the view that the need for the Eneabba terminal station remains uncertain. Consequently, the Authority has not altered its view in relation to the adjustments required for the MWEP as set out in the Draft Decision.

CBD Substation and Supply Cable

830. Western Power's proposed capacity expansion capital expenditure forecasts for the third access arrangement period included a $95.4 million project to construct a new CBD substation. GBA assessed this expenditure prior to the Draft Decision and was not satisfied that the construction of a new substation in the CBD during the third access arrangement period was consistent with the least cost approach to addressing emerging supply issues within the CBD.[207] GBA also noted that even if a new substation was needed based on information from Western Power, there is little risk in deferring the project to the fourth access arrangement period, and that this additional time would provide Western Power more time to undertake a strategic planning study. Consistent with its recommended deferral of the new CBD substation, the associated supply cable at a forecast cost of $29.7 million should also be deferred.

831. In the Draft Decision, the Authority was concerned that Western Power had not given due consideration to identifying the least cost approach to addressing a network supply issue. Considering that GBA had identified lack of identification of as a governance issue in the current access arrangement period, the Authority was concerned that Western Power's governance needs to improve significantly to ensure that all options are considered to address supply issues and that the least cost option is identified. As a result, the Authority considered that forecast expenditure for a new CBD substation and associated supply cable should be removed from Western Power's forecast transmission capital expenditure.

832. In response to the Draft Decision, Western Power's amended access arrangement information incorporated a reduced expenditure forecast for the CBD area of $110.3 million (CBD substation and supply cable) as indicated in Table 77.

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[207] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 77.

Table 77 Western Power's revised proposed transmission network capacity expansion for CBD substation and supply cable (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Cook St to Western Terminal 132 kV line	-	-	0.1	0.3	2.0	2.4
East Perth to new Bennett St Substation – Two 132 kV cable circuits	-	-	0.5	0.7	4.9	6.1
New Bennett St Substation	0.4	1.0	10.6	10.3	35.5	57.8
Hay St to Milligan St 132 kV cable	0.1	0.4	1.5	5.1	0.6	7.8
Complete Joel Terrace 132 kV conversion	0.7	4.4	9.9	0.9	-	15.8
James St – Single transformer	0.1	0.3	0.9	5.9	13.2	20.4
Western Power's revised proposed CBD substation and supply cable expenditure	**1.3**	**6.1**	**23.3**	**23.2**	**56.3**	**110.3**
Western Power's initial proposal	0.0	3.9	31.9	82.1	7.2	125.1

833. GBA has reviewed the revised proposal for the CBD substation and notes that Western Power's revised proposal is very different in nature from its initial proposal. GBA notes that Western Power's amended expenditure forecast for the CBD area now forms part of a longer term strategy to address emerging issues with the CBD and in particular the ageing 66 kV infrastructure and the operating and capacity problems that would eventually arise if these assets were to be replaced on a like for like basis. GBA notes that these issues were not raised in Western Power's access arrangement information (September 2011). GBA considers that the different CBD development plan now proposed by Western Power confirms GBA's view in its Technical Report prior to the Draft Decision that the original plan was sub-optimal and not well developed.

834. GBA considers that Western Power's amended CBD development plan is more about asset replacement than about capacity expansion and, with the exception of the Cook St – Western Terminal overhead line, supports the plan. GBA notes that the Cook St – Western Terminal overhead line project typifies many of its concerns with Western Power's capacity expansion capital expenditure planning and, particularly its consideration of risk.

835. The Authority is concerned that Western Power's original plan was inefficient and not thoroughly developed. The Authority highlighted its concerns regarding Western

Power's expenditure planning processes in its Draft Decision. While Western Power appears to have put more thought into the development of its revised proposal for the CBD substation, the Authority considers that the late substitution of the amended plan suggests that Western Power has some way to go before its internal planning processes are at a sufficient standard. Had the Authority not questioned and removed this expenditure for its Draft Decision, Western Power may have proceeded with an inefficient investment.

836. GBA notes that Western Power has included the Cook St – Western Terminal overhead line project because Western Power's consultant (SKM) found that by the end of the third access arrangement period, the Western terminal station may not meet the N-1-1 security criterion required by clause 2.5.2.3 of the Technical Rules. This clause requires that substations designed to the N-1-1 criterion must be able to continue to supply up to 80 per cent of its peak demand if an unplanned outage of a transmission element occurs at the same time as a planned maintenance element of another element. GBA considers that the business risk that this project is trying to manage is substantially lower than other risks of non-supply in the Western terminal load area which the network is not designed to mitigate and that are considered acceptable and in accordance with good industry practice.

837. GBA also observed that:

- the smallest incoming circuit to Western Terminal has a capacity of 210 MVA which is 35 per cent higher than the 2013 peak demand forecast and that there is no suggestion that the Western Terminal peak demand will increase by 35 per cent within 5 years;
- Western Power could defer the need for the project by scheduling maintenance for a period when the expected actual demand was below 80 per cent. GBA noted that Western Power provided data which showed that there is a nine month window when the load does not exceed 75 per cent of the annual peak demand; and
- should load shedding be required, the impact on customers could be managed by load rationing.

838. The Authority notes that Western Power has revised its expenditure forecasts for the CBD substation and supply cable based on a different plan which appears to form part of a longer term strategy. However, the Authority shares GBA's concern with regard to the Cook St – Western Terminal overhead line and considers that this expenditure is not required in the medium term. Western Power's proposed expenditure for the Cook St – Western Terminal line which GBA notes is a substantially lower risk than other risks of non-supply which are considered acceptable. Western Power should be undertaking a thorough risk assessment on all of its proposed investments. The Authority notes that Western Power can apply to the Authority for a Technical Rules exemption for this project. The Authority requires the adjustment to Western Power's transmission capacity expansion for the CBD substation and supply cable as indicated in Table 82.

Table 78 Final Decision transmission network capacity expansion for CBD substation and supply cable (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's revised proposal	1.3	6.1	23.3	23.2	56.3	110.3
Adjustment to remove Cook St to Western Terminal 132 kV line	-	-	(0.1)	(0.3)	(2.0)	(2.4)
Final Decision	**1.3**	**6.1**	**23.0**	**22.9**	**54.3**	**107.8**

Numbers may not add due to rounding.

Eneabba Terminal Station

839. Western Power forecast to spend $17 million on the construction of a terminal station at Eneabba during the third access arrangement period. GBA reviewed this expenditure and noted that the Eneabba terminal station is required to support potential new wind generation projects around Eneabba. However, GBA considered that the timing around this potential new generation is speculative and that the economics of wind farm development are still uncertain. GBA considered that, should there be a need for the Eneabba terminal station during the third access arrangement period, then the investment adjustment mechanism could apply to allow recovery of costs during the fourth access arrangement period.[208] In its Draft Decision, the Authority agreed with GBA's reasoning that current customers should not have to pay in advance for this uncertain investment and that Western Power may apply the investment adjustment mechanism to this investment providing it met NFIT requirements. On this basis, the Authority considers that the costs of the Eneabba terminal should not be included in Western Power's forecast transmission capital expenditure.

840. In its amended access arrangement information, Western Power removed this expenditure from its forecast transmission capacity expansion expenditure as it believes that the costs for the terminal are adequately provided for in forecast transmission customer-driven expenditure.

841. As this expenditure has been removed from this expenditure category and there has not been an increase in other categories of expenditure for the Eneabba terminal, it satisfies the Authority's requirements. The Authority remains of the view that the need for the Eneabba terminal station during the third access arrangement period is still uncertain.

Environmental and Planning

842. Western Power forecast expenditure of around $56.3 million on environmental and planning costs during the third access arrangement period. GBA reviewed this

208 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 78-79.

expenditure and considered that this expenditure would not meet NFIT requirements. GBA noted that, prior to 2011/12, no expenditure was recorded in this category as all expenditure on environmental and planning issues were directly attributed to individual capital expenditure projects.[209] In its Draft Decision, the Authority accepted GBA's advice and agreed that the expenditure for environmental and planning, which totals $56.3 million, does not meet the requirements of the new facilities investment test.

843. In its amended access arrangement information, Western Power notes it has amended its forecast environmental and planning costs to remove those elements of planning costs that are not directly attributable to projects from the capital expenditure forecast. Western Power has advised that $0.8 million per annum of the initial forecast relates to early strategic planning costs incurred prior to Gate 1 in Western Power's works program model and are not directly attributable to individual projects. Western Power has advised that the remainder of the forecast (as set out in Table 79 below) relates to costs incurred following Gate 1 and are directly attributable to individual projects.

Table 79 Western Power's revised environmental and planning costs directly attributable to capital projects (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's revised proposal	16.2	10.7	9.1	7.7	8.6	52.3

844. Taking account of this further information from Western Power, the Authority agrees that the early strategic planning costs should not have been included in capital expenditure as they are operating costs. The Authority has adjusted base operating expenditure for the third access arrangement period by $0.8 million per annum to allow for early strategic planning costs which were not included in the 2010/11 base operating expenditure reviewed by the Authority's technical consultant.

845. In relation to the amount that should be included in capital expenditure, the Authority notes that Western Power's forecast was based on a higher amount of transmission expenditure than was determined by the Authority in the Draft Decision. The Authority considers the amount forecast for environmental and planning forecasts needs to be adjusted to reflect the lower transmission expenditure approved by the Authority. The Authority has determined a revised forecast using percentages derived from Western Power's initial forecast.[210] The revised forecast is set out in Table 80 below.

[209] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 79-80.

[210] The Authority calculated the ratio of Western Power's proposed environmental and planning costs to Western Power's proposed transmission capacity expansion capital expenditure and applied this ratio to the forecast transmission capacity expansion capital expenditure determined by the Authority.

Table 80 Final Decision environmental and planning costs directly attributable to capital projects (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Final Decision	15.9	9.6	5.8	3.1	8.2	42.6

846. The Authority's Final Decision in relation to forecast expenditure for transmission capacity expansion is based on the numbers in Table 80 above.

Reduced Load Growth

847. In its proposed revisions to the access arrangement, Western Power forecast its capacity expansion capital expenditure on the basis of the 10 per cent probability of exceedence (**POE**) central load forecast in its 2010 Annual Planning Report. Western Power's 2010 Annual Planning Report indicated that peak demand in 2018 would reach 5,225 MW. Subsequent to Western Power's proposed access arrangement revisions submission, Western Power's 2011 Annual Planning Report became available. This report forecast that peak demand would only reach 4,738 MW. Western Power's 2011 Annual Planning Report states that the peak demand is currently 4,005 MW, set on 25 February 2011. GBA noted that this implied that, whilst Western Power's growth driven capital expenditure was intended to support growth in demand of 1,220 MW in its access arrangement submission, the 2011 Annual Planning Report suggested that only 733 MW of demand growth was required. GBA noted that this suggested that up to 40 per cent of Western Power's growth driven capital expenditure could be deferred to the fourth access arrangement.

848. As a result, GBA recommended a reduction to the transmission supply and transmission voltage capital expenditure by 40 per cent. GBA also identified load driven projects (the 132 kV Mungarra-Geraldton and Kojonup-Albany lines) which could be deferred and that the proposed expenditure on the Mungarra-Geraldton line was not consistent with the proposed MWEP (northern section).[211]

849. In its Draft Decision, the Authority agreed with GBA's assessment of the reduced need for growth driven capital expenditure based on Western Power's latest available estimates of peak demand growth and with the deferral of the 132 kV Mungarra-Geraldton and Kojonup-Albany lines. The Authority required an adjustment to Western Power's capacity expansion expenditure as shown in Table 81.

211 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 80-82.

Table 81 Draft Decision adjustment for reduced load growth (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Reduction in transmission supply capital expenditure	(8.2)	(28.8)	(30.4)	(19.8)	(19.7)	(106.9)
Reduction in transmission voltage capital expenditure	(1.1)	(2.2)	(8.2)	(14.0)	(0.9)	(26.4)
Deferral of the Mungarra-Geraldton line	-	-	(6.8)	(29.9)	(3.2)	(39.9)
Deferral of the Kojonup-Albany line	-	-	(12.5)	(54.6)	(5.9)	(73.0)
Total adjustment	**(9.4)**	**(31.0)**	**(57.9)**	**(118.3)**	**(29.6)**	**(246.2)**

850. In response to the Draft Decision, Western Power argues that it is the change in demand using the latest 2011 Annual Planning Report demand forecasts that determines the required capacity expansion capital expenditure. The 2011 demand forecast incorporates a demand increase across the five years of the third access arrangement period of 476 MW, which is 61 MW (or 12 per cent) less than the 537 MW of growth forecast in the 2010 forecast.

851. GBA contests this view and considers that Western Power should have developed its network for the start of the third access arrangement period on the 2010 Annual Planning Report demand forecast and only use the 2011 Annual Planning Report demand forecast to inform its regulatory proposal for capital expenditure required during the third access arrangement period. GBA notes that Western Power's approach does not take into account the reduction in forecast demand for the 2012 year (i.e. the starting point for the third access arrangement period) between the 2010 Annual Planning Report and the 2011 Annual Planning Report demand forecasts.

852. However, Western Power has argued that it requires the majority of its proposed investment because, among other reasons, there was a lack of transmission investment during the current access arrangement period, it has existing capacity shortages, and it has an existing level of non-compliance with aspects of the Technical Rules.

853. GBA considers that Western Power, as noted in its 2010 Annual Planning Report, would have been developing its network to meet the higher demand forecast for 2012 as this was the best information it had available at the time. GBA is of the view that notwithstanding the deferral of some transmission projects there is no indication that Western Power failed to develop its network for the higher 2012 starting demand. This suggests to GBA that there should be some spare capacity in the network due to the now lower starting point demand in the 2011 Annual Planning Report, which should be utilised before additional augmentation is needed.

854. GBA notes that its calculated reduction in demand of 40 per cent, which was the basis for its recommendation that 40 per cent of Western Power's growth driven capital expenditure could be deferred to the fourth access arrangement period, underestimates the reduction in demand that could have been applied to Western Power's growth driven capital expenditure. This is because it assessed demand growth over a seven year period (2011-2018) and applied that to the five year access arrangement period expenditure. GBA notes that had it adopted a five year period of assessing demand growth from 2013 to 2018, then the suggested reduction from using the 2011 Annual Planning Report demand forecast would have been 70 per cent.

855. GBA remains of the view that its recommended reductions in capacity expansion capital expenditure to provide for the reduced demand forecast in Western Power's 2011 Annual Planning Report is reasonable. GBA does not accept Western Power's view that it is the change in demand using only the 2011 Annual Planning Report demand forecast rather Western Power should have developed its network to start the third access arrangement period using the demand forecast from the 2010 Annual Planning Report, which was higher than the now proposed peak demand for 2012. GBA says that, while its recommended reductions were at a high level and based on broad assumptions, the recommended reductions were not excessive and provided Western Power with scope to address the issue of customer risk.

856. However, GBA has revised its recommended reduction in transmission supply capital expenditure to now exclude the Cook Street transformer before applying a 40 per cent reduction for reduced load growth. GBA had excluded the forecast CBD substation expenditure but not the Cook Street transformer from its recommended reduction prior to the Draft Decision. GBA considers that there is a good case to treat the transmission supply issues within the CBD separately from the rest of the network. As a result, GBA has recommended that the Authority reinstate $5.3 million into Western Power's proposed forecast transmission network capacity expansion expenditure.

857. GBA believes that the remaining provision for transmission supply capital expenditure will allow Western Power to install a reasonable number of new substations and transformers taking into account the following matters:

- Western Power bases its timing for additional zone transformer capacity using a load forecast based on 10 per cent probability of exceedence. There is a 90 per cent probability that the actual load will be lower than forecast in any particular year;
- There will only be an interruption if there is a transformer failure during peak load periods. Western Power's actual demand only exceeds 90 per cent of its peak demand for less than 1 per cent of the time during the year. In a worst case scenario it may be possible to avoid extended supply interruptions by transferring load to neighbouring substations or rotating customer interruptions during peak demand; and
- The Investment Adjustment Mechanism enables Western Power to eventually recover all expenditure (providing it meets the NFIT requirements) even if it is greater than provided for in the revenue cap. Hence if the Authority has underestimated the necessary expenditure for capacity expansion, the risk to Western Power is low.

858. GBA also notes that Western Power's forecast cost for the construction and expansion of zone substations was, on average, significantly higher than its historic costs of similar projects and that Western Power's explanation for this was

unconvincing. As a result, GBA considers that Western Power will be able to complete a greater volume of work on the basis of a lower actual cost.

859. In the Draft Decision, the Authority considered that the Kojonup-Albany 132 kV line and the Mungarra-Geraldton 132 kV line should be deferred beyond the third access arrangement period. Western Power has responded by deferring the Kojonup-Albany line, slightly reducing capital expenditure by $2.6 million during the third access arrangement period and arguing that the Mungarra-Geraldton line should remain as originally forecast.

860. GBA notes that Western Power's proposed Kojonup-Albany line appears to be predicated on the assumption that network augmentation is the only option available to Western Power. GBA disputes that assumption. GBA also highlights that Western Power is currently undertaking a tendering process for network control services which will secure the supply to Albany and that it is not clear if Western Power has updated its analysis of whether augmentation is a lower cost option compared to network control services as a result of the reduced demand forecast in Western Power's 2011 Annual Planning Report and the impact of the Albany wind farm commissioned in late 2011. Given the information available to GBA, it is satisfied that the supply to Albany is secure and that deferral of this project to the fourth access arrangement period presents little technical or economic risk to Western Power.

861. GBA has noted that peak demand in the North Country load area (for which the Mungarra – Geraldton line would help service) was reduced by 17 per cent in Western Power's 2011 Annual Planning Report. GBA noted that, while this significant reduction may represent the removal of one or more block loads and covers a geographic area much larger than Geraldton, it does suggest a potential to defer any network augmentation required only to address incremental load growth around Geraldton. GBA considers that the likelihood that any grid reinforcement will cost significantly more than required to address just incremental load growth strengthens the economic argument to defer the augmentation until the longer term requirement is known with more certainty and in the interim place more reliance on non-network alternatives such as network control services.

862. Taking into account the comments in GBA's report (summarised above) and Western Power's submissions, the Authority remains of the view that GBA's assessment of the reduced need for growth driven capital expenditure based on Western Power's 2011 Annual Planning Report demand forecasts is reasonable. The Authority considers that GBA's proposed adjustment to its recommendation to exclude the Cook Street transformer before applying a 40 per cent reduction for reduced load growth is reasonable. As a result, the Authority has applied that adjustment as indicated in Table 82.

863. The Authority also remains of the view that the Kojonup-Albany and Mungarra-Geraldton lines can be deferred to the fourth access arrangement period and has decided not to include Western Power's revised proposed expenditure for these assets. This does not mean that if the need for these lines changes that Western Power can't build these assets in the third access arrangement period. As noted elsewhere in discussion on transmission capacity expansion expenditure (for example paragraph 829), if Western Power believes it must proceed with these augmentations and can demonstrate that these projects satisfy the NFIT requirements at the next regulatory review, Western Power will be compensated through the investment adjustment mechanism.

864. The Authority's recalculation of forecast transmission network capacity expansion is set out in Table 82 below.

Table 82 Final Decision adjustment for reduced load growth (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	(8.2)	(28.8)	(30.4)	(19.8)	(19.7)	(106.9)
GBA revised recommended reduction in transmission supply capital expenditure	(7.3)	(24.7)	(29.9)	(19.8)	(19.7)	(101.5)
Final Decision	**0.9**	**4.0**	**0.4**	**0.0**	**0.0**	**5.3**

Summary

865. Taking account of the matters discussed above, the Authority has recalculated the total forecast for capacity expansion as set out in Table 83 below.

Table 83 Final Decision transmission capacity expansion capital expenditure (real $ million at 30 June 2012)212

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	**176.6**	**250.5**	**99.2**	**111.0**	**151.0**	**788.3**
Adjustment to reinstate revised proposed CBD substations and supply cable expenditure	1.3	6.1	23.3	22.9	54.3	107.8
Adjustment to reduction in load growth	0.9	4.0	0.4	0.0	0.0	5.3
Adjustment to include environmental and planning costs	15.9	9.6	5.8	3.1	8.2	42.6
Final Decision	**194.7**	**270.2**	**128.7**	**137.0**	**213.5**	**944.1**

Transmission Customer Driven Capital Expenditure

866. Western Power's proposed forecast net customer-driven capital expenditure (excludes capital contributions) of $155 million during the third access arrangement

212 Real cost escalation has been removed for comparison purposes.

period was 292 per cent higher on an average annual basis than the current access arrangement period. The forecast increase was driven by a 38 per cent increase in forecast gross customer-driven capital expenditure (inclusive of capital contributions) and an 8 per cent reduction in forecast capital contributions on an average annual basis as compares with the current access arrangement period. GBA advised the Authority that the forecast capital expenditure was not entirely reasonable and recommended amendments to the forecasts.

867. GBA noted that Western Power stated that its gross customer-driven capital expenditure forecast was based on an historic level adjusted for identifiable drivers. However, GBA noted that its forecast appears high given that the 38 per cent increase is much higher than the expected network growth rate. GBA considered that the forecast average gross customer-driven capital expenditure should be adjusted so it exceeds the average in the current access arrangement period by only 10 per cent.

868. GBA noted that during the first and current access arrangement periods, capital contributions offset on average 65 per cent of gross customer-driven capital expenditure. However, Western Power proposed that this offset be reduced to 56 per cent of gross customer-driven capital expenditure for the third access arrangement period. GBA noted that Western Power did not provide any rationale for this reduction and considered that the forecast capital contributions should be increased to the historic levels.[213]

869. In its Draft Decision, the Authority agreed with GBA's assessment that the net customer driven capital expenditure should be adjusted to reflect the forecasts for gross customer-driven expenditure and capital contributions recommended by GBA, as indicated in Table 84. As noted in paragraph 820, the investment adjustment mechanism would apply to this category of expenditure and as a result, any additional expenditure that Western Power may need to spend (and that meets the NFIT) can be compensated for in the fourth access arrangement period.

Table 84 Draft Decision forecast transmission customer driven capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's Initial Proposal						
Expenditure	72.1	71.2	70.5	69.9	70.7	354.4
Capital contributions	(40.7)	(40.2)	(39.8)	(39.5)	(39.1)	(199.3)
Net expenditure	31.4	31.0	30.7	30.4	31.6	155.1
Draft Decision						
Expenditure	57.5	56.8	56.2	55.8	56.4	282.7
Capital contributions	(37.4)	(36.9)	(36.5)	(36.2)	(36.7)	(183.7)
Net expenditure	20.1	19.9	19.7	19.5	19.7	98.9

870. In response to the Draft Decision, Western Power's revised proposed forecast of net customer-driven capital expenditure has been reduced to around $111.5 million over the third access arrangement period. However, this is around $13 million higher over the period compared to the Authority's Draft Decision. Western Power accepted the methodology of limiting gross customer-driven expenditure to 10 per cent of the

213 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 84.

average expenditure in the current access arrangement period. However, Western Power updated its forecast based on the most recent 2011/12 forecast and used project specific forecasts for 2012/13. Western Power agreed that the Authority's method of determining the contribution rate by using an average of historical data is reasonable. However, Western Power noted that there are two distinct activities within customer-driven capital expenditure and that transmission line relocations activity is 100 per cent funded by contributions. As a result, it has proposed to use a 100 per cent contribution rate for transmission line relocations and a revised contribution rate for other customer driven activities of around 53 per cent (based on an historic average of the first and current access arrangement periods).

871. The Authority notes that in total Western Power's assumed contributions rate is around 58 per cent compared to GBA's recommended 65 per cent. GBA considers that while Western Power has updated its forecasts for the latest 2011/12 forecast, it is clear from both its' analysis and Western Power's analysis that the contribution rate during the current access arrangement period was significantly higher than the first access arrangement period and that an assumption of 65 per cent is not unreasonable. GBA considers that there is no reason to further adjust the net customer-driven transmission capital expenditure.

872. The Authority considers that it is reasonable to use Western Power's latest forecast for gross customer-driven capital expenditure which uses a specific forecast for 2012/13 and limits the increase over the remaining years to 10 per cent of the average expenditure in the current access arrangement period. However, the Authority considers that it is reasonable to remain with a 65 per cent contribution rate (as recommended by GBA) especially as Western Power's own analysis indicates that the contributions rate increased significantly during the current access arrangement period and Western Power's analysis indicates that the contribution rate was around 72 per cent during the current access arrangement period.

873. As a result, the Authority has determined forecast net customer driven capital expenditure to be as set out in Table 85 below.

Table 85 Final Decision forecast transmission customer driven capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's revised proposal						
Customer driven expenditure	34.1	57.9	57.9	57.9	57.9	265.7
Capital contributions	(20.3)	(33.4)	(33.4)	(33.4)	(33.4)	(153.9)
Net customer driven expenditure	13.8	24.5	24.5	24.4	24.3	111.5
Final Decision						
Customer driven expenditure	34.1	57.9	57.9	57.9	57.9	265.7
Capital contributions	(22.2)	(37.6)	(37.6)	(37.6)	(37.6)	(172.6)
Net customer driven expenditure	11.9	20.3	20.3	20.3	20.3	93.1

Transmission Asset Replacement

874. Western Power forecast asset replacement expenditure of $162.5 million over the third access arrangement period. GBA assessed this expenditure forecast and considered the amount to be reasonable. GBA noted that Western Power's asset replacement capital expenditure was forecast to increase by 55 per cent on average in real terms from the current access arrangement period. GBA noted that this increase is driven almost entirely by a substantial increase in the rate of replacement of indoor circuit breakers. GBA reviewed the forecast replacement of indoor circuit breakers and considered it reasonable on safety-related grounds. The Authority agreed with GBA's view and concluded that the expenditure proposed by Western Power was reasonable.

875. In response to the Draft Decision, Western Power states it has increased its asset replacement expenditure by $2.3 million to cover the additional costs of purchasing SF_6 gas as a result of the Australian Government's Clean Energy Future legislation.

876. GBA has not assessed the reasonableness of the amount forecast by Western Power relating to the additional costs of purchasing SF_6 gas as the amount is not a material component of the total capital expenditure forecast.

877. The Authority considers that Western Power's forecast of additional costs in relation to compliance with the Australian Government's Clean Energy Future legislation, is reasonable and, in its Final Decision, has amended the Draft Decision forecast to incorporate the additional costs as set out in Table 86 below.

Table 86 Final Decision asset replacement capital expenditure (real $ million at 30 June 2012)[214]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal	30.3	32.7	32.8	32.7	34.0	162.5
Draft Decision	30.3	32.7	32.8	32.7	34.0	162.5
Additional costs for purchasing SF6 Gas to comply with Clean Energy Future legislation	0.4	0.4	0.4	0.5	0.5	2.3
Final Decision	**30.7**	**33.1**	**33.2**	**33.2**	**34.5**	**164.7**

Transmission Regulatory Compliance Expenditure

878. In its report for the Draft Decision, GBA considered that Western Power's proposed forecast transmission capital expenditure for regulatory compliance was generally reasonable. GBA noted that regulatory compliance capital expenditure was forecast to increase by 52 per cent on average in real terms from the current access arrangement period with approximately half of this expenditure for cross-arm replacement and pole management. This is not an unexpected situation as Western

[214] Real cost escalation has been removed for comparison purposes.

Power is under pressure to improve the quality of its overhead lines in extreme and high fire risk areas. [215]

879. Taking account of GBA's advice, in the Draft Decision the Authority accepted Western Power's proposal.

880. In response to the Draft Decision, Western Power states it has increased its asset replacement expenditure by $8 million to reflect increased contractor costs and unit volumes for transmission pole management, offset by efficiencies to be achieved from strategic IT projects.

881. GBA has reviewed Western Power's revised forecast expenditure and notes that it has not reviewed the cost increases for transmission pole management in detail but, since the risks posed by wood pole failure are so serious, it considers that Western Power's current focus should be the efficient implementation of its pole management program which is best assessed through the ex-post review when determining the opening regulatory capital base at the next access arrangement review.

882. The Authority has accepted the additional costs for transmission pole management for the purposes of calculating target revenue and has not cut this investment program as it recognises that there is a need for this investment. The Authority expects that Western Power will only incur efficient costs in undertaking this work. The Authority will assess the efficiency of this expenditure at the next access arrangement review when determining the opening regulatory capital base for the fourth access arrangement period.

Table 87 Final Decision regulatory compliance capital expenditure (real $ million at 30 June 2012)[216]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal	14.0	16.7	23.3	28.9	29.4	112.3
Draft Decision	14.0	16.7	23.3	28.9	29.4	112.3
Western Power's revised proposal	18.1	19.5	24.3	29.5	29.6	121.0
Final Decision	**18.1**	**19.5**	**24.3**	**29.5**	**29.6**	**121.0**

Transmission SCADA and Communications Expenditure

883. In its report for the Draft Decision, GBA considered that Western Power's proposed forecast transmission capital expenditure for SCADA and communications were generally reasonable. In its advice to the Authority, GBA noted the following key points:[217]

215 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 7.

216 Real cost escalation has been removed for comparison purposes.

217 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 7.

- SCADA and communications expenditure was forecast to increase by 60 per cent on average in real terms from the current access arrangement period. The bulk of this increased expenditure is on asset replacement. Western Power stated that this is for the upgrade of the XA-21 master station in System Management's control room and the completion of a number of large microwave replacements.
- The master station hardware is located in System Management's control room. GBA considered whether the master station assets should be included in Western Power's capital base and, consequently, whether master station asset replacement costs should be funded from regulated transmission revenues. GBA's concern arises from the ring-fenced status of System Management and the fact that System Management's primary function under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* and the Market Rules is to operate the SWIS in a secure and reliable manner.
- It appears that, while the System Management owns software associated with generator scheduling, the control room and master station are still owned by Western Power, and System Management does not pay rental for the use of this master station. GBA was not provided with any documented agreement or contract between Western Power and System Management that defined the boundary between Western Power and System Management owned assets or specified how power system control costs are to be apportioned. This, in GBA's view, is not a satisfactory situation. It is possible that some costs are being carried by Western Power that should be carried by System Management as they relate to the performance of System Management's functions.

884. In its Draft Decision, the Authority agreed with GBA's advice and was particularly concerned with the SCADA and communications expenditure for ring-fenced aspects of System Management. It appeared to the Authority that the entire amount for the master station expenditure (which according to Table 41 of Attachment A of Western Power's access arrangement information is $15.5 million) should be removed from forecast capital expenditure. On page 132 of Attachment A of Western Power's access arrangement information, Western Power noted that the master station is a business critical system that provides the ring-fenced System Management with real-time visibility and control of the generation and transmission network, including outage and fault management, and provides data to support the Wholesale Electricity Market Rules. If this is the case, then the Authority considered that System Management should pay for it, not Western Power's customers. As a result, the Authority required Western Power's transmission capital expenditure to be adjusted to the amended forecast of master station expenditure in Table 88.

Table 88 Draft Decision forecast transmission SCADA & Communications capital expenditure Master Station XA/21 (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	2.8	3.2	2.8	3.1	3.5	15.4
Draft Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

885. Western Power has provided further information in its amended access arrangement information which notes that the SCADA Master Station XA/21 is predominantly used to monitor and control the transmission network rather than for managing and reporting generation data and monitoring compliance for the Independent Market Operator.

886. Following the new information provided by Western Power, the Authority has reconsidered its position in the Draft Decision on this expenditure and now proposes to include Western Power's proposed Master Station XA/21 expenditure. As a result, the Authority considers that Western Power's revised proposed forecast expenditure for SCADA and Communications is reasonable.

Table 89 Final Decision SCADA and communications capital expenditure (real $ million at 30 June 2012)[218]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal	14.2	11.9	12.9	18.3	18.0	75.3
Draft Decision	11.4	8.7	10.1	15.2	14.5	59.9
Adjustment to include Master Station XA/21	2.8	3.2	2.8	3.1	3.5	15.4
Final Decision	**14.2**	**11.9**	**12.9**	**18.3**	**18.0**	**75.3**

Final Decision Transmission Network Capital Expenditure

887. As noted in the discussion above, Western Power has provided revised forecasts and further information which the Authority has considered. As a result of the Authority's considerations above, the Authority's amended transmission network capital expenditure for the third access arrangement period is summarised below in Table 90.

[218] Real cost escalation has been removed for comparison purposes.

Table 90 Final Decision transmission network capital expenditure (real $ million at 30 June 2012)[219]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Draft Decision
Capacity Expansion	194.7	270.2	128.7	137.0	213.5	944.1	788.3
Customer Driven	11.9	20.3	20.3	20.3	20.3	93.1	98.9
Asset Replacement	30.7	33.1	33.2	33.2	34.5	164.7	162.5
Regulatory Compliance	18.1	19.5	24.3	29.5	29.6	121.0	112.3
Reliability	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	14.2	11.9	12.9	18.3	18.0	75.3	59.9
Final Decision	**269.6**	**355.0**	**219.4**	**238.3**	**315.9**	**1,398.2**	1,221.9
Western Power's Revised Proposal	261.2	333.8	233.2	345.7	420.6	1,594.6	

Distribution Forecast Capital Expenditure

888. Western Power's initial proposed forecast third access arrangement period distribution net capital expenditure (excluding capital contributions and gifted assets) is set out in Table 91 below, broken down into regulatory categories.

219 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

Table 91 Western Power's initial proposed distribution network capital expenditure (real $ million at 30 June 2012)[220]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion	65.1	72.3	82.7	82.4	84.3	386.7
Customer Access	132.1	129.4	130.2	128.5	129.1	649.4
Asset Replacement	157.7	166.0	170.8	179.6	190.0	864.2
Regulatory Compliance	99.1	103.4	103.6	72.7	78.4	457.2
Metering Asset Replacement	15.1	47.3	46.5	41.9	17.0	167.8
Reliability	0.6	0.6	0.6	0.6	0.6	3.0
SCADA and Communications	4.8	5.7	6.6	3.8	6.7	27.6
Smart Grid	2.5	23.9	26.2	19.7	15.0	87.3
State Underground Power Program	9.8	4.7	0.0	0.0	0.0	14.5
Total Capital Expenditure excluding real input cost escalation	**486.9**	**553.5**	**567.1**	**529.2**	**521.0**	**2,657.7**

889. In the Draft Decision, the Authority amended distribution network capital expenditure for the third access arrangement period, as indicated below in Table 92.

220 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes. The capital expenditure line provided in Table 67 included real input cost escalation. The Authority has assessed real input cost escalation separately to better assess Western Power's forecast capital expenditure..

Table 92 Draft Decision distribution network capital expenditure (real $ million at 30 June 2012)[221]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion	50.8	57.4	63.8	61.9	68.4	302.3
Customer Access	132.1	129.4	130.2	128.5	129.1	649.3
Asset Replacement	157.7	166.0	170.8	179.6	190.0	864.1
Regulatory Compliance	99.1	103.4	103.6	72.7	78.4	457.2
Metering Asset Replacement	13.6	44.3	43.5	39.2	15.5	156.1
Reliability	0.6	0.6	0.6	0.6	0.6	3.0
SCADA and Communications	4.8	5.7	6.6	3.8	6.7	27.6
Smart Grid	2.5	23.9	26.2	19.7	15.0	87.3
State Underground Power Program	9.8	4.7	0.0	0.0	0.0	14.5
Draft Decision	**471.1**	**535.6**	**545.2**	**506.0**	**503.6**	**2,561.5**
Western Power's Proposal	486.9	553.5	567.1	529.2	521.0	2,657.7

890. In response to the Authority's Draft Decision, Western Power amended its forecast distribution capital expenditure for the third access arrangement period as shown in Table 93 below.

221 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

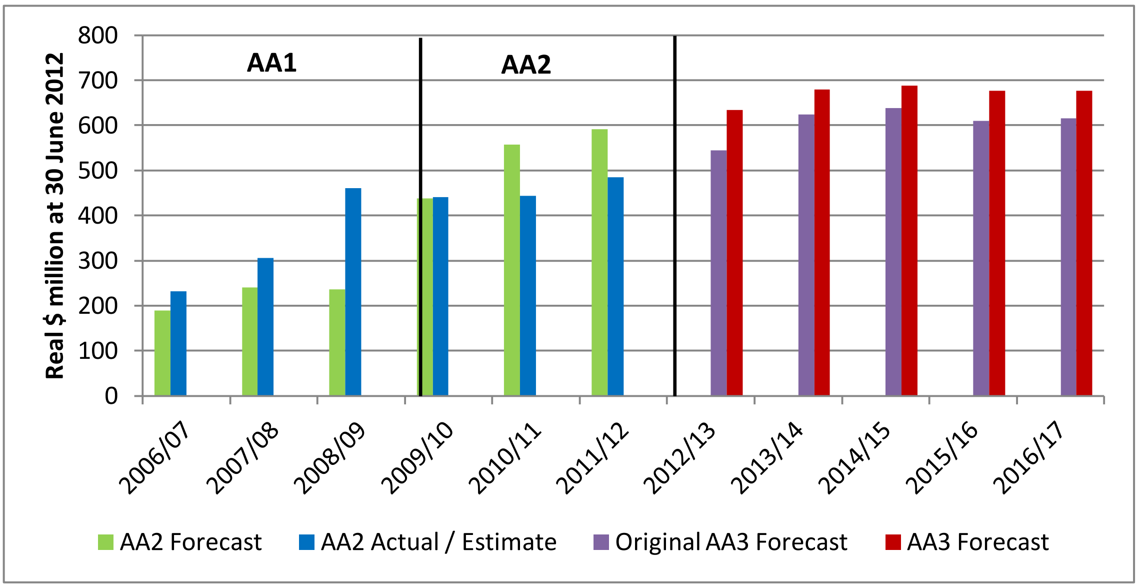
Table 93 Western Power's revised proposed distribution network capital expenditure (real $ million at 30 June 2012)[222]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Draft Decision
Capacity Expansion	60.1	64.6	71.9	81.5	82.2	360.3	302.3
Customer Access	127.7	124.8	125.7	124.0	122.5	624.8	649.3
Asset Replacement	208.6	224.5	230.8	240.4	249.0	1,153.4	864.1
Regulatory Compliance	114.0	112.2	111.5	82.7	87.9	508.2	457.2
Metering Asset Replacement	15.7	45.5	44.8	40.3	17.1	163.5	156.1
Reliability	0.6	0.6	0.6	0.6	0.6	2.9	3.0
SCADA and Communications	5.1	6.1	6.7	3.7	6.4	28.0	27.6
Smart Grid	2.5	23.6	25.8	19.4	14.5	85.8	87.3
State Underground Power Program	17.3	8.3				25.6	14.5
Total excluding real input cost escalation	**551.6**	**610.2**	**617.8**	**592.5**	**580.3**	**2,952.5**	2,561.5

891. Figure 9 below shows Western Power's proposed and revised proposed forecast distribution capital expenditure net of capital contributions and inclusive of corporate expenditure and real input cost escalation for the third access arrangement period. The 2011/12 estimated capital expenditure is the amount estimated by Western Power in its access arrangement information (September 2011) and amended access arrangement information (May 2012).

222 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

Figure 9 Distribution network capital expenditure (real $ million at 30 June 2012)



892. While the aggregate net distribution capital expenditure for the third access arrangement period has increased from Western Power's estimated 2011/12 expenditure there have also been large compositional changes in the types of capital expenditure. Western Power has forecast to spend considerably less, on average, than the current access arrangement period on reliability initiatives, the SUPP and customer connection capital expenditure. However, Western Power has forecast to spend considerably more, on average, on asset replacement, capacity expansion, regulatory compliance, metering asset replacement and Smart Grid capital expenditure. The significant driver behind the increase in Western Power's revised proposed distribution capital expenditure compared with its initial proposed expenditure is an even further increase in wood pole expenditure to undertake significantly more pole reinforcement activities.

Distribution Capacity Expansion

893. Western Power's proposed forecast capacity expansion capital expenditure of $386.7 million during the third access arrangement period was 55 per cent higher on an average annual basis than the current access arrangement period. In its report prior to the Draft Decision, GBA considered that most of Western Power's forecast expenditure was reasonable. However, GBA had recommended that some adjustment to Western Power's forecast was required.

894. The majority of Western Power's expenditure was for minor distribution network capacity expansion projects to catch up on the deferred investment during the current access arrangement period. This expenditure is focussed on reducing the risk of outages on highly loaded feeders. GBA noted that utilisation of some of Western Power's distribution feeders is greater than 80 per cent, which is high by industry standards.

895. However, GBA did not consider the transmission driven distribution capital expenditure, that is capital expenditure on the distribution network required as a result of work on the transmission network, as forecast by Western Power to be reasonable. GBA advised that it was difficult to see why the proposed distribution costs for the third access arrangement period should be, on average, greater than about 10 per cent of the associated costs of the transmission equipment that drives this

expenditure. Western Power's third access arrangement period forecasts were well above 10 per cent, particularly for 2012/13 which represented 36 per cent. Western Power's actual current access arrangement transmission driven distribution capital expenditure was well below 10 per cent of the associated transmission capital expenditure. The Authority agreed with GBA's recommendation and believed that the transmission-driven capital expenditure should be limited to 10 per cent of the transmission costs which drive this expenditure, noting that this 10 per cent limit is conservative based on historical data.

896. As discussed above in relation to transmission capital expenditure, in the Draft Decision the Authority took the view that Western Power's 2011 Annual Planning Report (**APR**) demand forecasts should be used as a basis for forecasting capital expenditure as these forecasts were the most recent estimates of demand growth. The 2011 APR forecast that demand growth during the third access arrangement period would be 40 per cent lower than Western Power assumed when it made its forecasts for growth capital expenditure requirements for the third access arrangement period.

897. As transmission-driven distribution capital expenditure is directly related to the level of transmission-driven supply capital expenditure which the Authority decided to reduce by 40 per cent, it seemed reasonable to the Authority that this expenditure also be reduced by 40 per cent. Also, GBA noted that the reduction in demand growth should correspond with the need for fewer minor distribution capacity expansion projects. However, GBA has only recommended a 20 per cent reduction rather than a 40 per cent reduction, noting that it would not expect the correlation to be as direct as that for transmission driven capital expenditure.[223] The Authority agreed that the reduction for minor distribution capacity expansion projects should be less than 40 per cent of peak demand growth and considered that 20 per cent was a reasonable approximation.

898. Taking account of GBA's advice, the Authority in its Draft Decision considered that Western Power's distribution capacity expansion capital expenditure should be adjusted as set out in Table 94 below.

Table 94 Draft Decision distribution capacity expansion capital expenditure for the third access arrangement (real $ million at 30 June 2012)[224]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power initial proposal	65.1	72.3	82.7	82.4	84.3	386.7
Adjustment to transmission driven distribution capital expenditure	(5.3)	(3.1)	(5.7)	(10.0)	(3.8)	(27.9)
Adjustment for reduced demand growth	(9.0)	(11.8)	(13.2)	(10.5)	(12.1)	(56.6)
Draft Decision	**50.8**	**57.4**	**63.8**	**61.9**	**68.4**	**302.3**

223 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 97.

224 Real cost escalation has been removed for comparison purposes.

899. In response to the Draft Decision, Western Power noted that it undertook an assessment and found that transmission-driven distribution capital expenditure was, on average, 26 per cent of its associated transmission driven supply capital expenditure. Western Power stated that, in undertaking its analysis, GBA did not compare the total cost of the transmission project and the related distribution project over the entire project lifecycle. Western Power considers that the 26 per cent proportion it calculated on historic projects is consistent with its forecast costs for transmission and associated distribution projects during the third access arrangement period.

900. Western Power also considers that the Authority has incorrectly assessed the impact of a reduction in the system wide forecast peak demand on minor distribution capacity expansion projects. While Western Power has made some adjustment for reduced demand, it noted that this work is aimed at addressing over-utilisation of distribution feeders (greater than 80 per cent at a 10 per cent probability of exceedence) and voltage compliance issues on long country feeders.

901. Western Power's revised forecast is set out in Table 95 below.

Table 95 Western Power's revised proposed distribution capacity expansion capital expenditure for the third access arrangement (real $ million at 30 June 2012)[225]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial proposal	65.1	72.3	82.7	82.4	84.3	386.7
Draft Decision	50.8	57.4	63.8	61.9	68.4	302.3
Revised Proposal	**60.1**	**64.6**	**71.9**	**81.5**	**82.2**	**360.3**

902. GBA has considered Western Power's analysis and sought further information before recommending to the Authority that limiting transmission driven distribution capacity expansion expenditure to 10 per cent of the related transmission capacity expansion is no longer supportable. However, as the Authority has not accepted Western Power's revised proposed transmission supply capital expenditure, which is the primary driver of this expenditure, transmission-driven distribution capital expenditure must be amended to be consistent with the Authority's determination of transmission supply capital expenditure. GBA calculated a reasonable provision by determining the appropriate ratio (15.2 per cent) between transmission-driven distribution expenditure and total transmission supply using Western Power's forecasts for the third access arrangement period. GBA applied this ratio to the total adjusted transmission supply amount (taking account of the reduction based on reduced demand) during the third access arrangement period and allocated the expenditure equally over each of the period. As a result, GBA recommends a $23.4 million increase to the amount the Authority determined for its Draft Decision for distribution capacity expansion capital expenditure.

903. GBA considered Western Power's lower forecast expenditure reduction for minor distribution expansion projects for reduced peak demand but remains of the view that the 20 per cent reduction it recommended for the Draft Decision is very reasonable and would provide some ability to address known weak spots in the network. GBA's

225 Real cost escalation has been removed for comparison purposes.

recommended reduction is only half the forecast reduction in demand growth over the third access arrangement period that Western Power's capacity expansion capital expenditure must provide for (discussed above at paragraphs 847 to864).

904. GBA noted that distribution capacity expansion capital expenditure is also subject to the Investment Adjustment Mechanism and that Western Power's $89.1 million asset replacement capital expenditure on distribution conductor management would help reduce voltage drop on country feeders.

905. The Authority agrees that, on the basis of the further information supplied by Western Power that the 10 per cent assumption applied in the Draft Decision for the ratio of transmission driven capital expenditure to transmission supply capital expenditure is no longer appropriate. The Authority agrees with GBA that Western Power's proposed expenditure should reflect the reduced transmission supply capital expenditure approved in this Final Decision. The Authority has reviewed GBA's methodology for determining the ratio to apply to total transmission supply capital expenditure, as noted in paragraph 902. This Authority is satisfied that the ratio recommended by GBA on the basis of this approach is reasonable to apply to the approved transmission supply capital expenditure. This will necessitate an increase to the approved distribution capacity expansion capital expenditure of $23.4 million over the third access arrangement period.

906. The Authority agrees with GBA's assessment and remains of the view that the 20 per cent reduction it required in the Draft Decision for minor distribution expansion projects is reasonable. If Western Power believes it requires further expenditure then the Investment Adjustment Mechanism will apply to this additional expenditure. The investment adjustment mechanism ensures Western Power is no worse off for not having this investment included in its forecast expenditure now, should this investment later to be determined to meet the NFIT requirements.

907. As a result, the Authority requires the adjustment to distribution capacity expansion capital expenditure as indicated in Table 96.

Table 96 Authority's Final Decision distribution capacity expansion capital expenditure for the third access arrangement (real $ million at 30 June 2012)[226]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	50.8	57.4	63.8	61.9	68.4	302.3
Adjustment to transmission driven distribution capital expenditure	6.6	3.6	3.3	4.9	5.0	23.4
Final Decision	**57.4**	**61.0**	**67.1**	**66.8**	**73.4**	**325.7**

Distribution Customer Access

908. Western Power's initial proposal for distribution customer access capital expenditure is set out in Table 97 below.

226 Real cost escalation has been removed for comparison purposes.

909. GBA's advice to the Authority for the Draft Decision considered that Western Power's forecast distribution capital expenditure for customer access was generally reasonable. GBA's report for the Draft Decision noted that customer access costs are forecast to be lower on average in real terms compared to the current access arrangement. However customer access expenditure is very difficult to forecast as it is almost entirely out of Western Power's control.[227]

910. In the Draft Decision the Authority agreed with GBA's recommendations and accepted Western Power's forecasts.

911. In response to the Draft Decision, Western Power did not provide any new information in relation to this expenditure item. The Authority therefore, has not amended the forecast approved in the Draft Decision in its Final Decision, as set out below.

Table 97 Final Decision forecast distribution customer driven capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal- accepted for Draft Decision and Final Decision						
Customer driven expenditure	204.8	202.6	206.3	205.7	209.0	1,028.4
Capital contributions	72.8	73.1	76.0	77.2	79.9	379.0
Net customer driven expenditure	132.0	129.5	130.3	128.5	129.1	649.4

Distribution Asset Replacement

912. Western Power's proposed forecast asset replacement capital expenditure of $864.2 million during the third access arrangement period was 54 per cent higher on an average annual basis than in the current access arrangement. Western Power's proposed expenditure on its wood pole replacement and reinforcement increased by almost 50 per cent compared to the current access arrangement period and formed 76 per cent of the proposed asset replacement expenditure. As noted by GBA in its report prior to the Draft Decision, Western Power's trend of increasing asset replacement capital expenditure was consistent with the experience of other distribution network service providers, as assets installed during the high growth period of the 1960s and 1970s reached the end of their economic life.

913. In its review prior to the Draft Decision, GBA advised that generally the expenditure proposed by Western Power for asset replacement was reasonable, particularly as the replacement of the identified assets was necessary to reduce safety risks caused by the network.[228]

914. The poor condition of its wood pole population poses a high risk for Western Power because of the risk to public safety from unassisted wood pole failures and the potential for such failures to start bush fires that cause extensive property damage.

[227] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.

[228] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.2.

Western Power's wood pole failure rate is significantly higher than other Australian distribution network service providers.

915. Western Power proposed to significantly increase its wood pole replacement and reinforcement rates during the third access arrangement period and included forecast capital expenditure of $748 million for this purpose. Based on its current assessment of the condition of the wood pole population, Western Power considered it would take 20 years of elevated investment before it can reach a sustainable rate of replacement. Western Power considered more aggressive timeframes but concluded that the 20 year management plan was the most achievable approach.

916. In September 2009, Western Power was issued with an Order by EnergySafety that required, among other things, that all unsupported rural poles that did not comply with required standards be replaced or reinforced by 2015. This Order followed EnergySafety audits into Western Power's management of its distribution wood pole population undertaken in 2007 and 2009.

917. In the Draft Decision, the Authority noted that it understood that EnergySafety considered Western Power's proposed wood pole management program to be inadequate and that Western Power's preferred investment approach did not fully meet the Order's requirements.

918. The Authority also noted that Western Power's unassisted wood pole failure rate has been the subject of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament.[229] The report of the Legislative Council's Standing Committee on Public Administration and the asset management review[230] undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program.

919. In its Draft Decision, the Authority noted that the level of wood pole renewal and replacement required in order to comply with the Safety Order was a matter for Western Power to resolve with the technical regulator, EnergySafety, and was not for the Authority to determine.

920. In its report to the Authority prior to the Draft Decision, GBA considered that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented are available, particularly if Western Power successfully addresses issues related to records management. However, the Authority considered that any efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the actual expenditure. As a result, the Authority did not adjust Western Power's proposed forecast distribution asset replacement capital expenditure.

921. As noted in the Draft Decision, the Authority is aware that another network service provider has carried out an evaluation comparing steel and wood poles and, in its' particular situation, established that steel poles had a lower life cycle cost and provided additional benefits compared with wood poles. The Authority expects that Western Power has undertaken similar analysis.

[229] *Unassisted Failure*: Report 14, Standing Committee on Public Administration, Report 14, Legislative Council, Parliament of Western Australia, January 2012.

[230] GHD Asset Management System Review Final Report October 2011.

922. The Authority noted in its Draft Decision that the investment needed for wood pole management may change as Western Power further develops its understanding of what is required. To ensure that Western Power is incentivised to do this in an efficient manner, the Authority decided that, for the third access arrangement period, expenditure relating to wood pole management should be subject to the investment adjustment mechanism. This will then enable expenditure higher than forecast to be recovered to the extent that it is demonstrated to be efficient expenditure, and will provide Western Power with a return on that investment from the date it is incurred. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts. All of these provisions ensure Western Power is not constrained to only spend what is allowed in the current forecast.

923. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 14

The proposed access arrangement revisions must be amended to include expenditure relating to wood pole management in the investment adjustment mechanism.

924. In response to the Draft Decision, Western Power has incorporated wood pole management into the investment adjustment mechanism in its revised proposed access arrangement as required by Draft Decision Amendment 14. Western Power has also proposed the inclusion of its stay wire program in the investment adjustment mechanism. Stay wires are cables attached between a transmission or distribution pole and an anchor point to support wood poles that have high forces applied to them by overhead equipment. Stay wire investment is required to address non-compliant stay and insulators which may become live and become a safety issue.

925. The Authority received two submissions during the second round consultation period which specifically addressed Draft Decision Amendment 14. The Western Australian Department of Finance notes that the Authority has provided Western Power with the flexibility to spend beyond its forecast on wood pole replacement which it believes will assist Western Power to efficiently implement the program.[231] WACOSS is also supportive of the Authority's approach to include wood pole investment in the investment adjustment mechanism. However, WACOSS was concerned about price shocks if Western Power accelerates its wood pole replacement program faster than projected in the Draft Decision,[232] and provided some suggestions to the Authority to manage the risk of price shocks.

926. The Authority does not consider that the inclusion of stay wire expenditure in the investment adjustment mechanism for the third access arrangement period is appropriate. The Authority's requirement to include wood pole replacement in the investment adjustment mechanism is a one-off and the Authority does not consider that wood pole asset replacement would be included in the investment adjustment mechanism past the third access arrangement period. The Authority only required the inclusion of wood pole expenditure because Western Power was not expected to meet its obligations under an EnergySafety Order and the potential investment

231 May 2012, Government of Western Australia – Department of Finance, Submission on the Authority's Draft Decision, p. 4.

232 May 2012, Western Australian Council of Social Service Inc, Submission on the Authority's Draft Decision, p. 9.

needed for wood pole management may have change as Western Power further develops its understanding of what is required. Western Power has revised its regulatory compliance expenditure for a significant increase in distribution stay replacement during the third access arrangement which is considered below and which the Authority has accepted as reasonable. Not including this expenditure in the investment adjustment mechanism does not prevent Western Power from undertaking more work than forecast, as any expenditure which meets the NFIT will be added to the capital base in the next access arrangement period and will be adjusted to include a return on, and depreciation allowance, for this investment from the year it was incurred.

Required Amendment 12

The revised proposed access arrangement revisions must be amended to remove all stay wire programs from the investment adjustment mechanism.

927. Western Power's amended access arrangement information notes that its revised distribution asset replacement expenditure now incorporates a significant increase in the pole reinforcement volumes from 60,000 to 265,000 and an increase in the unit rates for its asset replacement programs. This has led to an increase in forecast expenditure of $332.5 million. A further $9.4 million has been added in relation to other equipment replacements. This has been offset by around $30 million in Strategic Program of Work (SPOW) efficiencies. In total, Western Power has increased its proposed asset replacement expenditure to $1,153.3 million from $864.2 million in its initial proposal.

928. Western Power's revised proposal is set out in Table 98 below.

Table 98 Western Power's revised proposed asset replacement capital expenditure for the third access arrangement (real $ million at 30 June 2012)[233]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial Proposal	157.7	166.0	170.8	179.6	190.0	864.2
Draft Decision	157.7	166.0	170.8	179.6	190.0	864.2
Revised Proposal	**208.6**	**224.5**	**230.8**	**240.4**	**249.0**	**1,153.3**

929. In its advice to the Authority, GBA noted that the majority of the proposed increase in asset replacement expenditure relates to Western Power's new pole reinforcement strategy that has been developed in conjunction with EnergySafety and that wood pole management will now be subject to the investment adjustment mechanism.

930. The Authority has considered Western Power's revised proposed forecast distribution expenditure for asset replacement and has decided to accept the revised amount for the purposes of the Final Decision as set out in Table 99 below. The Authority expects that Western Power will only incur efficient costs in undertaking this work. The Authority notes that it will assess this efficiency of this expenditure through an ex-

233 Real cost escalation has been removed for comparison purposes.

post review in setting the opening regulatory capital base for the fourth access arrangement period.

931. For the purposes of the Investment Adjustment Mechanism, the following expenditure forecast (as set out in Table 99 below) will be used to establish any adjustment at the next access arrangement review. This category of expenditure needs to be separately identified in Western Power's revenue model, as is the case for expenditure already covered by the Investment Adjustment Mechanism. The access arrangement must be amended to set out the relevant expenditure forecasts which will be used to calculate the Investment Adjustment Mechanism.

Table 99 Final Decision Wood Pole Management Forecast Expenditure for the third access arrangement (real $ million at 30 June 2012)[234]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Total	166.1	187.4	196.2	204.7	213.7	968.1

Required Amendment 13

The revised proposed access arrangement revisions must be amended to include the investment adjustment mechanism values as indicated in Table 99.

Western Power's revenue model must also be amended to include a separate regulatory category for wood pole management .

Distribution Regulatory Compliance

932. Western Power initially proposed forecast expenditure of $457.2 million during the third access arrangement period for distribution regulatory compliance capital expenditure.

933. GBA considered that Western Power's forecast distribution regulatory compliance expenditure was generally reasonable. GBA noted that regulatory compliance expenditure would increase by 19 per cent on average in real terms from the current access arrangement period. This has been driven by expenditure that will replace or refurbish assets that are at risk of initiating bush fires, improve overhead connection for increased public safety, target a reduction in the number of outages lasting longer than 12 hours that trigger penalty payments, and enhancements to the low voltage network to meet the requirements of the *Electricity Act 1945*.

934. In its Draft Decision, the Authority agreed with GBA's assessment that Western Power's forecast expenditure for distribution regulatory compliance was reasonable.

935. In response to the Draft Decision, Western Power has revised its proposed distribution regulatory compliance capital expenditure to $508.2 million during the third access arrangement period, an increase of $51 million. Western Power's revised

234 Real cost escalation has been removed for comparison purposes.

regulatory compliance expenditure is predominantly due to an increased volume for replacement of stay wires (4,670 to 24,400), increase in unit rates and an accelerated streetlight switchwire program (1,050 km to 4,096 km of switchwire). Western Power's revised proposal is set out in Table 100 below.

Table 100 Western Power's revised proposed regulatory compliance capital expenditure for the third access arrangement (real $ million at 30 June 2012)[235]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial Proposal	99.1	103.4	103.6	72.7	78.4	457.2
Draft Decision	99.1	103.4	103.6	72.7	78.4	457.2
Revised Proposal	**114.0**	**112.2**	**111.5**	**82.7**	**87.9**	**508.3**

936. GBA has assessed Western Power's revised proposed distribution regulatory compliance capital expenditure and, has recommended to the Authority that there is a need to accelerate the streetlight switchwire program.

937. While the Authority has not accepted Western Power's proposal to include stay wire investment in the investment adjustment mechanism for the reasons outlined above, it considers that the increased volume proposed by Western Power for distribution stay replacement is reasonable. The Authority notes that Western Power's revised proposed expenditure appears to be the outcome of a discussion with EnergySafety. The Authority also considers the accelerated streetlight switchwire program to be reasonable considering the safety risk posed which unfortunately resulted in a fatality in January 2011.

938. As a result, the Authority has decided that, given the state of Western Power's current network, it is reasonable to allow the additional proposed expenditure by Western Power and has accepted Western Power's revised forecast of $508.3 million.

Distribution Metering Asset Replacement

939. Western Power's proposed forecast expenditure of $167.8 million during the third access arrangement period for meter asset replacement covered two programs – new, and replacement of standard meters and the installation of three phase smart meters to replace 280,000 three phase meters which Western Power states do not comply with section 6.8(d) of the Metering Code. GBA advised that most of Western Power's forecast expenditure on distribution meter asset replacement was reasonable. However, GBA recommended that some adjustments to Western Power's forecast were required.

940. Western Power's proposed new and replacement meter component reduced by 8 per cent on average in the third access arrangement period compared to the current access arrangement period. However, this expenditure line item did not include three phase meters in the third access arrangement period as these are being replaced under the smart meter program. Western Power stated that one-third of the 30,000 meters it replaced each year in the current access arrangement period were three phase meters. As a result, to make a fair comparison with the expenditure level in the

235 Real cost escalation has been removed for comparison purposes.

current access arrangement period, GBA took account of the 10,000 three phase meter replacements per annum that have not been included in the third access arrangement period expenditure for new and replacement of standard meters. GBA concluded that it would have expected this line item to have decreased by 18 per cent in the third access arrangement period. As a result, GBA has recommended a 10 per cent reduction in the forecast for new and replacement meters.

941. GBA considered that Western Power's forecast costs for its smart meter program to replace non-compliant three phase meters was overstated by up to 15 per cent compared to benchmarked results from the Victorian advance meter rollout program. GBA noted that this analysis did not provide for the allocation of indirect costs. However, even with an allocation of indirect costs, GBA advised that the forecast cost of the smart meter program was still overstated. As a result, GBA recommended a 5 per cent reduction to the forecast cost of this program.[236]

942. In its Draft Decision, the Authority considered that it is reasonable that the new and replacement of standard meter capital expenditure be reduced by 10 per cent to reflect the current access arrangement levels of expenditure and that the smart meter program be reduced by 5 per cent, as the costs for this program appear to be overstated based on benchmarking analysis.

943. As a result, the Authority required that Western Power's distribution capital expenditure be adjusted according to the amended forecast for metering asset replacement in Table 101 below.

Table 101 Draft Decision distribution metering asset replacement capital expenditure for the third access arrangement (real $ million at 30 June 2012)[237]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Metering Asset Replacement – proposed	15.1	47.3	46.5	41.9	17.0	167.8
Adjustment to new and replacement of standard meters capital expenditure	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)	(6.6)
Adjustment to smart meters capital expenditure	(0.1)	(1.7)	(1.7)	(1.4)	(0.2)	(5.1)
Metering Asset Replacement – amended	**13.6**	**44.3**	**43.5**	**39.2**	**15.5**	**156.1**

944. In response to the Draft Decision, Western Power has accepted the Authority's adjustments to new and replacement of standard meters and smart meter capital expenditure. However, Western Power has added expenditure of $12.5 million

236 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 99-100.

237 Real cost escalation has been removed for comparison purposes.

(including real cost escalation) for high voltage tariff metering to be installed at Verve generator sites. Western Power's revised proposal is set out in below.

Table 102 Western Power's revised proposed metering asset replacement capital expenditure for the third access arrangement (real $ million at 30 June 2012)[238]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial Proposal	15.1	47.3	46.5	41.9	17.0	167.8
Draft Decision	13.6	44.3	43.5	39.2	15.5	156.1
Revised Proposal	**15.7**	**45.5**	**44.8**	**40.3**	**17.1**	**163.5**

945. Western Power's amended access arrangement information notes that in a final recommendations report to the Minister for Energy on the *Electricity Industry Metering Code 2005* prepared by the Office of Energy (now the Public Utilities Office) published in August 2011, a proposed amendment has been included which will require the majority of Verve Energy sites to install meters capable of meeting the accuracy requirements of the Metering Code before 30 June 2017.

946. Western Power notes that it is unclear which party (Western Power or Verve Energy) should pay for this meter installation, although it is of the view that Verve Energy is responsible. However, Western Power has proposed the inclusion of these costs in its forecast distribution metering asset replacement expenditure in case it is required to pay these costs when the amended Metering Code is gazetted.

947. GBA has recommended that the Authority should be very reluctant to approve such costs. GBA notes that if provision for such costs were included in forecast expenditure, the incentive for Western Power to resist the change is reduced. GBA notes that a service provider in a competitive environment would reasonably be expected to resist legislative changes that adversely affect costs. GBA highlight that, should the changes to the Metering Code not eventuate, Western Power would capture a windfall gain.

948. The Authority agrees with GBA's assessment that Western Power should have an incentive to resist legislative changes that adversely affect costs and that if these legislative amendments do not proceed, Western Power would receive a windfall gain at the expense of its customers. The Authority understands that amendments to the Metering Code are still under consideration by the Public Utilities Office. As there is no certainty that the Metering Code will be amended to require this expenditure to install new meters at Verve Energy sites and Western Power itself states that it believes these costs should be met by Verve Energy if the change occurs,, the Authority does not accept Western Power's forecast expenditure for amendments to the Metering Code.

949. The Authority remains of the view that metering asset replacement expenditure should reflect the amounts approved in the Draft Decision as set out in Table 101.

238 Real cost escalation has been removed for comparison purposes.

Distribution Reliability Capital Expenditure

950. GBA's advice to the Authority for the Draft Decision considered that Western Power's forecast distribution capital expenditure for reliability was generally reasonable.

951. GBA's report noted that the forecast distribution reliability expenditure was 95 per cent lower, on average, in real terms from the current access arrangement. This reflects Western Power's perception that customers are generally satisfied with the level of service currently provided.[239]

952. In the Draft Decision the Authority agreed with the findings by GBA that Western Power's forecast expenditure was reasonable.

953. In its response to the Draft Decision, Western Power has not amended its forecast of distribution reliability expenditure.

954. The Authority has not altered its view since the Draft Decision and accepts Western Power's forecasts.

Distribution SCADA and Communications Capital Expenditure

955. Western Power proposed forecast expenditure of $27.6 million during the third access arrangement period for distribution SCADA and Communications capital expenditure.

956. GBA advised that given that the proposed expenditure was quite small relative to transmission SCADA and communications and that distribution SCADA is important to network functionality, it considered the expenditure to be reasonable.

957. In the Draft Decision, the Authority agreed with the recommendation from GBA that Western Power's proposed distribution SCADA and communication expenditure was reasonable.

958. In response to the Draft Decision, Western Power has increased its forecast expenditure by $1.3 million to enhance its ENMAC system to increase compliance with its Type 1 Compliance obligations. The Authority's technical adviser considers this expenditure to be reasonable and that it will increase Western Power's ability to monitor its low voltage network.

959. The Authority has accepted the advice of its technical consultant and, for the purposes of the Final Decision, has amended the Draft Decision forecast expenditure to include the additional expenditure as set out in Table 103 below.

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[239] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.

Table 103 Final Decision SCADA and communications capital expenditure for the third access arrangement (real $ million at 30 June 2012)[240]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial Proposal	4.8	5.7	6.6	3.8	6.7	27.6
Draft Decision	4.8	5.7	6.6	3.8	6.7	27.6
Adjustment for ENMAC System expenditure	0.4	0.6	0.3	0.0	0.0	1.3
Final Decision	**5.2**	**6.3**	**6.9**	**3.8**	**6.7**	**28.9**

960. The small increase relates to system changes required to improve compliance with Type 1 obligations. The Authority considers the proposed expenditure to be reasonable and has accepted the revised proposal for the Final Decision.

Distribution Smart Grid Capital Expenditure

961. GBA's advice to the Authority for the Draft Decision considered that Western Power's forecast distribution capital expenditure for smart grid was generally reasonable.

962. GBA noted in its report to the Authority that smart grid forecast expenditure in the third access arrangement period is expected to increase significantly from the current access arrangement, as Western Power has decided to replace 3 phase meters with new smart grid meters. Western Power has undertaken studies that show that the costs of implementing a smart grid program are substantial but that the benefits, particularly to customers through lower wholesale electricity prices, would more than offset this with a net benefit of $208 million over time. GBA considered that the quantified societal benefits should be monitored on an ongoing basis and be compared to the modelled results.[241]

963. In the Draft Decision, the Authority agreed with GBA's recommendation that Western Power's smart grid forecast expenditure was reasonable. The Authority intends to monitor smart grid expenditure to see if the societal benefits do materialise as expected by Western Power.

964. In response to the Draft Decision, Western Power has not provided any new information. Therefore the Authority has maintained its position from the Draft Decision as set out in Table 104 below.

240 Real cost escalation has been removed for comparison purposes.

241 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.

Table 104 Final Decision Smart Grid capital expenditure for the third access arrangement (real $ million at 30 June 2012)[242]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Initial Proposal	2.5	23.9	26.2	19.7	15.0	87.3
Draft Decision	2.5	23.9	26.2	19.7	15.0	87.3
Final Decision	**2.5**	**23.9**	**26.2**	**19.7**	**15.0**	**87.3**

Distribution State Underground Power Program Capital Expenditure

965. In its advice to the Authority for the Draft Decision, GBA recommended that Western Power's forecast distribution capital expenditure for customer access, reliability, smart grid and the SUPP was generally reasonable.

966. In its report, GBA noted that Western Power has forecast net expenditure (capital contributions are excluded) for the SUPP of $14.5 million for the first two years of the third access arrangement period. This expenditure will meet Western Power's obligations under round 5 of the SUPP. As Western Power currently has no commitment to further rounds of the SUPP, no additional capital expenditure was forecast for the remaining years of the regulatory period[243].

967. In the Draft Decision, the Authority agreed with GBA's view that Western Power's forecast expenditure for the SUPP was reasonable.

968. In response to the Draft Decision, Western Power has not provided further information in relation to this expenditure. The Authority has therefore maintained the same forecast as was approved for the Draft Decision as set out in Table 105 below.

Table 105 Final Decision State Underground Power Program capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's initial proposal- accepted for Draft and Final Decision						
Customer driven expenditure	39.2	18.9	0.0	0.0	0.0	58.1
Capital contributions	29.4	14.2	0.0	0.0	0.0	43.6
Net customer driven expenditure	9.8	4.7	0.0	0.0	0.0	14.5

242 Real cost escalation has been removed for comparison purposes.

243 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.

Final Decision Distribution Network Capital Expenditure

969. As noted in the discussion above, Western Power has provided revised forecasts and further information which the Authority has considered. As a result of the Authority's considerations, the Authority's amended distribution network capital expenditure for the third access arrangement period is summarised below in Table 106.

Table 106 Final Decision distribution network capital expenditure (real $ million at 30 June 2012)[244]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total	Draft Decision
Capacity Expansion	57.4	61.0	67.1	66.8	73.4	325.7	302.3
Customer Access	132.0	129.5	130.3	128.5	129.1	649.3	649.4
Asset Replacement	208.6	224.5	230.8	240.4	249.0	1,153.3	864.1
Regulatory Compliance	114.0	112.2	111.5	82.7	87.9	508.3	457.2
Metering Asset Replacement	13.6	44.3	43.5	39.2	15.5	156.1	156.1
Reliability	0.6	0.6	0.6	0.6	0.6	3.0	3.0
SCADA and Communications	5.2	6.3	6.9	3.8	6.7	28.9	27.6
Smart Grid	2.5	23.9	26.2	19.7	15.0	87.3	87.3
State Underground Power Program	9.8	4.7	0.0	0.0	0.0	14.5	14.5
Total	**543.7**	**607.0**	**616.9**	**581.7**	**577.2**	**2,926.5**	**2,561.5**
Western Power's Revised Proposal	551.6	610.2	617.8	592.5	580.3	2,952.5	

Corporate Capital Expenditure

970. Western Power's initial forecast third access arrangement period corporate capital expenditure is provided in Table 107 below, broken down into regulatory categories. The majority of Western Power's proposed corporate capital expenditure relates to projects that are currently underway, including:

- property purchases;
- purchasing plant and equipment;

244 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

- refurbishing head office and major depots;
- replacing IT hardware and software; and
- delivering major enterprise systems.

Table 107 Western Power's Initial Proposed Forecast Corporate capital expenditure (real $ million at 30 June 2012)[245]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT	43.9	41.5	25.5	27.1	27.6	165.6
Business Support	31.9	30.7	21.9	21.9	17.8	124.2
Total	**75.7**	**72.2**	**47.4**	**49.0**	**45.5**	**289.8**

971. In the Draft Decision, the Authority did not accept Western Power's proposal. The Authority's assessment of forecast corporate capital expenditure, as determined in the Draft Decision, is summarised in Table 108 below.

Table 108 Draft Decision corporate capital expenditure for third access arrangement (real $ million at 30 June 2012)[246]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT	40.8	38.4	22.4	23.6	23.6	148.8
Business Support	31.9	30.7	21.9	21.9	17.8	124.2
Total	**72.7**	**69.1**	**44.3**	**45.5**	**41.4**	**273.0**

972. In response to the Draft Decision, Western Power revised its proposed expenditure as shown in Table 109 below.

Table 109 Western Power's Revised Proposed Forecast Corporate capital expenditure (real $ million at 30 June 2012)[247]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT	46.0	42.5	25.8	27.0	27.5	168.7
Business Support	32.7	31.5	21.7	21.7	17.6	125.2
Total	**78.6**	**74.0**	**47.5**	**48.6**	**45.1**	**293.9**

973. Each element of expenditure is considered below.

245 Capital expenditure is exclusive of real cost escalation for comparison purposes.

246 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

247 Capital expenditure is exclusive of real cost escalation for comparison purposes.

Information Technology

974. The majority of Western Power's initial proposed forecast for IT capital expenditure was dedicated to new IT infrastructure and improving major enterprise level information systems.

975. The remaining IT expenditure ($39.6 million) relates to "business as usual" expenditure. This expenditure relates to undertaking ongoing minor business system enhancements. GBA noted in its advice to the Authority for the Draft Decision that Western Power's business as usual IT expenditure was forecast to increase by 73 per cent per annum on average over its actual current access arrangement capital expenditure. GBA noted that Western Power had not provided an explanation for the significant increase and, as a result, GBA advised that this expenditure should be adjusted on a pro-rata basis to be consistent with the average current access arrangement period expenditure.[248]

976. Without an explanation for the significant increase in business as usual IT expenditure, the Authority considered that the expenditure should be adjusted on a pro-rata basis to ensure it is consistent with the annual average of actual current access arrangement expenditure. As a result, in the Draft Decision, the Authority required that Western Power's information technology capital expenditure be adjusted according to the amended forecast in Table 110.

Table 110 Draft Decision Forecast of Information Technology capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT – Proposed	43.9	41.5	25.5	27.1	27.6	165.6
Adjustment to IT business as usual expenditure	(3.1)	(3.1)	(3.1)	(3.5)	(4.0)	(16.8)
IT – Amended	**40.8**	**38.4**	**22.4**	**23.6**	**23.6**	**148.8**

977. In response to the Draft Decision, Western Power did not accept the Authority's adjustments to business as usual expenditure and increased its forecast further to include $2.6 million for enhanced systems to comply with Type 1 licence obligations[249] and $2.2 million for the development of IT and system enhancements to ensure the success of its people and culture initiative.

978. Western Power's proposed $2.2 million during the third access arrangement period for IT and system enhancements required for its people and culture initiative, includes development of an online system for managing performance appraisal and automated HR forms to promote simplified human resource policies and processes. As noted in paragraph 445 with regard to the operating expenditure for this initiative, GBA considers that the cost of the program should be funded by the shareholder and not customers.

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248 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 109.

249 Type 1 licence obligations impose requirements on Western Power relating to the times during which a customer may be disconnected for non-payment, non-disconnection of customers that rely on electricity for life support and the provision of notice of planned outages to affected life support customers amongst other requirements.

979. The Authority's technical adviser has recommended that the expenditure in relation to ensuring compliance with Type 1 licence obligations should be accepted. On the basis of this advice, the Authority has included this expenditure in its Final Decision.

980. However, the Authority does not consider the forecast costs should be increased for additional expenditure in relation to the people and culture initiative and has not included this in its Final Decision. As noted in paragraph 446 in relation to the operating expenditure for this initiative, the Authority considers that the shareholder would have to meet these cultural change costs in a competitive environment. The Authority's Final Decision is set out in Table 111 below.

Table 111 Final Decision Forecast of Information Technology capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	40.8	38.4	22.4	23.6	23.6	148.8
Adjustment for Type 1 Obligations expenditure	0.8	1.1	0.5	0.1	0.1	2.6
Final Decision	**41.6**	**39.5**	**22.9**	**23.7**	**23.7**	**151.4**

Business Support

981. Western Power's business support capital expenditure reflects refurbishment and construction of its head office and new depot locations at Busselton and Jerramungup to accommodate an increased capital works program, as well as capital items to support office and depot accommodation. In its advice to the Authority for the Draft Decision, GBA advised that Western Power's forecast capital expenditure for business support was reasonable.[250] In the Draft Decision, the Authority took the view that, without any conflicting information to suggest otherwise, the proposed expenditure was reasonable.

982. In response to the Draft Decision, Western Power has increased its forecasts to include $2.4 million for the establishment and management of an in-house wood pole testing facility. The Authority's technical adviser has recommended that these additional costs should be accepted. On the basis of this advice from GBA, the Authority has increased the forecast expenditure approved in the Draft Decision as set out in Table 112 below.

Table 112 Final Decision business support capital expenditure for third access arrangement (real $ million at 30 June 2012)[251]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Draft Decision	31.9	30.7	21.9	21.9	17.8	124.2
Wood pole testing facility	1.2	1.2	0.0	0.0	0.0	2.4
Final Decision	**33.1**	**31.9**	**21.9**	**21.9**	**17.8**	**126.6**

250 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 110-111.

251 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

Final Decision Corporate Capital Expenditure

983. The Authority's Final Decision in relation to corporate capital expenditure for the third access arrangement period is summarised below in Table 113. The amended corporate expenditure will be allocated on a pro-rata basis to the transmission and distribution notional new facilities investment.

Table 113 Final Decision corporate capital expenditure for third access arrangement (real $ million at 30 June 2012)[252]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT	41.6	39.5	22.9	23.7	23.7	151.4
Business Support	33.1	31.9	21.9	21.9	17.8	126.6
Total	**74.7**	**71.4**	**44.8**	**45.6**	**41.5**	**278.0**

Indirect Capital Expenditure

984. The costs in the preceding paragraphs relating to capital expenditure forecasts all include an element of indirect costs. Indirect costs are costs which are not directly incurred on a network project but are incurred in achieving the delivery of projects more widely (such as project management, maintaining computers and facilities for operational staff etc) and are allocated to projects. In its initial proposal, Western Power included the following amounts of indirect costs within capital expenditure as set out in Table 114 below.

Table 114 Total Indirect Costs included in Western Power's Initial Capital Expenditure Forecasts (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's proposal	136.0	138.9	145.6	153.5	144.3	718.3

985. In its advice to the Authority for the Draft Decision, GBA recommended a reduction of 13.7 per cent in indirect costs for operating expenditure which is discussed in paragraph 421. In GBA's view a similar reduction of 13.7 per cent for indirect costs for capital expenditure was also warranted.

986. As a result, the Authority required that Western Power's indirect costs for capital expenditure be adjusted according to the amended forecast in Table 115.

Table 115 Draft Decision Forecast of Indirect Cost Allocation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Western Power's proposal	136.0	138.9	145.6	153.5	144.3	718.3
Draft Decision	**117.4**	**119.9**	**125.7**	**132.5**	**124.6**	**620.1**
Amendment required	(18.6)	(19.0)	(19.9)	(21.0)	(19.7)	(98.2)

252 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

987. As noted in paragraph 423 in relation to indirect operating expenditure, Western Power in response to the Draft Decision, did not accept the 13.7 per cent reduction in its initial indirect expenditure forecast. As noted in paragraph 424, GBA assessed Western Power's response and concluded that it saw no reason why GBA's recommended indirect expenditure in its report prior to the Draft Decision should be adjusted upwards.

988. The Authority has assessed Western Power's revised proposed indirect expenditure and accepts GBA's advice, consistent with its assessment of indirect costs in relation to operating expenditure (paragraph 425) and has not revised the amounts determined at the Draft Decision.

Input Cost Escalation

989. In the Draft Decision the Authority amended the real labour and materials escalation factors proposed by Western Power. The Authority considered that the proposed escalation factors overstated reasonable escalation factors for these input costs. The reasons for this are discussed further in paragraphs 464 to487 and 505 to 513.

990. For the purposes of the Draft Decision, the Authority calculated a notional amount of real cost escalation for labour based on the escalation factors and expenditure forecasts for transmission and distribution determined by the Authority. The Authority amended the total distribution and transmission capital expenditure forecasts accordingly.

991. The total impact of the labour escalation factors was forecast by Western Power to be \$288.3 million for capital expenditure[253] (calculated in real \$ as at 30 June 2012). In the Draft Decision the Authority determined that only \$183.4 million is reasonable.

992. The total impact of the materials escalation factors was forecast by Western Power to be \$13 million for capital expenditure[254] (calculated in real \$ terms as at 30 June 2012). In the Draft Decision the Authority did not allow any increase for materials escalation.

Table 116 Draft Decision Real Input Escalation for Capital Expenditure (real \$ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Labour Escalation						
Western Power Proposal	13.9	31.9	57.5	85.9	99.1	288.3
Draft Decision	13.3	24.0	37.1	47.4	61.6	183.4
Materials Escalation						
Western Power Proposal	-0.3	0.7	2.8	4.6	5.2	13.0
Draft Decision	0.0	0.0	0.0	0.0	0.0	0.0

253 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 193.

254 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 193.

993. In response to the Draft Decision, Western Power has updated its forecast of real input escalation based on updated escalation rates. Its revised forecasts are set out in Table 117 below.

994. The Authority reviewed Western Power revised escalation rates and remains of the view that the amended escalation rates used for the Draft Decision are appropriate. The Authority's consideration of this matter is contained in paragraphs 461 to 524.

995. Rather than continuing with the calculation methodology in the Draft Decision of determining an amount for real cost escalation for labour by using a ratio of the revised index values proposed by Western Power compared with the amended index calculated by the Authority, the Authority sought further information from Western Power on the share of labour out of its revised capital expenditure forecast. The Authority has used the share derived from Western Power's numbers and applied this to the Final Decision allowed labour escalation rate and total capital expenditure (prior to inclusion of input cost escalation) for each year of the third access arrangement period. The Authority considers that this methodology is more reasonable as it accounts for the approved level of capital expenditure forecast rather than basing it on a level of capital expenditure that was not approved.

996. The total impact of the revised labour escalation factors was forecast by Western Power to be $280.7 million for capital expenditure (calculated in real dollars as at 30 June 2012). The Authority amended this amount in the Final Decision to $175.1 million during the third access arrangement period.

997. The total impact of the revised materials escalation factors was forecast by Western Power to be $10.8 million for capital expenditure (calculated in real dollar terms as at 30 June 2012). The Authority has not allowed any increase for materials escalation in the Final Decision.

Table 117 Final Decision Real Input Escalation for Capital Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Labour Escalation						
Western Power Revised Proposal	10.1	29.0	52.9	79.8	108.9	280.7
Final Decision	**7.6**	**21.6**	**30.2**	**39.5**	**53.9**	**152.8**
Materials Escalation						
Western Power Revised Proposal	-0.1	1.8	2.9	3.1	3.1	10.8
Final Decision	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Conclusion on Application of the Section 6.51A Test

998. Under section 6.51 of the Access Code, the forecast total costs for providing covered services for the third access arrangement period may include costs in relation to forecast new facilities investment that at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when the forecast new facilities investment is forecast to be made.

999. In the Draft Decision, after having regard to information provided by Western Power and advice from GBA, the Authority considered that the entire amount of forecast new facilities investment that was not subject to a contribution, and that Western Power

proposed to take into account in determining the forecast total costs, did not satisfy the new facilities investment test and, hence, did not satisfy the test of section 6.51A or the requirements of section 6.51.

1000. The Authority considered that a lesser amount of forecast new facilities investment (capital expenditure) satisfied the requirements of section 6.51 of the Access Code, as detailed in paragraphs 803 to 992. The Authority determined the total capital cost of providing covered services as set out in Table 118.

Table 118 Draft Decision forecast capital expenditure (real $ million at 30 June 2012)[255] [256] [257] [258]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission						
Western Power proposal	337.5	255.9	340.0	503.3	390.5	1,827.2
Draft Decision	**275.0**	**353.1**	**200.6**	**225.2**	**274.4**	**1,328.3**
Distribution						
Western Power proposal	543.5	621.4	635.8	610.4	613.8	3,025.0
Draft Decision	**515.9**	**586.6**	**590.1**	**557.9**	**559.8**	**2,810.3**
Total						
Western Power proposal	881.0	877.3	975.8	1,113.8	1,004.3	4,852.2
Draft Decision Transmission & Distribution **Total**	**790.9**	**939.7**	**790.7**	**783.1**	**834.2**	**4,138.6**

1001. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 15

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as listed in Table 62 [of the Draft Decision].

1002. After having regard to the further information provided by Western Power in its Amended Access Arrangement Information, and advice from GBA, the Authority considers that the entire amount of forecast new facilities investment that is not subject to a contribution, and that Western Power proposes to take into account in determining the forecast total costs, does not satisfy the new facilities investment test and, hence, does not satisfy the test of section 6.51A or the requirements of section 6.51.

255 Amended transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

256 Amended transmission and distribution expenditure is allocated a portion of amended real input escalation based on Western Power's proposed allocation of transmission and distribution network operating expenditure.

257 Amended transmission and distribution expenditure is allocated portion of amended indirect capital expenditure based on the ratio of Western Power's proposed allocation of these costs.

258 Proposed transmission and distribution expenditure excludes inventory and mid-year timing assumption.

1003. The Authority considers that a lesser amount of forecast new facilities investment (capital expenditure) satisfies the requirements of section 6.51 of the Access Code. The Authority has determined the total capital cost of providing covered services as set out in Table 119 below. Corporate costs, indirect costs and escalation costs are shown separately in the table below. These costs have been allocated between distribution and transmission based on Western Power's proposed allocation proportions consistent with the Draft Decision.

Table 119 Final Decision forecast capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission						
Western Power revised proposal	293.2	368.5	264.5	390.4	477.8	1,794.3
Final Decision :						
Transmission Costs	**269.6**	**355.0**	**219.4**	**238.3**	**315.9**	**1,398.2**
Corporate Costs	**28.1**	**26.9**	**16.9**	**17.2**	**15.6**	**104.7**
Indirect Cost Adjustment	**(5.9)**	**(6.9)**	**(5.5)**	**(6.3)**	**(6.9)**	**(31.4)**
Input Escalation	**2.4**	**7.6**	**7.7**	**11.1**	**18.4**	**47.3**
Total	**294.2**	**382.6**	**238.5**	**260.3**	**343.0**	**1,518.8**
Distribution						
Western Power revised proposal	608.2	679.7	688.2	676.9	677.1	3,330.0
Final Decision:						
Distribution Costs	**543.7**	**607.0**	**616.9**	**581.7**	**577.2**	**2,926.5**
Corporate Costs	**46.6**	**44.5**	**27.9**	**28.4**	**25.9**	**173.3**
Indirect Cost Adjustment	**(12.7)**	**(12.1)**	**(14.4)**	**(14.7)**	**(12.8)**	**(66.8)**
Input Escalation	**5.2**	**14.0**	**22.5**	**28.3**	**35.5**	**105.5**
Total	**582.8**	**653.3**	**652.9**	**623.7**	**625.8**	**3,138.5**
Combined						
Western Power revised proposal	901.4	1,048.1	952.6	1,067.3	1,154.9	5,124.3
Final Decision:						
Transmission and Distribution	**813.3**	**962.0**	**836.3**	**820.0**	**893.1**	**4,324.7**
Corporate Costs	**74.7**	**71.4**	**44.8**	**45.6**	**41.5**	**278.0**
Indirect Cost Adjustment	**(18.6)**	**(19.0)**	**(19.9)**	**(21.0)**	**(19.7)**	**(98.2)**
Input Escalation	**7.6**	**21.6**	**30.2**	**39.5**	**53.9**	**152.8**
Total	**877.0**	**1,036.0**	**891.4**	**884.1**	**968.8**	**4,657.3**

Required Amendment 14

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as set out in Table 119 above.

1004. The Authority notes that all new facilities investment to occur in the third access arrangement period will still have to be assessed to determine whether it satisfies the new facilities investment test, either at the time of revisions to the access arrangement for the fourth access arrangement period or at the time of any application by Western Power under sections 6.71 and 6.72 of the Access Code.

Inventory

1005. In the proposed revisions to the access arrangement, Western Power included an amount relating to inventory assets in the opening capital base for the third access arrangement period and made an annual adjustment to the capital base reflecting changes to the stock of inventory. Western Power stated that the inclusion of inventory was to "recover the financing costs associated with efficiently holding these assets for users of covered services".

1006. The Authority considered this proposal in paragraphs 663 to 666 as part of its assessment of the opening capital base. For the reasons stated in those paragraphs, the Authority determined in the Draft Decision that Western Power's proposed adjustment to include the costs of inventory in the capital base should not be allowed.

1007. In the Draft Decision, the Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 16

Western Power's proposed adjustment to the capital base for the third access arrangement period for changes to the stock of inventory must be removed.

1008. In response to the Draft Decision, Western Power has accepted the required amendment and removed inventory from the capital base. The Authority is satisfied that Draft Decision Amendment 16 has been complied with.

Mid-Year Timing Assumption

1009. In the proposed revisions to the access arrangement, Western Power adopted a mid-year timing assumption for capital expenditure to establish the opening capital base and the notional capital base throughout the third access arrangement period. Western Power stated that the 'mid-year timing was appropriate to simulate the impact of incurring new facilities investment throughout the year'.[259] It also noted the timing of its "summer ready" program required a significant portion of its investment program to be completed by December each year.

1010. Western Power stated that, to be consistent with the target revenue end-of-year cash flow timing assumption, capital expenditure added to the capital base effectively on a mid-year basis must be adjusted to an end-of-year cash flow. It notes this has the effect of capitalising the first six months of costs and provides for them to be recovered over the life of the assets. It achieved this by adjusting the new facilities investment in each year for the time value of money for six months by applying the following factor to new facilities investment and adding this amount to the capital base. Western Power noted that its proposed revision is in line with the approach currently used by the AER in its 'post-tax revenue model'.

1011. The Authority has considered this proposal in paragraphs 681 to 694 as part of its assessment of the opening capital base. For the reasons stated in those paragraphs the Authority determined in the Draft Decision that Western Power's proposed adjustment to adopt a mid-year timing assumption for capital expenditure in the notional capital base throughout the third access arrangement period should not be allowed.

[259] Revised Access Arrangement Information, Section 10.2.6, p. 243.

1012. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 17

The proposed revised access arrangement must be amended to remove any amounts in relation to a mid-year timing assumption.

1013. In response to the Draft Decision, Western Power has accepted the required amendment and adjusted its proposed notional capital base accordingly. The Authority is satisfied that Western Power has complied with Draft Decision Amendment 17.

Depreciation

1014. Under section 6.70 of the Access Code, an access arrangement must provide for the depreciation of the network assets comprising the capital base, including the economic lives of each network asset or group of network assets, the depreciation method to be applied to each network asset or group of network assets and the circumstances in which the depreciation of a network asset may be accelerated.

1015. Western Power's proposed method and assumptions for calculation of depreciation allowances are set out in clauses 5.3.1 to 5.3.6 of the proposed access arrangement revisions.

1016. In determining the total costs for the third access arrangement period, Western Power calculated depreciation allowances using the straight-line method, with assumptions of average residual lives of existing assets included in the initial capital base values of the transmission and distribution networks, and total asset lives for new assets introduced to the capital base as new facilities investment. Western Power has revised its assumptions for the asset lives of transmission SCADA and communications, transmission IT and distribution IT assets.

1017. Asset life assumptions for each asset category in the capital base are shown in Table 120.

Table 120 Asset lives applied for calculation of depreciation allowances[260]

Asset category	Assumed asset life (years)		
	Existing assets at 30 June 2006	New Assets 1 July 2006 to 30 June 2012	New assets from 1 July 2012
Transmission			
Cables	38.1	55	55
Steel towers	41.3	60	60
Wood poles	20.9	45	45
Metering	26.1	40	40
Transformers	25.5	50	50
Reactors	27.0	50	50
Capacitors	23.1	40	40
Circuit breakers	28.2	50	50
SCADA & communications	11.4	34.15	*11*
IT	4.2	16.85	*6*
Other non-network assets	12.0	16.85	16.85
Land and easements	Not applicable	Not applicable	Not applicable
Distribution			
Wooden pole lines	14.5	41	41
Underground cables	36.9	60	60
Transformers	16.9	35	35
Switchgear	13.5	35	35
Street lighting	1.2	20	20
Meters and services	9.2	25	25
IT	9.8	10.16	*6*
SCADA & communications	10.2	10.16	10.16
Other non-network assets	11.3	10.16	10.16
Land and easements	Not applicable	Not applicable	Not applicable

1018. In the Draft Decision, the Authority considered the revised asset lives for these assets and took the view that the revised asset lives were reasonable, except for those relating to transmission SCADA & Communications. Based on advice from its technical adviser,[261] the Authority considered that 11 years would be realistic if this only related to SCADA master station equipment. However, this asset category includes fibre optic, control cables and remote terminal equipment which the Authority's technical adviser, GBA, advised should last much longer. The Authority considers that 20 years would be a reasonable weighted average life for this asset class, consistent with the requirements of section 6.70 of the Access Code.

1019. The Authority, accordingly, required the following amendment to the proposed revised access arrangement.

260 Revised Access Arrangement Supplementary Information, Revenue Model

261 16 March 2012, GBA email correspondence.

Draft Decision Amendment 18

Western Power's revised access arrangement must be amended to reflect a 20 year economic life for depreciation purposes for transmission SCADA and communications.

1020. In response to the Draft Decision, Western Power has not accepted this required amendment. Western Power has provided further analysis of the assets within this category to explain how it arrived at a weighted average life of 11 years. The Authority has reviewed this analysis and considers it to be reasonable. More than 80 per cent of the assets relate to electronic equipment which has asset lives of between seven and 11 years. In light of the additional information provided, the Authority is satisfied that an asset life of 11 years is appropriate.

1021. At clause 5.3.4 of the proposed access arrangement revisions, Western Power indicates that accelerated depreciation will be applied to distribution assets that will be decommissioned as a result of the SUPP undertaken by Western Power on behalf of the Western Australian Government. This principle of accelerated depreciation is unchanged from the current access arrangement. The Authority is satisfied with the level of accelerated depreciation for the decommissioned assets as a result of the SUPP.

Table 121 Valuation of accelerated depreciation for the third access arrangement period (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Transmission	0	0	0	0	0
Distribution					
Wooden pole lines	-2.6	-0.3	0	0	0
Transformers	-0.7	-0.1	0	0	0
Switchgear	-0.2	0.0	0	0	0
Total distribution	-3.4	-0.5	0	0	0
Total	**-3.4**	**-0.5**	**0**	**0**	**0**

1022. In its advice to the Authority for the Draft Decision, GBA noted that Western Power had not included accelerated depreciation in relation to wooden poles or meters that are replaced. Whilst many of these assets will have reached the end of their useful life and already be fully depreciated, GBA considered there will be instances of some such assets not being fully depreciated. The consequence of this is that the cost of those assets will continue to be recovered over the notional life of the asset, and therefore included in future charges, rather than being written off immediately and included in current charges.

1023. Consequently in the Draft Decision, the Authority required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 19

Western Power must establish the value of any redundant assets included in its notional capital base for the third access arrangement period and include accelerated depreciation to fully write them off.

1024. In response to the Draft Decision, Western Power has not accepted the amendment and considers it is not consistent with the roll-forward method and requires more revenue to be recovered from customers during the period compared to Western Power's proposal.

1025. The Authority has considered this matter further in relation to determining the opening capital base. As set out in paragraph 680, the Authority considers that any potential redundant assets would, most likely, be within the initial asset base taken on at the beginning of the first access arrangement period. The Authority has reviewed the remaining asset lives of these assets, in particular those relating to meters and wood poles and notes that metering assets will be fully depreciated by the end of the third access arrangement and wood poles will be fully depreciated by the end of the fourth access arrangement period.

1026. The Authority considers the remaining asset value of any redundant assets would be small and, in any case, will be written off over a relatively short period of time. The Authority recognises also that it would not be possible to attribute regulatory net asset values to specific assets, so any assessment of accelerated depreciation could only be done by applying broad brush calculations. The Authority therefore, on balance, does not require Draft Decision Amendment 19 to be implemented.

Final Decision Notional Capital Base Values for the Third Access Arrangement Period

1027. As noted in the discussion above, following the Draft Decision, Western Power has provided revised forecasts and further information which the Authority has considered. As a result of the Authority's considerations above, the Authority has recalculated revised values of the notional capital base for the third access arrangement period in accordance with the Authority's determinations under this Final Decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in determination of total costs and target revenue.

1028. The revised notional capital base at the end of the third access arrangement period (30 June 2017) for the transmission network of $3.576.3 million compares with a value of $3,924.1 million proposed by Western Power in its amended access arrangement information (in dollar values of 30 June 2012).

1029. The revised notional capital base at the end of the third access arrangement period (30 June 2017) for the distribution network of $5,862.9 million compares with a value of $6,129.6 million proposed by Western Power in its amended access arrangement information (in dollar values of 30 June 2012).

1030. The calculation of the revised capital base values is shown in Table 122 and Table 123 below. Equity raising costs are discussed in paragraphs 1187 to 1194.

Table 122 Final Decision forecast transmission network capital base (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	5 Years	Draft Decision
Opening asset value	**2,554.7**	**2,765.1**	**3,056.9**	**3,193.5**	**3,346.2**	**2,554.7**	**2,593.2**
New facilities investment[262]	294.2	382.6	238.5	260.3	343.0	1,518.6	1,318.3
Inventory	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-year timing assumption	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	(85.2)	(93.8)	(103.5)	(110.0)	(117.5)	(510.0)	(504.3)
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equity raising costs	1.4	3.0	1.6	2.4	4.5	12.8	9.9
Final Decision Closing asset base	**2,765.1**	**3,056.9**	**3,193.5**	**3,346.2**	**3,576.3**	**3,576.3**	**3,417.2**
Western Power Revised Proposal	2,860.9	3,133.1	3,291.6	3,568.9	3,924.1	3,924.1	

262 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

Table 123 Final Decision forecast distribution network capital base (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	5 Years	Draft Decision
Opening asset value	**3,855.6**	**4,244.8**	**4,687.9**	**5,107.1**	**5,491.5**	**3,855.6**	**3,932.0**
New facilities investment[263]	582.8	**653.3**	**652.9**	**623.7**	**628.8**	3,138.5	2,798.3
Inventory	0.0	**0.0**	**0.0**	**0.0**	**0.0**	0.0	0.0
Redundant assets	0.0	**0.0**	**0.0**	**0.0**	**0.0**	0.0	0.0
Depreciation	(194.3)	**(214.3)**	**(237.7)**	**(242.0)**	**(255.6)**	(1,143.9)	(1,139.2)
Accelerated depreciation	(3.4)	**(0.5)**	**0.0**	**0.0**	**0.0**	(3.9)	(3.9)
Equity raising costs	4.1	**4.6**	**4.1**	**2.6**	**1.3**	**16.7**	**12.1**
Final Decision Closing Asset Base	4,244.8	**4,687.9**	**5,107.1**	**5,491.5**	**5,862.9**	**5,862.9**	**5,599.1**
Western Power Revised Proposal	4,386.7	**4,846.0**	**5,289.9**	**5,717.2**	**6,129.6**	6,129.6	

263 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

Return on Regulated Capital Base

Access Code Requirements

1031. Section 6.64 of the Access Code requires that an access arrangement set out the weighted average cost of capital (**WACC**) for a covered network. Under section 6.65 of the Access Code, the Authority may from time to time publish a determination of its preferred methodology for calculating the WACC in access arrangements. If such a determination is in effect at the time of an access arrangement review, the WACC must be determined using that methodology; otherwise the WACC must be calculated in a manner consistent with section 6.66 of the Access Code.

1032. On 22 April 2010 the Authority issued a notice advising that its preferred WACC Methodology (published on 25 February 2005), had expired and hence no longer applied to covered electricity networks under the Access Code. The Authority also advised that it had decided not to issue a new determination on the preferred WACC methodology for covered electricity networks. As a consequence, the WACC must be estimated in a manner consistent with section 6.66 of the Access Code.

1033. Section 6.66 of the Access Code requires that a WACC calculation:

- must represent an effective means of achieving the Code objective and the objectives in section 6.4; and
- must be based on an accepted financial model such as the Capital Asset Pricing Model (**CAPM**).

1034. Section 6.4 of the Access Code requires that the price control in an access arrangement must (among other things) provide the service provider with an opportunity to earn revenue sufficient to cover its forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Overall Rate of Return initially proposed by Western Power

1035. For the current access arrangement period, the target revenue was determined in real dollar-value terms. A real pre-tax WACC was applied to the regulatory asset base of the regulated business to derive the return on capital, one component of the target revenue. This WACC estimate was set by reference to a range of WACC input parameters, which were derived from ranges of values determined by the Authority for the input parameters in the CAPM, and market observations of risk free rates and costs of debt. The WACC input parameters were based on a 'benchmark' efficient network service provider, consistent with current Australian regulatory practice. Calculating a WACC based on a benchmark efficient network service provider provides greater incentives for regulated providers to pursue efficient funding arrangements. The real pre-tax WACC was set at 7.98 per cent in the current access arrangement.

1036. In the proposed revisions to the access arrangement, Western Power proposed a real pre-tax WACC of 8.82 per cent. This WACC value was derived by Western Power on the advice of its consultants for WACC inputs, using a different method to that adopted by the Authority for the purposes of the current access arrangement.

1037. The values of input parameters in the determination of the WACC values for both the current access arrangement and the proposed revisions to the access arrangement are summarised as follows:

Table 124 Approved WACC in the Current Access Arrangement and Western Power's Proposed WACC (September 2011)

Parameter	Western Power's Approved WACC for AA2[264]	Western Power's Original Proposal for AA3[265]
Nominal risk free rate of return (%)	5.51	5.4
Inflation rate (%)	2.47	2.7
Real risk free rate (%)	2.97	2.63
Equity beta	0.5 - 0.8	0.9 - 1.1
Market risk premium (%)	5.0 - 7.0	6.5 - 8.0
Debt to total value (%)	60	60
Debt margin (%)	4.205 - 4.315 (including debt raising costs of 0.125%)	3.96 - 4.43 (including debt raising cost of 0.125%)
Effective tax rate (%)	30	30
Value of imputation credits (gamma, %)	57-81	25
Range for the real pre-tax WACC (%)	6.59 - 8.32	8.49 - 10.25
Real pre-tax WACC (%)	**7.98**	**8.82**

1038. Western Power established its proposed WACC value on the basis of a nominal risk free rate and a debt margin derived from capital market data over a 20-business day averaging period to 31 May 2011.

1039. Western Power indicated that it would seek an agreement with the Authority on the averaging period or "sampling period" to determine the market-based WACC parameters for the Authority's Final Decision (such as the estimates of the risk free rate and debt risk premium). Western Power also indicated that the agreed averaging period would be kept confidential until the Authority delivers its Final Decision.[266] In the Draft Decision, the Authority noted that provision for such an agreement by a regulator exists under the National Electricity Rules (sections 6.5.2(c) and 6A.6.2(c)). However, the Access Code does not provide any guidance to the Authority about how to make decisions about the averaging period.

[264] Economic Regulation Authority, 2009 Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 4 December 2009, Table 76, p. 236.

[265] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, Tables 76-8, pp. 247-8.

[266] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 257.

1040. The Authority has accepted the averaging period proposed by Western Power because it covered a period that was in the future (at the time that it was proposed), yet was still close to the time that the Final Decision was expected to be released, and hence could not be selected with certainty to benefit Western Power. Acceptance of averaging periods suggested by service providers is consistent with previous decisions of the Authority.

Draft Decision

1041. The Authority did not approve Western Power's proposal in relation to the rate of return of 8.82 per cent, which was equivalent to a real post-tax WACC of 6.17 per cent. The Authority concluded that a real post-tax rate of return of 3.87 per cent was appropriate. The reasons for this decision are detailed in the following sections. The Draft Decision included the following amendment.

Draft Decision Amendment 20

Western Power's Proposed Revisions must be amended to adopt a real post-tax rate of return of 3.87 per cent.

Western Power's Response to the Draft Decision

1042. In response to the Draft Decision, Western Power has not accepted the Authority's required amendment and has put forward a revised proposal. Western Power's revisions include reports from the following consultants:

- Competition Economists Group (**CEG**)'s advice on: (i) the estimate of equity beta; (ii) the estimate of the debt risk premium; and (iii) the consistency issue between the estimates of the market risk premium (**MRP**) and the risk-free rate of return from the Authority's Draft Decision.
- Strategic Finance Group (**SFG**)'s advice on the estimates of equity beta; and
- Ernst & Young (**E&Y**)'s advice on the applications of "other" CAPM frameworks to estimate the cost of capital for Western Power.

1043. Western Power derived its revised estimates of the WACC value on the basis of a nominal risk-free rate and a debt risk premium from the capital market data over a 20-trading day period to 30 March 2012.

1044. The values of the input parameters in the determination of the WACC for both the Authority's Draft Decision and Western Power's revised Access Arrangement are summarised in Table 125 below.

Table 125 The Cost of Capital (WACC) in the Authority's Draft Decision and Western Power's revised proposed WACC

Parameter	Draft Decision[267]	Western Power's Revised WACC[268]
Nominal risk free rate (%)	3.67	4.21 [4.21 – 5.99]
Inflation rate (%)	2.55	2.42
Gearing (%)	60	60
Debt Risk Premium (%)	2.027	3.80 [3.80 – 4.16]
Equity beta	0.65	0.80 [0.80 – 1.0]
Market Risk Premium (%)	6.0	7.75 [6.5 – 8.5]
Gamma (%)	25	25
Nominal Post-tax Cost of Debt (%)	5.82	8.01
Nominal Post-tax Cost of Equity (%)	7.57	10.41
Real post-tax WACC (%)	3.87	6.39 [6.00 – 7.97]

1045. In the revised proposed revisions to the access arrangement, Western Power has proposed a real post-tax WACC of 6.39 per cent. This WACC estimate was derived by Western Power on the advice of its various consultants for the WACC parameters partly on the basis of the following rationale:

- Western Power is of the view that the term of the risk free rate should be 10 years. Its revision is different from the term of 5 years adopted in the Authority's Draft Decision.
- Western Power argued that its credit rating should be BBB, not A- (A minus) as adopted in the Draft Decision.
- Western Power revised its estimates of debt risk premium of 3.80 per cent using Bloomberg's fair value curves. The 10-year BBB fair value curve was extrapolated from the Bloomberg's 7-year BBB fair value curve and the spread between 10-year and 7-year AAA fair value curves. It is noted that Bloomberg

[267] Economic Regulation Authority, 2012, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, Table 88, p. 206.

[268] Western Power, 2012, Response to the Economic Regulation Authority's March 2012 Draft Decision, Table 63, p. 147.

ceased its estimates of these AAA fair value curves in June 2010. Western Power did not agree that the Authority's bond-yield approach should be used to estimate the debt risk premium.

- Western Power considered that the market risk premium (**MRP**) falls within the range of 6.5 per cent and 8.5 per cent, with the revised point estimate of 7.75 per cent. Western Power argued that the MRP was revised upwards in response to a significant reduction in the observed yields for Australian Commonwealth Bonds. Its revision is different from the MRP of 6 per cent adopted in the Draft Decision.
- Western Power argued that the equity beta should be 0.8 to offset the "aggressiveness" of other aspects of the Authority's Draft Decision.

1046. In addition, Western Power also raised two fundamental issues about the estimates of the WACC parameters being:

- inconsistency between the MRP and the risk free rate of return in the Authority's Draft Decision; and
- the applications of different capital asset pricing models (namely the Black CAPM; the Fama-French CAPM; the Zero-beta Fama-French CAPM, together with the Sharpe-Lintner CAPM) to estimate the return on equity.

Public Submissions in response to the Draft Decision

1047. A number of submissions received in response to the Authority's Draft Decision commented on the assessment of the WACC for Western Power:

- WAMEU;
- Grid Australia;
- WACOSS;
- Department of Finance;
- Horizon Power;
- Energy Networks Association;
- Energy Made Clean;
- Landfill Gas and Power Pty Ltd; and
- Alinta Energy (Australia) Pty Ltd.

1048. Most of the above-mentioned public submissions indicated their general position, without detailed discussion. Energy Networks Association and Grid Australia submissions deal with almost all of the parameters for the estimates of the WACC. The issues raised in these submissions will be addressed separately for each WACC parameter, together with other relevant public submissions on the same WACC issue.

1049. Energy Networks Association considered the rate of return allowed by the Authority to be insufficient to ensure stable and efficient investment signals to Western Power.

They observed that a real post-tax ‘vanilla’ cost of capital of 3.87 per cent is significantly below that allowed to network service providers elsewhere in Australia.[269]

1050. The Department of Finance was concerned that a low WACC would result in an insufficient return to the network operator for its investment in assets and this could deter efficient investment in the network resulting in reduced reliability over the long term. It encouraged the Authority to:

- undertake a practical “sense-check” of the outcome of its deliberations to ensure that both long term financial sustainability and network reliability are assured;
- balance the regulatory approach of using a benchmarked, ‘efficient’ cost of debt with the use of Western Power’s actual cost of debt in its WACC calculation for its final determination; and
- consider the importance of regulatory certainty and how it impacts Western Power and indirectly, its end customers, in the context of the proposed change from a pre-tax real WACC framework.[270]

1051. Grid Australia was concerned that the Authority’s low WACC estimate had the potential to reduce investor certainty in the southern and eastern states by acting as a precedent for other regulators, noting that the low WACC estimate assumes a cost of debt below the rate at which a stand-alone business can borrow.[271]

1052. Horizon Power suggested it would be advisable to give service providers sufficient notice of changes such as a move to a post-tax WACC so that they are able to fully prepare for and model the implications of this significant amendment to regulatory methodology.[272]

Final Decision

1053. Taking account of the information provided with Western Power’s amended access arrangement information and public submissions received, the Authority has reviewed and updated its Draft Decision. The considerations of the Authority are set out in paragraphs 1298 to 1843.

1054. Western Power proposed the averaging period or “sampling period” to determine the market-based WACC parameters for the Authority’s Final Decision (such as the estimates of the risk free rate and the debt risk premium). The Authority accepted Western Power’s proposed averaging period, which covers the period of 20-business days until 15 June 2012 inclusive. As a result, all market-based WACC parameters in this Final Decision were derived from the averaging period proposed by Western Power.

[269] Energy Networks Association, Submission on Western Power’s Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, pp. 1- 2.

[270] Department of Finance, Submission on Western Power’s Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, pp. 1-2.

[271] Grid Australia, Submission on Western Power’s Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 1.

[272] Horizon Power, Submission on Western Power’s Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 3.

1055. In summary, the point estimates that the Authority considers may reasonably be applied to the parameters of the CAPM and other parameters in the entire WACC framework in estimating the rate of return for Western Power are as shown in Table 126 below.

Table 126 Authority's Required Amendments to Western Power's Proposed Parameter Values for Determination of a Rate of Return as at 15 June 2012 (Per cent)

Parameter	Final Decision (Per cent)	Draft Decision (Per cent)
Nominal Risk Free Rate $\left(R_f\right)$	2.52	3.67
Real Risk Free Rate $\left(R_f^r\right)$	0.41	1.09
Inflation Rate π_e	2.10	2.55
Debt Proportion $\left(D\right)$	60	60
Equity Proportion $\left(E\right)$	40	40
Cost of Debt: *Debt Risk Premium (DRP)*	2.708	2.027
Cost of Debt: *Debt Issuing Cost (DIC)*	0.125	0.125
Cost of Debt: *Risk Margin (RM)*	2.833	2.152
Australian Market Risk Premium (MRP)	6.00	6.00
Equity Beta $\left(\beta_e\right)$	65	65
Corporate Tax Rate $\left(T_c\right)$	30	30
Franking Credit $\left(\gamma\right)$	25	25
Nominal Cost of Debt $\left(R_d^n\right)$	5.35	5.82
Real Cost of Debt $\left(R_d^r\right)$	3.19	3.19
Nominal Pre Tax Cost of Equity $\left(R_e^{n,\text{pre-tax}}\right)$	8.28	9.77
Real Pre Tax Cost of Equity $\left(R_e^{r,\text{pre-tax}}\right)$	6.05	7.04
Nominal After Tax Cost of Equity $\left(R_e^{n,\text{post-tax}}\right)$	6.42	7.57
Real After Tax Cost of Equity $\left(R_e^{r,\text{post-tax}}\right)$	4.23	4.89

Table 127 Estimates of WACC (Per cent)

WACC	Final Decision (Per cent)	Draft Decision (Per cent)
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	4.33	4.73
Nominal After Tax WACC $\left(WACC_n^{\text{post-tax}}\right)$	5.78	6.52
Real After Tax WACC $\left(WACC_r^{\text{post-tax}}\right)$	3.60	3.87

1056. The Authority does not approve Western Power's revision in relation to the real, post-tax rate of return of 6.39 per cent.

1057. Table 63 of the Amended Access Arrangement Information must be changed to reflect the relevant values in Table 126 and Table 127 of this Final Decision.

Required Amendment 15

In relation to Rate of Return, Table 63 of the Amended Access Arrangement Information must be amended to reflect the relevant values of CAPM and WACC parameters in Table 126 and Table 127 of this Final Decision

Treatment of Capital Contributions

Proposed Revisions

1058. Western Power in its proposed revised access arrangement (September 2011) included $240.5 million in its target revenue for net tax costs associated with forecast capital contributions and gifted assets provided by customers.[273] This represented approximately 25 per cent of the forecast capital contributions and gifted assets in AA3.

1059. Western Power stated that these tax costs arise due to the timing differences between the initial tax paid on receipt of the capital contributions and gifted assets and the subsequent depreciation tax shield benefit provided over the life of the assets. It noted that this net cost occurs because capital contributions and gifted assets are treated as revenue by the accounting standards applicable to Western Power.[274]

1060. Western Power calculated the tax cost by taking account of:

- circularity arising from the revenue and tax impact of recovering the tax costs;
- dividend imputation franking credits passed through to its shareholder; and
- statutory tax depreciation benefit, which offsets the tax costs incurred in later years.

1061. Western Power considered circularity arises because a customer's payment of tax costs is treated as revenue, which increases the value of taxable income. This in turn requires the payment of additional tax. Western Power calculate that netting off the benefits arising from dividend imputation franking credits and statutory tax depreciation benefits from the resulting increase in tax leads to a net increase in tax liabilities of around 25 per cent of the value of the contribution.

1062. In the revised proposed revisions to the access arrangements (May 2012), Western Power did not accept the Authority's requirement – set out in the Draft Decision – that it exclude capital contributions (that is, gifted assets and cash contributions) from the tax account.

1063. Western Power proposes instead that for AA3:

- forecast capital contributions be included as revenue in the tax module in the year of receipt, increasing Western Power's tax liabilities in that year, and hence increasing the allowable tax building block revenue requirement in order to cover the tax liability; and
- historic and forecast capital contributions be included in the taxable asset base and depreciated, providing a tax shield over time, which reduces tax liabilities, and hence reduces the allowable revenue requirement in the out-years.

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273 Western Power 2011, *Revised access arrangement information*, September, Section 12.6, p. 285.

274 Australian Accounting Standards Board 2009, *Interpretation 18* "Transfer of Assets from Customers", www.aasb.gov.au.

1064. Western Power's argument for rejection of the Authority's requirement, and hence inclusion of capital contributions for purposes of determining the tax building block, may be summarised as follows: [275]

- capital contributions and gifted assets, and the tax costs associated with them, are forward-looking and efficient costs of providing covered services;
- capital contributions are treated as revenue under tax law, leading to a tax liability;
- recovering the tax liability from the contributor could increase the required contribution by up to 25 per cent;
- this tax liability should be paid by the broader customer base, as to do otherwise would create a disincentive for investment in Western Australia, which plays an important role in State development;
- the tax associated with a particular transaction can only be estimated having regard to the entity's overall tax profile, hence the estimated tax costs are not directly related to the provision of the capital contributions, and this leads to associated risks for any attempt to recover tax costs from users;
- other regulators allow inclusion.

Submissions

1065. The Urban Development Institute of Australia (**UDIA**) submitted that exclusion of capital contributions would result in 'a significant financial impost on the new homebuyer', urging that the requirement not be implemented without further analysis of the impact on the end energy consumer.[276] UDIA states that shifting the taxation liability to developers for gifting the asset would add a $1,500 to the cost per housing lot. The UDIA argues that it is economically effective for Western Power to pay for taxation, and shifting the tax liability to home buyers is in breach of the Authority's function to maintain a competitive, efficient and fair commercial environment for the benefit of the Western Australian community.

1066. The Energy Networks Association (**ENA**) submitted that it is concerned that the Authority has created disincentives for future investment in Western Australia by not allowing Western Power to recover net tax costs associated with forecast capital contributions and gifted assets. ENA considers that the regulatory regime should provide for the recovery of tax costs associated with these assets through the taxation building block.

1067. Horizon Power agreed with Western Power that the net tax costs arising from capital contributions and gifted assets should be recovered from customers and not borne by the company. Horizon Power states that to do otherwise would mean service providers would be treated inconsistently compared to eastern states service providers.

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275 Western Power 2012, *Amended access arrangement information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 draft decision*, www.erawa.gov.au, p. 166.

276 Urban Development Institute of Australia 2012, *Submission to the Economic Regulation Authority: Draft Decision*, www.erawa.com.au, May.

1068. Main Roads noted that the adoption of this treatment of tax costs would impact on Main Roads' practices for relocating existing Western Power infrastructure for roadwork. These relocations are undertaken at Main Roads' cost under the existing legislation. The cost of the relocations could rise considerably in some cases and it could also affect the timeframes for utility services relocations (which is already an issue for Main Roads). Main Roads envisage that the impact on local governments would be similar for the works they undertake on their roads. Main Roads suggests that the tax costs be shared across the entire customer base by allowing Western Power to recover them through network tariffs.

Considerations of the Authority

1069. The Authority in its Draft Decision rejected the inclusion of capital contributions in the taxation analysis for the purpose of determining Western Power's revenue on the basis that:[277]

- capital contributions are not added to the regulatory asset base (**RAB**) and therefore no depreciation or return is included in the revenue requirement in relation to contributed assets – to include capital contributions in the taxable asset base (**TAB**) would be inconsistent with this approach;[278]
  - the exclusion of capital contributions in AA2 was Western Power's choice at the AA2 reset, to reverse the inclusion which had applied for AA1;
  - the switch in treatment from AA1 to AA2 resulted in (deferred) revenue , due to the effect of exclusion of forecast capital contributions bringing forward revenue (refer paragraphs 2093 and 2274 to 2275 of this decision);
- taxation costs relating to gifted assets or cash contributions should be borne by customers who make use of those assets, not by other users on the system;
- a better approach would be for Western Power to recover such costs through negotiation with the party providing the capital contribution.

1070. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 21

No amounts in relation to tax on capital contributions may be included in Target Revenue.

1071. As noted above, Western Power did not accept the Authority's requirement.

1072. The Authority addresses each of Western Power's arguments, summarised at paragraph 1064, in what follows.

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277 Economic Regulation Authority 2012, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, www.erawa.gov.au, p. 209.

278 This was Western Power's choice at the AA2 reset and resulted in the (deferred) revenue windfall they received – as exclusion of capital contributions brings forward

Forward looking efficient costs of providing covered services

1073. In its revised proposed revisions to the access arrangement (May 2012), Western Power seeks to have the tax cost associated with capital contributions passed on to its broader customer base, thereby rejecting the Authority's Draft Decision that it exclude capital contributions for tax purposes:[279]

> Western Power does not accept this amendment as it penalises those customers that are required to pay a capital contribution or give assets to Western Power, even though those contributions relate to assets through which covered services are provided by Western Power.

1074. Including the capital contribution in the regulatory tax building block would lead to the broader customer base paying for a significant portion of the tax liability of Western Power, rather than the developer. Specifically, customers would pay for Western Power's tax liability up front by way of increased tariffs, and then receive a stream of reduced tariffs in the out-years, due to the tax depreciation shield reducing tariffs through the tax module. However, the NPV does not sum to zero – customers would end up paying a net 25 per cent of the value of the contributed assets to Western Power.[280]

1075. In consequence, including capital contributions in the regulatory tax building block would lead to Western Power receiving NPV revenue up-front from the broad customer base for an asset which, by definition, only benefits the contributor. This violates the principle of user pays, creates a cross subsidy, and is therefore not economically efficient. The approach therefore does not meet the objective set out at section 2.1 of the Access Code.

1076. Western Power supports its argument for inclusion by stating:[281]

> Under section 6.4(a) of the Access Code target revenue is to be set to recover the forward looking and efficient costs of providing covered services. Section 2.10 of the Access Code requires Western Power to undertake and fund any required work subject to receiving capital contributions. Capital contributions and gifted assets, and the tax costs associated with them, are forward-looking and efficient costs of providing covered services.

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279 Western Power 2012, *Amended access arrangement information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 draft decision*, www.erawa.com.au, p. 166.

280 The initial tax liability is 30 per cent of the contribution. Western Power estimate that circularity – for example relating to the requirement to pay tax on the additional compensation in the tax building block for the initial tax liability – lifts the initial payment from 30 per cent to around 43 per cent. Western Power further estimates that taking account of imputation credits reduces the tax cost from 43 per cent to 29 per cent. Finally, Western Power notes that taking account of the subsequent tax depreciation shield benefit further reduces the net tax cost to a 'grossed up' tax expense of around 25 per cent of the initial capital contribution or gifted asset value (see Western Power 2011, *Access arrangement information for 1 July 2012 to 30 June 2017*, www.erawa.gov.au, pp. 285-286).

281 Western Power 2012, *Amended access arrangement information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 draft decision*, www.erawa.com.au, p. 166.

1077. However, the Access Code also provides:[282]

> 6.51 For the purposes of section 6.4(a)(i)... the forward-looking and efficient costs of providing *covered services* may include costs in relation to *forecast new facilities investment* for the *access arrangement period* which at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when the *forecast new facilities investment* is forecast to be made.
>
> **Test for adding new facilities investment 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 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) [which refers to efficiently minimising costs]; 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.

1078. This indicates that forward-looking and efficient costs *may* include new investment, if it satisfies the New Facilities Investment Test (**NFIT**), or if it is subject to a contribution *and* the Authority approves it.

1079. As noted above, the current AA2 position is that capital contributions are excluded from the capital base. Generally, these amounts relate to covered services which do not provide a benefit for all network users.

1080. This consideration is particularly relevant to contributions associated with major transmission augmentations, where contributions are only required when the augmentation does not pass the NFIT. The purpose of the NFIT is to ensure that the broad customer base only pays for augmentations that deliver identifiable net benefits for all customers and hence are efficient from the perspective of all users. The corollary is that contributions may relate to elements of a major augmentation which are deemed not efficient under the NFIT test.

1081. The other end of the contributions spectrum involves the smaller 'user pays' contributions, such as those under Appendix 8 of the Access Code. These range from pillar to post connections through to sub-divisions and supply extension schemes. Here, like the NFIT, the principle of economic efficiency is 'user pays'.

1082. With regard to benefits for other customers, the UDIA submitted that:

- electricity customers benefit from the gifted asset and therefore should contribute to the taxation liability;
- Synergy, Horizon and other wholesale purchasers of electricity from the grid for sale to domestic customers gain from the grid connections that result from the gifted asset;

[282] Government of Western Australia 2004, *Electricity Networks Access Code 2004*, www.slp.wa.com.au, p. 87.

- local governments also gain through uplift in the rates base as the value of a lot that is connected to the grid is higher than a lot that is reliant on its own power.

1083. First, the Authority considers that there is little benefit for other customers from capital contributions, whether these be gifted assets or cash contributions.[283] As these contributions relate to assets which benefit only a small subset of contributing customers, the full costs associated with the related investments should be passed on to those customers. This is no different to the supply of any other good or service in a competitive market, where the relevant tax liabilities are passed on to the specific customer, thereby ensuring that the supplier earns a competitive after tax return on its capital for that particular product.

1084. Second, electricity retailers may benefit from new connections. However, retail businesses would likely pass on such charges to the broad customer base. The great majority of these end-use customers do not gain any benefit from the contribution asset. Therefore, this is not a strong argument for inclusion of capital contributions.

1085. Finally, it is not clear how inclusion of capital contributions would allocate those costs to local governments. Where local governments benefit from grid connected developments, the allocation of costs and benefits is a matter for the local government and the developer.

1086. Overall, given the objective of economic efficiency and the principle of 'user pays', the Authority considers that it is inappropriate to subsidise the costs associated with contributions through transfer to the broader customer base. The Authority considers that to allow costs that originate from a single customer – or that are associated with investments that do not pass the NFIT – to be charged to all customers would be inconsistent with the objectives of the Code.

Capital contributions lead to a tax liability for Western Power

1087. Under tax law, a capital contribution which relates to an asset that meets the required definitions becomes revenue for Western Power in the year of receipt, which is matched to a 'fair value' entry in Western Power's tax asset base (**TAB**).[284]

1088. Western Power then becomes liable for tax at 30 per cent on that revenue in the first year, and for deductions from its tax liabilities in the out-years tax reflecting the depreciation of the TAB contributed asset.

1089. Given that Western Power's tax account is in nominal terms, the net present value (**NPV**) of the stream of future depreciation tax liability deductions is less than the upfront cost of the tax liability. This 'time value of money' is significant, and could

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283 There could be an argument that existing and future customers in some instances may benefit from a contribution which extends the network, thereby creating future options to serve additional new loads. An example might be a major augmentation that initially only benefits one customer, but which may ultimately provide for many future customers. Under the new facilities investment test (**NFIT**), such an asset could be subject to a contribution where the asset was deemed to involve a component which only benefited the contributor. However, as other customers connected and benefited from the contributed asset, the contributor could expect a refund of the contribution. The refund would pass NFIT, and that refund proportion of the asset would be deemed efficient under NFIT and rolled into the regulated asset base. On this basis, it is appropriate to exclude any costs associated with contribution from being passed on to the broader customer base.

284 Australian Accounting Standards Board 2009, *AASB Interpretation 18*, www.aasb.gov.au.

result in a substantial cost for Western Power. It therefore may be reasonable for Western Power to pass this cost on to the developer.

The required contribution could increase by up to 25 per cent

1090. The Authority accepts that a capital contribution could lead to a tax liability for Western Power of 25 per cent of the value of contributed assets.

1091. The Authority considers that rather than customers funding these costs, it would be more appropriate for Western Power to obtain recompense for these costs as part of the commercial negotiations or evaluation of charges related to any contribution.

Disincentive for investment in Western Australia

1092. Western Power suggests that applying costs to the contributor will create a disincentive for investment in Western Australia, which plays an important role in State development. The ENA also was of this view.

1093. However, the Authority considers that the proposed treatment could lead to a distortion in investment incentives, as it could allow costs that are associated with potentially inefficient investments in the network (such as those that do not pass the NFIT) to be charged to all customers. As a result, while it is true that making contributors pay the full costs would reduce *their* returns, it would increase the returns of other customers on the network. As a result, it is not clear that the potential for overall investment in Western Australia would be reduced. If anything, given deadweight losses associated with the distortion, it is possible there could be a net increase in investment in Western Australia, once the distortion is removed.

Estimating tax and associated risks

1094. Western Power suggests that the tax associated with a particular transaction can only be estimated having regard to the entity's overall tax profile, as the estimated tax costs are not directly related to the provision of the capital contributions.

1095. The Authority accepts this point but considers that it provides further support for not including capital contributions in the regulatory tax module. Western Power and the contributor are best placed to work out the tax implications of any contribution, taking into account their business interests and tax positions. Excluding capital contributions delivers an incentive for Western Power to deal with contributions in a commercial manner through negotiation with the contributor.

1096. Western Power also suggests that exclusion leads to associated risks for any attempt to recover tax costs from users. However, the Authority considers that these risks are typical for any commercial enterprise, and that no special consideration should be given to Western Power in relation to these matters.

Other regulators allow inclusion

1097. The Australian Energy Regulator (**AER**) includes capital contributions in the tax asset base.

> Depreciation for tax purposes... is based on the [assessed] tax asset values, capex values and tax asset lives... Capex recognised for tax purposes is net of disposals but includes the value of customer contributions.[285]

1098. The Authority's understanding is that the AER considers the tax implications of capital contributions to be an expense associated with the regulated entity's business.

1099. In a recent Final Decision, IPART chose to include capital contributions.[286]

> Cash and non-cash capital contributions (assets free of charge) *for regulated activities* should be viewed as contributing to regulated revenues and regulated expenses for calculating the regulatory tax liability...

1100. The Authority understands that it is a policy of the New South Wales Government that developers who gift assets or provide capital contributions pay no more than the cost of the capital expenditure.

1101. Despite the position of the AER and IPART, the Authority considers that its analysis does not support the inclusion of capital contributions, as to do so would lead to the broader customer base subsidising Western Power for costs that may potentially be inefficient, or which are caused by individual users. To include capital contributions under these circumstances would be inconsistent with the objectives of the Access Code.

Conclusions with regard to capital contributions

1102. The Authority considers that Western Power has not made a case for the inclusion of capital contributions in the tax building block calculations.

1103. It is the Authority's view that:

- the tax costs associated with capital contributions may not necessarily be associated with efficient costs – as is the case where a contribution is required for an augmentation that does not meet the NFIT;
- to allow tax costs that are not associated with efficient costs to be charged to all customers would be inconsistent with the objectives of the Code;
- Western Power does have a tax liability associated with a contribution, but given the objective of economic efficiency and the associated principal of 'user pays', this should be recovered from the contributor – to do otherwise would lead to a subsidy from the existing customer base to the contributing entity;
- Western Power and the contributor are best placed to work out the commercial terms of the tax implications of any contribution, taking into account their business interests and tax positions;
- the analysis provides support for the Authority taking a different position to that of other regulators.

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285 Australian Energy Regulator 2008, *Electricity distribution network service providers : Post-tax revenue model handbook*, www.aer,gov.au, p. 12.

286 IPART 2011, *The incorporation of company tax in price determinations*, www.ipart.nsw.gov.au, pp. 15 and 16.

1104. Accordingly, the Authority requires that Western Power remove capital contributions from the tax module of the PTRM for the purposes of determining the Target Revenue.

Required Amendment 16

No amounts in relation to tax on capital contributions may be included in Target Revenue.

Return on Working Capital

Access Code Requirements

1105. The Access Code does not explicitly contemplate a return on working capital as a cost.

1106. The objectives for the price control in an access arrangement set out in section 6.4 of the Access Code include the objective of giving the service provider an opportunity to earn an amount of target revenue for the access arrangement period that meets the forward looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

1107. The values of target revenue applying under the price control in the current access arrangement include an allowance for a return on working capital.

1108. For each of the transmission and distribution networks, a cost of working capital for each year of the current access arrangement was determined as the difference between the implicit cost incurred by Western Power by providing credit to users of services and the implicit benefit to Western Power of receiving credit from suppliers.

1109. The requirement for working capital was calculated as the difference between the sum over 45 days of the average daily covered service revenue and the sum over 20 days of the average daily expenses for the year (new facilities investment and non-capital costs). This was based on:

- an assumed revenue lag of 45 days, based on meter reading cycles and payment terms of the electricity transfer access contract; and
- an average expense lead of 20 days on operating and capital expenditure based on:
  - an expense lead of 10 days on labour costs, comprising 18 per cent of costs for the distribution network and 23 per cent of costs for the transmission network;
  - an expense lead of 30 days on direct costs of materials and services, comprising 35 per cent of costs for the distribution network and 63 per cent of costs for the transmission network; and
  - no expense lead on internal costs of materials and services or other costs.

1110. The cost of working capital was calculated as the value of working capital at the beginning of each year of the access arrangement period multiplied by the approved pre-tax WACC.

Proposed Revisions

1111. In the proposed revisions to the access arrangement, Western Power proposed an allowance for a return on working capital in line with the current access arrangement.[287] The proposed costs of working capital (as submitted in September 2011) are indicated in Table 128 and Table 129.

Table 128 Proposed Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	489.441	519.740	553.323	593.982	655.437
Expenses					
Forecast new facilities investment	352.483	275.872	358.297	523.437	407.650
Forecast non-capital costs	124.996	122.482	132.336	142.406	156.340
Total expenses	477.479	398.353	490.632	665.843	563.990
Working capital requirement					
Receivables (45 days)	60.342	64.077	68.218	73.031	80.807
Creditors (20 days)	-26.163	-21.828	-26.884	-36.385	-30.904
Working capital requirement	34.179	42.250	41.334	36.646	49.904
Return on working capital at WACC = 8.82%	**1.215**	**3.015**	**3.726**	**3.646**	**3.232**

Table 129 Proposed Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	1,127.756	1,192.511	1,274.111	1,327.441	1,403.210
Expenses					
Forecast new facilities investment	567.444	650.671	665.611	635.625	642.746
Forecast non-capital costs	371.361	387.391	408.266	420.133	447.854
Total expenses	938.804	1,038.062	1,073.878	1,055.758	1,090.600
Working capital requirement					
Receivables (45 days)	139.038	147.022	157.082	163.210	172.998
Creditors (20 days)	-51.441	-56.880	-58.843	-57.692	-59.759
Working capital requirement	87.597	90.142	98.240	105.518	113.240
Return on working capital at WACC = 8.82%	**5.125**	**7.726**	**7.951**	**8.665**	**9.307**

1112. Western Power used the same working capital cycle assumptions as those in the current access arrangement of 45 days for receivables, determined from the meter reading cycles and payment terms of the electricity transfer access contract, and

[287] Revised access arrangement information, Section 12.3, pp. 281-282.

20 days for creditors, determined from an expense lead of 10 days on labour costs and an expense lead of 30 days on direct costs of materials and services.

Considerations of the Authority

1113. "Working capital" refers to a stock of funds that must be maintained by a service provider to pay costs as they fall due. In circumstances where it is the norm for the costs of providing services to be incurred before the revenues from provision of services are received, a stock of working capital may need to be derived from a capital investment in the business. The cost of this stock of working capital (the required return on the capital investment) is a cost to the service provider of operating its business and providing services.

1114. The working capital provided for should only reflect the essential items for the conduct of the service provider's business.

Current and Past Application to Western Power

1115. In determining proposed allowances for working capital, Western Power has determined a "stock" of working capital that is varied from year to year according to the costs and revenues for each year and assumptions of time periods of credit made available to Western Power by suppliers and credit made available by Western Power to network users. The cost of working capital is determined as a return on the funds invested in the stock of working capital in the same manner as funds invested in the physical assets (capital base) of the network. This has been done in a manner consistent with the allowance for working capital during AA2.

1116. While the Authority considered that an allowance for the cost of working capital could reasonably be included in the cost of service during AA2, it noted in its Final Decision and Further Final Decision for AA2 that it was "… aware that regulators in other Australian jurisdictions have questioned whether an allowance for costs of working capital can reasonably be included in the determination of regulated revenues for utility businesses." [288] [289] It also indicated its intention to give the matter further consideration.

Recent Regulatory Practice

1117. The AER does not allow for a return on working capital in its Post Tax Revenue Model (**PTRM**). The reason for this is that it considers the PTRM already over-compensates service providers in relation to cashflow timing assumptions. The original basis for this view was a report commissioned by the ACCC in 2002 in relation to working capital for transmission companies.[290] The report endorsed the concept of a timing adjustment being required for the lag in the recovery of operating expenses but also considered the wider issue of all intra-year timing assumptions inherent in the ACCC's total revenue requirement formula. The formula was deemed to over-compensate for intra-year timing in relation to capital costs, by an amount that is likely to exceed the

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[288] 4 December 2009, ERA, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network, p. 252.

[289] 19 January 2010, ERA, Further Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network, p. 49.

[290] November 2007, AER, Issues Paper: Guidelines, models and schemes for electricity distribution network service providers, p. 11.

under-compensation for working capital based on operating costs. The report proposed that an allowance should not be included for working capital in order to balance out the discrepancy.

1118. Since this work was carried out, the AER has made an adjustment to its cash flow timing assumptions by allowing for mid-year timing in capital expenditure in its PTRM. This amendment further increases the over-compensation already identified.

1119. Prior to the AER taking on responsibility for electricity distribution pricing determinations, a mixed approach was taken by the State regulators. The Victorian Essential Service Commission and QCA both took the same approach as the ACCC and rejected allowances for a return on working capital in electricity distribution regulation on the grounds that the service providers are already over-compensated with respect to cash-flow modelling timing. However, IPART and ESCOSA did provide a separate allowance for a return on working capital. IPART took the view that the return fixed assets allowed in the pricing decision was just sufficient to cover these costs and that a separate amount should be made available for working capital. ESCOSA considered "it appropriate to provide an allowance in respect of the cost of financing the operating activities, notwithstanding the over-compensation provided with respect to capital activities.[291] However, ESCOSA did not provide an allowance for working capital for capital activities.

1120. The AER is now responsible for all electricity distribution pricing determinations and has adopted the PTRM for determining target revenue. As noted in paragraph 1117 above, the PTRM does not allow a separate return on working capital on the basis that it already over-compensates service providers in relation to cash flow timing assumptions.

1121. The formula the Authority determined in the Draft Decision for setting Western Power's target revenue is essentially the same as that used by the AER, with the exception of the mid-year timing assumption for capital expenditure. However, as noted above, the mid-year timing assumption only serves to increase the over compensation.

1122. Prior to the Draft Decision, the Authority attempted to demonstrate the over-compensation empirically using the cash flow assumptions Western Power provided with its working capital analysis. However, initial results at the time of the Draft Decision suggested that, in the case of Western Power, there may not be such an over-compensation. The Authority has updated its analysis for the Final Decision and found similar results. Reasons why the position appears to be different from that found by the AER may include:

- differences in the proportions of components of target revenue (e.g. operating expenditure, depreciation or return on the capital base) compared with other service providers;
- specific items such as the TEC and recovery of deferred revenue, which are not common to other service providers; and
- differences in cash flow timing assumptions compared with other service providers.

291 ESCOSA, 2005-2010 Electricity Distribution Price Determination – Part A – Statement of Reasons, pp. 122-124.

Other factors that reduce the need for a return on working capital

1123. Notwithstanding the results of the Authority's cashflow analysis, the Authority has identified a number of items that provide a benefit to Western Power.

1124. Western Power's calculation of working capital ignores the cash contribution payments made to Western Power. Under Western Power's capital contributions policy, these payments must be made to Western Power either up-front or on a periodic basis with interest charged. The amount received by Western Power would be in advance (and in some cases it could be considerably in advance), of the required expenditure to build the asset. This could provide a significant benefit to Western Power considering that it has forecast to receive $636 million for transmission and distribution for cash contributions during AA3. This is equivalent to 10.6 per cent of transmission and distribution new facilities investment during the period.

1125. In the current access arrangement, Western Power significantly under-spent in operating expenditure and capital expenditure, resulting in Western Power receiving a return on working capital above what was actually required. As there is no adjustment mechanism to take account of this, Western Power retains the benefit.

Working capital assumptions

1126. The Authority noted in the Draft Decision that Western Power had not demonstrated that its proposed working capital forecasts were efficient as it had determined its working capital requirements based on historic assumptions. The Authority considered each of the assumptions below.

Debtors

1127. The Authority noted that Western Power's assumption for debtor days is in line with its current meter reading cycles and the invoicing and payment terms in the electricity transfer access contract. The majority of meters are read on a bi-monthly basis with the remainder read on a monthly basis. The standard terms of the electricity transfer access contract are that an invoice is raised within 14 business days of the month following the meter read and the user is required to pay within 10 business days.

1128. However, the Authority notes that Western Power's largest customer, Synergy, endeavours to invoice customers within a few days of the meter being read and requires payment within three weeks of the bill being sent.

Creditors

1129. Western Power based its creditors' payment terms on 10 days for manpower costs, 30 days for other costs, and 0 days for internal costs. In the Draft Decision the Authority modified the calculation of creditor days to reflect the Draft Decision amendment to include inventory in working capital rather than the capital base. The recalculated creditor days were 25 days for transmission and 28.5 days for distribution.

Inventory

1130. As discussed in paragraphs 663 to 667, Western Power proposed to include inventory in the capital base. However, the Authority's Draft Decision considered it was clearer and more transparent to consider inventory as part of working capital requirements.

1131. Western Power provided analysis in Appendix D of the access arrangement information, which it considered demonstrated the efficiency of its forecast level of inventory. Western Power provided two tables in its analysis, one that compared inventory value to works program size and one that compared inventory value to network size by state.

1132. As Western Power only provided aggregate information for each state, the Authority was not able to verify the analysis provided. However, the Australian averages against which Western Power compared itself were based on simple averages, which the Authority considered did not provide a valid comparison. The Authority performed its own comparison using a weighted average excluding Western Power.

1133. On this basis Western Power's performance was worse than the average for other states and worse than all states with the exceptions of Tasmania for both measures and Queensland for inventory value to network size.

1134. For the purposes of the Draft Decision, the Authority used the average level of inventory value to works program size for other Australian service providers to estimate an efficient level of inventory for Western Power. Based on the information provided in Western Power's Appendix D, the Authority calculated this to be 4 per cent.

Draft Decision

1135. In the Draft Decision the Authority considered that working capital was a legitimate business cost but due consideration should be given to the over-compensation, identified by the AER and others, provided in financial models used by regulators to calculate the total revenue requirement and other factors such as the benefit of receiving capital contributions in advance of expenditure. For the purposes of the Draft Decision, the Authority included an allowance for working capital with a number of amendments to Western Power's proposal.

1136. The gross cost of service, expenses and return on working capital were amended to reflect the Authority's required amendments elsewhere in the Draft Decision.

Table 130 Draft Decision Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	297.8	311.8	331.9	343.8	358.3
Expenses					
Forecast capital expenditure	275.0	353.1	200.6	225.2	274.4
Forecast operating costs	100.1	99.2	100.9	103.6	107.5
Total expenses	375.1	452.3	301.5	328.8	381.9
Working capital requirement					
Receivables (45 days)	36.7	38.4	40.9	42.3	44.2
Creditors (28.5 days)	(20.6)	(24.8)	(16.5)	(18.0)	(20.9)
Inventory (4% of capital expenditure)	11.0	14.1	8.0	9.0	11.0
Working capital requirement	27.2	27.8	32.4	33.3	34.2
Return on working capital at WACC = 3.87%	**0.5**	**1.1**	**1.1**	**1.3**	**1.3**
Western Power Proposal	1.2	3.0	3.7	3.6	3.2

1137.

Table 131 Draft Decision Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	945.7	974.6	1,015.6	1,030.1	1,066.2
Expenses					
Forecast capital expenditure	515.9	586.6	590.1	557.9	559.8
Forecast operating costs	330.0	331.9	337.4	335.1	346.0
Total expenses	845.9	918.5	927.5	893.1	905.9
Working capital requirement					
Receivables (45 days)	94.3	97.9	102.9	104.3	108.9
Creditors (25 days)	(46.3)	(50.3)	(50.8)	(48.8)	(49.6)
Inventory (4% of capital expenditure)	20.6	23.5	23.6	22.3	22.4
Working capital requirement	68.5	71.0	75.7	77.8	81.7
Return on working capital at WACC =3.87%	**2.3**	**5.7**	**2.8**	**2.9**	**3.0**
Western Power Proposal	5.1	7.7	8.0	8.7	9.3

1138. The Draft Decision required the following amendment.

Draft Decision Amendment 22

The amounts included in target revenue for working capital must be amended to the values in Table 71 and Table 72.

1139. In response to the Draft Decision, Western Power has not accepted Draft Decision Amendment 22 and notes in the amended access arrangement information that it has amended its working capital requirements to reflect:

- the post-tax method of determining the cost of service;
- the updated operating and capital expenditure forecasts for the AA3 period;
- an updated estimate of creditor days;
- the inclusion of the inventory forecast within working capital.

1140. A summary of Western Power's revised forecast of working capital is set out in Table 132 and Table 133 below.

Table 132 Western Power's Revised Proposed Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	426.8	449.3	480.2	509.2	546.8
Expenses					
Forecast new facilities investment	303.0	368.4	264.4	390.4	477.7
Forecast non-capital costs	125.5	124.7	129.7	140.6	153.1
Total expenses	428.5	493.2	394.1	531.0	630.9
Working capital requirement					
Receivables (45 days)	52.6	55.4	59.2	62.6	67.4
Creditors (16 days)	-18.7	-21.6	-17.2	-23.2	-27.6
Inventory	20.0	28.5	31.4	28.9	30.7
Working capital requirement	53.8	62.3	73.3	68.3	70.5
Return on working capital at WACC = 6.39%	**0.870**	**3.442**	**3.981**	**4.686**	**4.370**

Table 133 Western Power's Revised Proposed Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	996.6	1,074.7	1,162.5	1,242.1	1,348.5
Expenses					
Forecast new facilities investment	634.1	679.6	688.1	676.9	677.1
Forecast non-capital costs	386.6	401.0	409.6	415.8	433.0
Total expenses	1,020.6	1,080.7	1,097.7	1,092.7	1,110.1
Working capital requirement					
Receivables (45 days)	122.8	132.5	143.3	152.7	166.2
Creditors (15.5 days)	-43.3	-45.8	-46.6	-46.2	-47.1
Inventory	58.2	66.2	66.7	62.1	58.3
Working capital requirement	137.7	152.8	163.4	168.6	177.4
Return on working capital at WACC = 6.39%	**3.668**	**8.802**	**9.767**	**10.447**	**10.774**

1141. The Authority has reviewed Western Power's revised forecast and has found the following:

- The forecast receivables balance has been calculated using the unsmoothed gross cost of service. However, the annual profile of gross cost of service is smoothed over the five years before setting the amount of target revenue which can be billed each year. The forecast receivables balance should be calculated from the smoothed revenue requirement and must be consistent with the target revenue approved by the Authority in the Final Decision.

- The Authority has been unable to reconcile Western Power's forecast new facilities investment and non-capital costs with the forecasts included elsewhere in Western Power's amended access arrangement information. In any case, these forecasts must be amended to be consistent with the forecasts approved by the Authority in this Final Decision.

- Western Power has adopted the same creditor working days assumptions as used in its proposed revisions to the access arrangement (i.e. 10 days for labour, 30 days for materials and nil for other costs) but has revised the weightings used to calculate the overall average creditor days. Western Power states the weightings for transmission are 56 per cent for labour, 35 per cent for materials and 9 per cent for indirect costs. Western Power's weightings for distribution are 56 per cent for labour, 32 per cent for material and 11 per cent for indirect costs. Based on information provided by Western Power in relation to price escalation, the Authority considers these weightings include an element for contract labour. For the purposes of working capital, only wages directly paid by Western Power in its payroll should be included. Western Power's 2011 Annual Report shows that employee-related costs comprise 29 per cent, and materials comprise 66 per cent, of total expenses excluding depreciation and borrowing costs.[292] The Authority has based its assessment of creditor days on these proportions. For indirect costs (which includes items such as rates and insurance), the Authority has assumed a 30 day creditor period. This results in average creditor days of 24.2.

- Western Power has not included any new evidence to support its assessment of the level of inventory required. Western Power asserts that the Authority's technical consultant considers Western Power's methodology forecasts an efficient value of inventory. However, the Authority notes that its technical consultant stated it was unable to comment on the efficiency of the proposed asset turnover ratio used by Western Power.[293] Consequently, the Authority has maintained its position taken in the Draft Decision and used the average level of inventory value to works program size for other Australian service providers to estimate an efficient level of inventory for Western Power. Based on the information provided in Western Power's Appendix D in the access arrangement information, the Authority calculated this to be four per cent.

- Western Power has based the return on working capital on its assessment of WACC. The Authority has determined a different WACC in this Final Decision and the return on working capital must be amended to be consistent with the Final Decision.

1142. As noted in paragraph 1125 above, during the current access arrangement, Western Power significantly under-spent in operating expenditure and capital expenditure, resulting in Western Power receiving a return on working capital above what was actually required. As there is no adjustment mechanism to take account of this, Western Power retains the benefit. The Authority has considered whether an adjustment mechanism should be introduced to take account of this. However, as the amount of potential overcompensation would be small, on balance, the Authority has decided not to pursue this matter further in this decision.

1143. The Authority has recalculated the return on working capital, after adjusting for the matters noted above. The amended values are set out in Table 134 and Table 135 below.

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292 Western Power Annual Report 2011 p. 77.

293 Geoff Brown and Associates, Technical Review of Western Power's Proposed Access Arrangement for 2012-17, 27 March 2012, p. 65.

Table 134 Final Decision Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	323.5	323.3	332.8	341.9	357.2
Expenses					
Forecast capital expenditure	295.6	385.6	240.1	262.8	347.5
Forecast operating costs	103.7	102.7	103.1	105.2	107.7
Total expenses	399.3	488.4	343.2	368.0	455.3
Working capital requirement					
Receivables (45 days)	50.3	42.8	38.8	35.4	32.3
Creditors (24.2 days)	-26.5	-32.4	-22.8	-24.3	-30.2
Inventory (4% of capital expenditure)	11.8	15.4	9.6	10.5	13.9
Working capital requirement	35.6	25.8	25.7	21.6	15.9
Return on working capital at WACC = 3.6%	**0.5**	**1.3**	**0.9**	**0.9**	**0.8**
Western Power Revised Proposal	0.870	3.442	3.981	4.686	4.370

Table 135 Final Decision Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	935.8	898.9	1,021.9	1,030.3	1,064.5
Expenses					
Forecast capital expenditure	586.8	657.9	656.9	626.3	627.1
Forecast operating costs	347.8	350.9	347.0	342.6	351.6
Total expenses	934.6	1,008.9	1,003.9	968.9	978.6
Working capital requirement					
Receivables (45 days)	110.9	118.2	123.9	131.9	141.1
Creditors (24.2 days)	-61.9	-66.9	-66.6	-64.1	-64.9
Inventory (4% of capital expenditure)	23.5	26.3	26.3	25.1	25.1
Working capital requirement	72.4	77.7	83.7	92.9	101.3
Return on working capital at WACC =3.6%	**2.1**	**2.6**	**2.8**	**3.0**	**3.3**
Western Power Revised Proposal	3.668	8.802	9.767	10.447	10.774

Required Amendment 17

The amounts included in target revenue for working capital must be amended to the values in Table 137 and Table 138.

Tax liabilities

Access Code Requirements

1144. Section 6.65 of the Access Code states that the Authority may from time to time make and publish a determination of the preferred method for calculating the WACC in access arrangements.[294,295]

1145. The Code states at Section 6.4 that:

> The price control in an access arrangement must have the objectives of:
>
> a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

1146. Tax liabilities in the current access arrangement were incorporated as an adjustment within the real pre-tax WACC.

Proposed revisions

1147. No revisions to the incorporation of tax liabilities within the pre-tax real WACC were proposed by Western Power in its September 2011 revisions for the third access arrangement.

Considerations of the Authority

1148. In regulating electricity networks in Western Australia, the Authority determines a revenue requirement that is sufficient to cover the service provider's efficient costs of service. The key elements contributing to the estimated regulated cost of service include depreciation of the regulated capital base, a return on the regulated capital base, the operating costs, and the tax liabilities.

1149. As set out below in paragraphs 1301 to 1317 the Authority decided to adopt a post-tax real WACC for the Draft Decision.

1150. With a post-tax approach, tax liabilities are modelled separately – as a building block within the revenue modelling framework. For the Draft Decision, the Authority modelled Western Power's tax liabilities in this way, in order to determine the revenue requirement for AA3.

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294 Western Australian Government Gazette 2011, *Electricity Networks Access Code 2004*, Clause 6.65, p. 90.

295 On 22 April 2010 the Authority issued a notice advising that its preferred Weighted Average Cost of Capital Methodology, published on 25 February 2005, had expired and hence no longer applied to covered electricity networks under the Access Code.

1151. To this end, the Authority in the Draft Decision:

- calculated a set of taxation accounts that were derived from the regulatory accounts:
  - the nominal opening value of the tax asset base (**TAB**) for AA3 was derived from the closing nominal value of the regulatory asset base (**RAB**) for 2011-12;
  - expenditure on new assets was brought into TAB at the estimated nominal value in the year of expenditure;
  - any deductions for redundant assets were brought into the TAB at the estimated nominal value in the year of redundancy;
  - a set of taxation accounts was calculated for the transmission business alone, as well as for the whole business;
  - the difference between the amount of tax calculated in the combined tax accounts and the amount of tax calculated in the tax accounts for the transmission business alone was attributed to the cost of service for the distribution business; and
- maintained the debt at 60 per cent of the estimated TAB:
  - calculated the annual interest deductions for taxation purposes from the resulting closing value of the debt account;
  - based the interest rate deduction on a nominal cost of debt that was consistent with the WACC calculation;
- incorporated the cost of raising equity as a cash flow, but did not assume any tax deductions;[296]
- carried any estimated tax losses forward;
- depreciated assets in the tax base utilising the prime cost method.

1152. The resulting estimated real tax liabilities contributed to the maximum annual revenue requirement for the transmission and distribution businesses.

1153. To give effect to its reasoning, the Authority required the following amendment to the proposed revised access arrangement:

Draft Decision Amendment 23

The Authority requires that Western Power model its tax liabilities explicitly, as a separate nominal 'building block', applying the method set out in the Draft Decision.

To this end, the Authority requires that Western Power amend the tax liabilities for the purposes of determining its maximum annual revenue requirements to those estimated by the Authority.

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296 Certain parts of the equity raising transactions costs may be deductible for tax purposes in the year of the equity raising – including legal fees, accountant's fees and prospectus costs. However, the Authority considered that these costs are small and hence could be ignored for the purposes of the revenue modelling (see Appendix 5 of the Draft Decision: Economic Regulation Authority 2012, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 424).

1154. In response to the Draft Decision Western Power:

- accepted the application of a post-revenue model (**PTRM**); but
- did not accept the Authority's approach to estimating tax liabilities based on a TAB that was derived from the regulatory accounts.

1155. Western Power instead proposed to estimate tax liabilities based on a set of taxation accounts that were derived from its tax asset register. The resulting opening value of the TAB at 30 June 2012 was derived from estimates developed by Ernst & Young that reflected:[297]

- Western Power's fixed asset register as at 1 April 2006, including all contributed and gifted assets
- additions and disposals for 1 April 2006 – 30 June 2006 and the financial years 2006/07, 2007/08, 2008/09, 2009/10, 2010/11 and 2011/12, including all contributed and gifted assets
- depreciation based on effective lives for depreciation purposes using the prime cost method.

1156. Given that the resulting TAB reflects Western Power's actual tax asset register, the depreciation rates are based on the Australian Taxation Office's (**ATO**) effective lives for the relevant asset classes.

1157. Consistent with the ATO approach, in arriving at its estimates Western Power excluded from the TAB:[298]

- capital works in progress to 28 February 2012 and estimated capital expenditure from March to June 2012; and
- land.

1158. Western Power also excluded assets that are not included in the RAB, as they either relate to non-reference services, or have been disallowed:[299]

- IMO-related system management assets and unregulated assets;
- an estimate of the tax written down value of assets which were previously excluded from Western Power's RAB balance.

1159. For the third access arrangement period, Western Power proposed rolling forward the value of the TAB by:[300]

- adding all capital expenditure (including contributed and gifted asset) on an as incurred basis

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297 Western Power 2012, Amended access arrangement information for the Western Power Network, www.erawa.com.au, p. 173.

298 Western Power 2012, Amended access arrangement information for the Western Power Network, www.erawa.com.au, Appendix P, p. 9.

299 Ernst & Young 2012, *Tax asset base for regulated revenue purposes: Electricity Networks Corporation Trading as Western Power*, July, p. 10.

300 Western Power 2012, Amended access arrangement information for the Western Power Network, www.erawa.com.au, p. 173.

- deducting the depreciation based on the applicable effective tax lives calculated on a straight-line basis.

1160. The Authority has considered Western Power's proposal to use its tax asset register for the purpose of developing the TAB.

1161. In principle, the Authority would not object to Western Power utilising its proposed TAB, provided that capital contributions were appropriately removed in line with the requirement set out in the Draft Decision.

1162. However, a major issue arises in that Western Power's proposed TAB includes the value of capital contributions. The Authority in the Draft Decision required that capital contributions be removed from the TAB, and has confirmed this requirement in this Final Decision.

1163. That said, the Authority considers that only those capital contributions since 1 July 2009 would need to be removed from Western Power's estimates, in order to calculate an acceptable opening value of the TAB. This is because capital contributions were included in the RAB up until this point in time:

- For pre 1 July 2009 capital contribution assets, inclusion of capital contributions in the RAB meant that customers effectively paid Western Power an allowance for the tax liability in the first year of an asset's life. Customers then received a tax depreciation deduction over the remainder of the asset's life, partially offsetting the initial tax allowance. Retaining the value of these capital contributions in the TAB would ensure that the depreciation deductions, against the original tax allowance, continue to be paid through to the end of the asset's effective life.
- After 1 July 2009, capital contribution assets were excluded from the RAB. Excluding these assets from the TAB would achieve alignment of the TAB with the RAB. Since 1 July 2009, Western Power's target revenue has not included any amounts in relation to contributions and therefore should not be subject to any tax deductions in relation to those assets.

1164. There would also be a requirement to remove capital contributions from the forecast capital expenditure in the TAB over the third access arrangement period.

1165. To this end, the Authority on 10 July 2012 requested that Western Power provide it with a TAB for the transmission and distribution businesses that excluded capital contributions. In response, Western Power provided an aggregated estimate of the TAB, as at 1 July 2012, for each of the transmission and distribution business, derived from work by Ernst & Young. Ernst & Young noted in its report that it based its estimates on information provided by Western Power at an aggregated level:[301]

> The information [Ernst & Young] received in respect of asset contributions is grouped into broad asset categories and no detailed information is available to identify the specific underlying assets acquired. The description for each of these broad asset categories is representative of the underlying assets...

[301] Ernst & Young 2012, *Tax asset base for regulated revenue purposes: Electricity Networks Corporation Trading as Western Power*, July, p. 7.

1166. Ernst & Young made a number of assumptions in order to derive the capital contributions in each asset category:[302]

> [Ernst & Young] used the percentage splits provided by the revenue modelling contribution information to allocate the contributions to a depreciable asset ERA category...
>
> In order to do notional depreciation estimations for contributed assets acquired after 1 July 2004, [Ernst & Young] assumed that the assets were installed and ready for use on 1 January (i.e. mid-year) in the same financial year as the contributions were recorded as revenue in the relevant financial report.

1167. Ernst & Young noted some inconsistencies between the resulting financial reporting estimates derived from the tax asset register and those derived from the RAB revenue modelling. This may be due to timing differences between the two approaches:[303]

> ...[Ernst & Young] note the following:
>
> - There was a difference between the revenue modelling contributions revenue and the audit financial report contributions revenue of $78.75m (for the years ended 30 June 2005 to 30 June 2012), where the revenue modelling revenue exceeded the audited revenue.
> - [Ernst & Young] consider that the financial reporting information is a reliable quantification of the amount of contributions revenue over this period, as this information has been audited.
> - Although the accounting policies used during the whole period are not clear, it is likely that the time of recognition of the contributions revenue for accounting purposes is more aligned to the relevant tax depreciation start time.
> - The ERA has previously accepted the split of contributions revenue between the distribution and transmission businesses and between the various ERA asset categories within these businesses.

1168. Western Power did not report on the implications of removing capital contributions for the forecast tax depreciation during third access arrangement. However, Ernst & Young stated that:[304]

> In [Ernst & Young's] opinion, if contributed assets are excluded from the starting base and contributions received are not included in assessable income for post-tax revenue modelling purposes, then contributed assets should also be excluded from the tax depreciable additions during the AA3 period.

1169. The Authority subsequently asked Western Power to provide, as a minimum:[305]

- the underpinning Ernst & Young spreadsheet calculations of the taxable asset base opening values (excluding capital contributions, in each of the transmission and distribution businesses), by ERA asset sub-category;

302 Ernst & Young 2012, *Tax asset base for regulated revenue purposes: Electricity Networks Corporation Trading as Western Power*, July, p. 11.

303 Ernst & Young 2012, *Tax asset base for regulated revenue purposes: Electricity Networks Corporation Trading as Western Power*, July, p. 12.

304 Ernst & Young 2012, *Tax asset base for regulated revenue purposes: Electricity Networks Corporation Trading as Western Power*, July, p. 15.

305 Economic Regulation Authority 2012, Final Decision Question 14 (FD14).

- any resulting change in the assumed average effective lives of assets, for each ERA asset sub-category, that may arise due to the removal of the capital contributions (or alternatively, a statement that this change is not significant or cannot be estimated); and

- any resulting change in the average remaining asset lives at 1 July 2009 and 1 July 2012, for each ERA asset sub-category (or alternatively, a statement that this change is not significant or cannot be estimated).

1170. In response, Western Power provided the Ernst & Young spreadsheets used to estimate the value of capital contributions.[306] In its response, Western Power noted that Ernst & Young had estimated the value of contributions as at 30 June 2012, and the corresponding TAB excluding capital contributions, but that:[307]

> We have not estimated the tax asset base as at 30 June 2009.
>
> We can make no comment on the effective life or average remaining life on the removal of the contribution amounts from the tax asset base.

1171. The Authority has assessed the information provided by Western Power, and considers that it is not reasonable to adopt its proposed TAB for developing the tax liabilities in the PTRM, as capital contributions are included. Based on the information provided by Western Power, it does not appear feasible to remove capital contributions from the proposed TAB, without significant uncertainty with regard to future depreciation rates, which would call into question the utility of such an approach.

1172. While post 30 June 2009 capital contribution assets have been identified, Western Power appears unable to ascertain the effect the removal of these assets would have on the average lives of the (non-contributed) assets remaining in the TAB (as set out at paragraph 1170 above).

1173. Second, there is an issue around the timing of capital work in progress. Specifically, Ernst & Young assumes that the contribution assets are installed and ready for use as at 1 January in the middle of each financial year (as noted at paragraph 1166 above). This reflects ATO practice that assets may only be included in the tax asset register on an 'as commissioned' basis.

1174. However, the RAB includes assets on an 'as incurred' expenditure basis. This sets up a timing difference between the two asset bases. This is likely to create further issues for any efforts to determine the average remaining lives of the assets in each TAB category, as it means that the capital expenditure estimates in the RAB are not determined on the same timing basis as the proposed TAB. This would further complicate any effort to use the forecast RAB capital expenditure to estimate the impact of removing contributions on effective lives in the Western Power TAB.

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306 It is worth noting here that these spreadsheets included values for Ernst & Young's estimated TAB depreciation over AA3 (although not the average remaining asset lives in each TAB category). This material was 'hard wired' into Western Power's proposed revenue model. Ernst & Young stated that it had addressed the tax depreciation relating to the income tax calculations over AA3 in a 'separate report', but this was not included by Western Power in its amended access arrangement information (Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, Appendix P, p. 17).

307 Western Power 2012, *Response to question FD14,* August.

1175. The Authority therefore prefers to retain a TAB for the purposes of the PTRM that is derived from the RAB, as it required in the Draft Decision. The Authority considers that the resulting RAB based TAB:

- excludes post 30 June 2009 capital contributions on a consistent basis;
- is transparent with regard to the effect on remaining average lives and the resulting implications for taxation depreciation;
- provides a consistent treatment of forecast TAB depreciation.

1176. The Authority notes that the main difference between an 'adjusted' Western Power TAB (that accurately excluded capital contributions) and the Authority's RAB based TAB would be due to the effective asset lives assumed in each case. With this in mind, the Authority notes that the RAB based TAB would be expected to have a higher initial opening value, compared to the adjusted Western Power TAB, due to the assumed longer life of assets in the RAB and the resulting slower annual rates of depreciation.[308]

1177. Based on the information provided by Western Power, this would seem to be the case (Table 136). In Table 136:

- Column B takes the opening value of the RAB based TAB on 1 July 2012 (the number in brackets) and removes the value of land and Ernst & Young's estimate of 2012 capital work in progress (**CWIP**).
- Column C provides the Authority's estimates of the Western Power TAB (which is set out in the Column A), and adjusts this to remove the post 30 June 2009 capital contributions, based on the estimates developed by Ernst & Young.
- These adjustments bring Column B and C values to a consistent basis – that is, both columns exclude post 30 June 2009 capital contributions, the value of land, and the value of 2012 CWIP.

1178. Comparing Column B and C in Table 136, it is apparent that the Authority's RAB based TAB estimate is marginally higher than Western Power's TAB. As noted, this would reflect the generally faster ATO depreciation rates, as compared to those applying to the RAB. However, the differences are small.

1179. Further, the impact of the higher initial RAB based TAB increasing the tax depreciation shield would be offset to a degree by the associated smaller depreciation rate in each year of the access arrangement, given that the RAB based TAB has longer assumed lives, and hence smaller annual depreciation rates under the straight line method. This effect would serve to attenuate further any remaining differences between the two approaches.

[308] One significant exception is that for distribution network wooden pole lines. In this case, the ATO effective life is 45 years, whereas the RAB effective life if 41 years. This category comprised just under 30 per cent of all distribution RAB assets at 30 June 2012.

Table 136 Estimates of the opening TAB at 1 July 2012

	Western Power amended proposed revisions (tax asset register TAB with cap. cons. included) ($m 2011/12) (A)	ERA RAB based estimate (excludes cap. cons from 1 January 2009) ($m 2011/12) (B)	Western Power estimated tax asset register TAB with estimated post 30 June 2009 cap cons. excluded ($m 2011/12) (C)
Transmission ICB (numbers in brackets include CWIP and land)	$1,817 ($2,289)	$1,739 ($2,601)	$1,718
Distribution ICB (numbers in brackets include CWIP and land)	$3,866 ($4,291)	$3,443 ($3,867)	$3,429
Total (numbers in brackets include CWIP and land)	$5,683 ($6,580)	$5,182 ($6,467)	$5,148

Note: The final column of post 2009 capital contributions excluded has been estimated by the Secretariat based on Western Power's data. CWIP is 'cost of works in progress'.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au; Authority analysis, Western Power 2012, Response to question FD14, www.erawa.com.au.

1180. In conclusion, the Authority considers that the RAB based TAB will provide appropriate estimates of the tax depreciation shield for the PTRM tax module, which should be reasonably consistent with any estimate appropriately derived from Western Power's tax asset register. The Authority further considers that any approach to remove capital contributions from Western Power's proposed TAB is likely to be complex. This potentially could lead to greater inaccuracies in any estimate of tax liabilities, as compared to the RAB based TAB approach. For these reasons, the Authority requires that Western Power adopt the RAB based TAB.

Required Amendment 18

The Authority requires that Western Power adopt a tax asset base derived from the regulatory accounts for the purposes of determining its forecast tax liabilities and its maximum annual revenue requirement.

Costs of raising equity

Access Code Requirements

1181. The Access Code states at Section 6.4 that:

> The price control in an access arrangement must have the objectives of:
>
> a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

1182. Equity raising costs were not included as part of the current access arrangement.

Proposed revisions

1183. Western Power in its proposed revisions to the access arrangement (September 2011) did not include equity raising costs in the proposed opening capital base at 1 July 2012.

1184. However, in line with Section 6.4 (a)(i) of the Code, Western Power proposed to include direct costs of raising equity incurred during the third access arrangement period:[309]

> We have applied the method for cash flow modelling used by the AER in its recent *Final Decision for Victorian Distributors (2010)* to calculate whether equity raising costs are required for AA3.
>
> Equity raising costs can be classed into two categories: indirect and direct. Direct costs include underwriting, management fees and out of pocket expenses. Indirect costs can include underpricing, where the new equity security is sold at a discount to current market prices. We consider that only direct equity raising costs are relevant to calculating target revenue.
>
> In our modelling, 30% of dividends are assumed to be returned to the business through a dividend reinvestment plan at a cost of 1%. Any further requirement for equity is assumed to come from seasoned equity offerings at a cost of 3%. These assumptions are consistent with the AER's methodology. In keeping with the Australian Competition Tribunal's April 2011 Decision on the value of imputation credits, a distribution rate of 70% is assumed for imputation credits. We have determined that no equity raising costs would be incurred on the basis of these proposed revisions.

Submissions

1185. No submissions other than those from Western Power addressed this topic.

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309 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 246.

Considerations of the Authority

1186. The Authority agreed in its Draft Decision that the efficient costs of raising equity may constitute part of the forward-looking costs of providing covered services.

1187. The Authority considered that the equity share should be maintained at 40 per cent of the estimated asset base, assumed that:

- dividends are paid at a benchmark payout ratio of 70 per cent of after-tax profits – consistent with the Authority's WACC analysis;
- retained earnings of 30 per cent of after-tax profits are available at zero cost;
- 25 per cent of dividends are treated as being reinvested through Dividend Reinvestment Plans (**DRP**) on a 'tick the box' basis, with a zero cost of raising equity applied to these funds;[310] and
- any further required equity is raised at the Seasoned Equity Offering cost of 3 per cent – with these costs added to the asset base and depreciated over the life of the assets.

1188. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 24

The Authority requires that Western Power determine the forward looking efficient costs of raising equity according to the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the cost of raising equity for the purposes of determining the revenue requirement to those estimated by the Authority as set out in Table 66 of the Draft Decision and in Appendix 5.

1189. Western Power in its revised proposed revisions to the access arrangement accepted the Authority's Draft Decision determination on the costs of raising equity, with the exception of the costs associated with DRP. Specifically, Western Power states that:[311]

> In its September 2011 submission, Western Power proposed forward looking efficient equity raising costs that were calculated using the AER's methodology and assumptions as follows:
>
> - dividends are assumed to be paid at the benchmark payout ratio of 70 per cent of after-tax profits reflecting the assumptions underlying imputation credits
> - retained earnings of 30% of after-tax profits are assumed to be available at zero costs

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310 When investing in shares, where the company has a dividend re-investment plan in place, investors may be offered dividends in cash, or may simply 'tick a box' to have the dividends automatically re-invested.

311 Western Power 2012, *Amended access arrangement information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 draft decision*, www.erawa.gov.au, p. 176.

- 25% of dividends are assumed to be returned to the business through a dividend reinvestment plan at a cost of 1%
- any further equity requirement is assumed to come from seasoned equity offerings at a cost of 3%.

These assumptions are encompassed in the modelling of the regulated revenue model and result in $35.8 million ($ real at 30 June 2012) for the purposes of determining the revenue requirement.

1190. The Authority notes that Western Power's summary set out in paragraph 1189 is incorrect. Specifically, Western Power had proposed that 30 per cent of dividends were assumed to be returned to the business through a dividend reinvestment plan at a cost of 1 per cent, rather than the 25 per cent stated above.[312] The Authority in its Draft Decision undertook analysis of recent data, which suggested that around 25 per cent of annual dividends are returned to the firm under dividend reinvestment plans.[313] That said, by adopting 25 per cent, Western Power is accepting the Authority's Draft Decision. The Authority therefore does not object to this aspect of Western Power's amended approach.

1191. With regard to the costs associated with DRP, the Authority in its Draft Decision assumed that these are virtually costless to the firm. In support of this position, the Allen Consulting Group found that companies often underwrite a DRP with a broker, but that competition between brokers resulted in the cost for the underwriting service falling from 1 to 2 per cent to zero, as brokers earned a fee by placing the stock at a higher price than the discounted dividend reinvestment plan price.[314]

1192. However, Western Power in its revised proposed revisions to the access arrangement noted that it had assumed costs for DRP of 1 per cent of the amounts raised, as this was consistent with approach taken by the Australian Energy Regulator (**AER**). The Authority notes that the AER, in deciding on its approach, took account of a number of studies, as well as its own investigations, concluding:[315]

> The AER has undertaken its own research of the costs of DRPs among domestic energy network businesses. The AER observed that where reported, costs as a portion of equity raised had a median of 0.75 per cent and a mean of 1 per cent. On the basis of all the information considered including the ACG report [zero costs] and Carlton's anecdotal evidence [1.25 per cent], the AER considers that a conservative estimate of 1 per cent is appropriate. The AER considers that this figure is the appropriate unit cost to be applied to the amount of equity assumed to be raised through a DRP.

1193. The Authority has reconsidered this matter in light of the foregoing evidence from Western Power in support of the proposed approach. The Authority accepts 1 per cent as a reasonable cost for dividend reinvestment as adopted by Western Power in the revised proposed revisions to the access arrangement.

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312 Western Power 2011, *Access arrangement information for 1 July 2012 to 30 June 2017*, www.erawa.gov.au, p. 246.

313 Economic Regulation Authority 2012, *Draft Decision on Proposed Revisions to the Access Arrangement fro the Western Power Network*, www.erawa.com.au, p. 424.

314 Allen Consulting Group, 2004, *Debt and Equity Raising Transactions Costs: Final Report*, Report to the Australian Competition and Consumer Commission, www.aer.gov.au, p. 63.

315 Australian Energy Regulator 2009, *Australian Capital Territory Distribution Determination 2009-10 to 2013-14*, www.aer.gov.au, p. 258.

1194. To this end, the Authority has amended the cost of raising equity for the purposes of determining the revenue requirement to be consistent with this approach (refer Table 122 and Table 123).

Adjustments to Target Revenue

Access Code Requirements

1196. Section 6.4 of the Access Code provides for the target revenue for an access arrangement period to include certain amounts "carried over" from the previous access arrangement period, including:

- an amount in respect of costs incurred as a result of a force majeure event under sections 6.6 to 6.8 of the Access Code;
- an amount in respect of costs incurred as a result of changes to the Technical Rules, for which no allowance was made in the access arrangement, under sections 6.9 to 6.12 of the Access Code;
- an amount under an investment adjustment mechanism under sections 6.13 to 6.18 of the Access Code;
- an amount under a gain sharing mechanism under sections 6.19 to 6.28 of the Access Code; and
- an amount under a service standards adjustment mechanism under sections 6.29 to 6.37 of the Access Code.

Current Access Arrangement

1197. The current access arrangement provides for several revenue adjustment mechanisms to adjust target revenue in the third access arrangement period to account for unforeseen events or other cost pass-throughs, over or under-recovery of revenue in preceding years or provide financial incentives to Western Power to be more efficient or perform better. These adjustments occur under the following mechanisms:

- Correction factor – a year-on-year adjustment to allowed revenue to account for under-recovery or over-recovery of revenue under the revenue cap.
- Unforeseen events adjustment – an adjustment to account for costs incurred in the current access arrangement period as a result of force majeure events.
- Technical rule change revenue adjustment – an adjustment to account for costs incurred as a result of changes to the Technical Rules that could not reasonably have been foreseen at the commencement of the current access arrangement period.
- Investment adjustment mechanism – an adjustment to account for differences between forecast and actual costs of certain classes of new facilities investment.
- Gain sharing mechanism – an adjustment to account for the out-performance of the forecast operating expenditure in the current access arrangement.
- Service standards adjustment mechanism – an adjustment to account for any difference between service standard performance and service standard benchmarks in the current access arrangement.
- D-factor – an adjustment to account for any additional operating expenditure incurred as a result of deferring a capital expenditure project, and any additional operating or capital expenditure incurred in relation to demand management initiatives.

- Deferred revenue from the current access arrangement – an adjustment to account for the amount of revenue deferred in the current access arrangement (as a result of an alternative treatment of capital contributions) which was to be recovered in subsequent access arrangement periods.

Proposed Revisions

1198. In its proposed revisions to the access arrangement, Western Power forecast adjustments to target revenue in the third access arrangement period in respect of the unforeseen events adjustment, investment adjustment mechanism, service standards adjustment mechanism and a full recovery of deferred revenue from the current access arrangement period.

1199. Western Power proposed to recover $7.5 million (in real dollar terms at 30 June 2012) in 2012/13 target revenue for an unforeseen event (i.e. a severe storm on 22 March 2010). Western Power provided a description of the event, a description of its insurance cover and an estimate of the unrecovered costs.[316]

1200. Under the investment adjustment mechanism, Western Power proposed to deduct $47.4 million from target revenue for the transmission network and add $2.0 million to target revenue for the distribution network (dollar values at 30 June 2012). These adjustments reflected actual spending of relevant capital expenditure being below forecast for the transmission network in the current access arrangement period and slightly above forecast for the distribution network.

1201. Western Power forecast a level of service performance for 2011/12 and determined that, over the current access arrangement period, it had incurred a penalty of $0.7 million for the transmission network and a reward of $3.1 million for the distribution network under the service standard adjustment mechanism. The current access arrangement requires that actual service performance for 2011/12 should be used rather than forecast, although actual performance would not be known until after 30 June 2012.

1202. In the current access arrangement, Western Power proposed an alternative treatment of capital contributions from its approach in the first access arrangement period, which had the effect of significantly increasing the revenue requirement. In its Final Decision for the current access arrangement, the Authority considered that, to avoid price shocks (as required by section 6.4(c) of the Access Code) and considering that the change in treatment of capital contributions policy should have a neutral commercial effect on Western Power’s business in present value terms, an amount of revenue should be deferred from the current access arrangement period to subsequent access arrangement periods. The amount of deferred revenue was $64.5 million for the transmission network and $484.2 million for the distribution network (real as at 30 June 2009).

1203. Western Power proposed to recover all of the deferred revenue in the third access arrangement period as a real annuity over the five-year period. This represents a revenue requirement of $967 million (in real 30 June 2012 dollars) during the third access arrangement period.

[316] Revised access arrangement information, Section 12.2.4, pp. 275-280.

Considerations of the Authority

1204. The Authority's considerations in relation to each of the proposed adjustments to target revenue are set out below.

Correction Factor

1205. The maximum reference service revenue formula included in the current access arrangement includes a correction factor that takes account of any difference between forecast maximum reference service revenue and the actual revenue earned in that year. Clauses 5.37 and 5.48 of the current access arrangement state that the correction factor will also apply in the first year of the next access arrangement period to adjust for any difference between the forecast and actual revenue in relation to the financial year commencing on 1 July 2011.

1206. Western Power set the annual tariffs for 2011/12 in April 2011. As this occurred prior to the end of the 2010/11 financial year, the maximum reference service revenue was based on forecasts of revenue for both 2010/11 and 2011/12.

1207. In the proposed revisions to the access arrangement, Western Power did not indicate any adjustment to target revenue in the third access arrangement period to account for under-recovery or over-recovery of revenue under the revenue-cap in 2010/11 and 2011/12.

1208. In the Draft Decision the Authority noted that actual revenue earned in 2010/11 was known and should be adjusted for in the assessment of target revenue for the third access arrangement period. Although actual revenue for the 2011/12 financial year had not then been finalised, Western Power should have been able to prepare a more accurate forecast of 2011/12 revenue than was possible in April 2011, which was the time when tariffs were set for the 2011/12 year, and to include an appropriate adjustment in target revenue for the third access arrangement period.

1209. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 25

The proposed revised access arrangement must be amended to include an adjustment to target revenue for the third access arrangement period taking account of any under-recovery or over-recovery of revenue under the revenue cap in 2010/11 and 2011/12.

1210. In response to the Draft Decision, Western Power has accepted this amendment and revised sections 5.6.7 and 5.77 of the revised proposed revisions to the access arrangement to provide for adjustments due to differences between the 2010/11 forecast revenue and the 2011/12 forecast revenue and the actual revenues for these respective periods.

1211. The Authority notes Western Power is forecasting significantly lower revenue for 2011/12 than was assumed in the 2011/12 Price List. The total adjustment amounts to $21.2 million for the transmission service and $10.3 million for the distribution service which represents approximately 5 per cent and 1 per cent respectively of Western Power's total revenue forecasts for 2011/12.

1212. These adjustments will result in prices for 2012/13 being higher than they would otherwise be by similar amounts. Consequently it is important the adjustments are as accurate as possible. As the 2011/12 financial year has now ended, Western Power should base the 2012/13 Price List on the actual revenue for 2011/12.

Required Amendment 19

The correction factor for under-recovery or-over recovery of revenue in the 2012/13 Price List must be based on the actual revenue for 2011/12.

1213. In the amended access arrangement information, Western Power notes it has made a further amendment to provide for corrections to the real value of the TEC:

> …the distribution revenue correction factor has been amended to provide for corrections to the real value of the tariff equalisation contributions (TEC). The revenue correction factor is calculated in real dollar terms whilst the TEC remains constant in nominal dollar terms. The conversion of the TEC from nominal dollars to real dollars results in different values when forecasts of inflation are utilised compared to when actual inflation is known. The amendment to the distribution revenue correction factor corrects for the differences in the real TEC value that arise due to differences between forecast and actual inflation.

1214. The Authority does not consider Western Power's proposal in relation to the TEC is necessary. The maximum target revenue formula, as set out in 5.7.6 of the revised proposed revisions to the access arrangement includes a separate component for the TEC. This component must be based on the amount required to be paid by a notice made under section 129D(2) of the EI Act. As the amount is expressed in nominal values and is known in advance of setting a price list, the amount included in each price list will reflect the actual nominal value. Therefore, there is no need to adjust that amount in future years. Consequently the Authority requires Western Power's proposed amendment to be removed.

Required Amendment 20

Western Power's amendments for corrections to the real value of the TEC must be removed from the distribution revenue correction factor set out in section 5.7.7 of the revised proposed revisions to the access arrangement.

Unforeseen Events Adjustment

1215. The unforeseen events adjustment is set out in clauses 5.4 to 5.6 of the current access arrangement as follows:

> 5.4 If a *force majeure event* occurs which results in Western Power incurring *unrecovered costs* during the *access arrangement period* then Western Power will, as part of its proposed access arrangement for the next *access arrangement period*, provide a report to the Authority setting out:
>
> (a) a description of the *force majeure event*;
>
> (b) a description of the insurance cover that Western Power had in place at the time of the *force majeure event*; and
>
> (c) a fair and reasonable estimate of the *unrecovered costs* borne by Western Power during the *access arrangement period* as a result of the occurrence of the *force majeure event*.

5.5 Pursuant to sections 6.6 to 6.8 of the Code, an amount will be added to the *target revenue* for the *covered network* for the next *access arrangement period* in respect of the *unrecovered costs* relating to a *force majeure event* which occurred in the *access arrangement period*, calculated in accordance with the methodology described in section 4 of Appendix 8 of this *Access Arrangement*.

5.6 For the avoidance of doubt, a *force majeure event* includes but is not limited to any costs arising from the introduction of an emissions trading scheme; full retail contestability; and the roll-out of Advance Interval Meters to the extent that such costs were not included in the calculation of *target revenue* for the *access arrangement period* or otherwise addressed through the Trigger Event provisions in section 8 of this *Access Arrangement*.

1216. Section 4 of Appendix 8 of the current access arrangement sets out the calculation method to be used:

> This provision for revenue adjustment covers those costs (termed “unrecovered costs” in section 6.6 of the Code) which are net of any insurance payment or other cost recovery, and which were incurred prudently.
>
> It is proposed that the expenditure included in the adjustment to *target revenue* for unrecovered costs be treated as an addition to the forecast revenue entitlement submitted in the next *access arrangement period*. This amount is to be spread evenly over each year of the next *access arrangement period.*
>
> To give effect to this purpose, the adjustment to the *target revenue* for the next *access arrangement period* must leave Western Power economically neutral by taking account of:
>
> a) The effects of inflation, both in this *access arrangement period* and the next; and
>
> b) The time value of money as reflected by the real pre-tax WACC as applied in this *access arrangement period* and the next.

1217. Western Power proposed an adjustment to target revenue for the third access arrangement period of $6.9 million (in real dollar terms at 30 June 2012) to recover costs arising from a severe storm that occurred on 22 March 2010. In the access arrangement information, Western Power noted that on 22 March 2010 a severe storm front passed over Perth bringing heavy rainfall, hail and strong winds up to 120 kilometres per hour. Western Power stated that approximately 250,000 customers were affected with around 8,000 MWh of load unavailable for 31 hours and six substations affected.

1218. Western Power noted that costs being claimed were recorded against specific work orders created for the March 2010 storm and included the costs of replacing uninsured assets and additional operational expenditure such as outage payments, third party contractors engaged as a result of the event, material procured, meals and accommodation greater than usual allowances and overtime for Western Power staff or embedded contractors.

1219. Western Power noted that it does not have insurance for its poles and overhead lines and provided a description of its insurance arrangements on pages 278 to 279 of the proposed revised access arrangement information:

> “We maintain an insurance program at a quality and coverage consistent with good electricity industry practice. At all times, our insurance has reflected the level of cover

> available in commercial insurance markets and is of a standard of a reasonable and prudent person.
>
> Our insurance program covers all corporate insurance exposures including property, public and products liability, motor and workers compensation, as well as other minor insurance classes. Our property insurance covers damage to physical assets including buildings, terminals and substations. Equipment other than that which is on or within 300 metres of an insured structure is not covered. The policy specifically excludes damage to transmission and distribution poles and overhead lines. All above ground transmission and distribution lines, including wire, cables, poles, pylons, towers, other supporting structures and any equipment of any type which may be attendant to such installations are not covered by an insurance policy.
>
> Prior to 2001, we had some coverage for damage to transmission and distribution poles and overhead. However, insurers have since ceased provision of this cover and as a result we are unable to obtain insurance cover for transmission and distribution poles and overhead lines."[317]

1220. Western Power included the following in support of its assertion that the amount to be claimed was in addition to insurance claims:

> "At the time of the March 2010 storm, the terms of our property insurance policy required that a deductable amount of $500,000 be paid for each and every claim. The March storm caused significant damage to our uninsured poles and wires, but only minor damage to other insured assets (e.g. buildings, depots, substations).
>
> As we do not hold insurance for transmission or distribution poles or overhead wires and the total value of losses for insured assets was within our deductable amount, no claims were made against insurance policies held by the business. Therefore the unrecovered amount of $5.9 million is additional to any claims made on insurance policies.
>
> In light of the above analysis, we seek an adjustment to target revenue for AA3, in order to recover the efficient and unrecovered costs of $6.9 million in present value terms for the March 2010 storm."[318]

1221. The total amount claimed was $5.92 million (dollars June 2012). However, under the current access arrangement, the adjustment to target revenue at the beginning of the third access arrangement period must leave Western Power economically neutral by taking account of inflation and the time value of money as reflected by the WACC applied in the access arrangement period. Western Power calculated that an adjustment with a net present value at the beginning of the third access arrangement period of $6.9 million dollars (dollars June 2012) is required to be added to the target revenue in the third access arrangement period to leave Western Power economically neutral.

1222. In the Draft Decision, the Authority noted that the recently published report by the Standing Committee on Public Administration in relation to wood poles[319] paid particular attention to Western Power's proposed claim for the costs of the March

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317 Western Power 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, www.erawa.com.au , p 278.

318 Western Power 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, www.erawa.com.au , p 280.

319 Legislative Council Western Australia, Thirty-Eighth Parliament Report 14 Standing Committee on Public Administration "Unassisted Failure" January 2012, pp. 147 to 156.

2010 storm, both in relation to Western Power's insurance arrangements and whether the event qualified as a force majeure event.

1223. In relation to Western Power's insurance arrangements, the report noted that there was an inconsistency between statements made in Western Power's 2011 Management Representation Letter to the Auditor General and statements contained in Western Power's proposed revised access arrangement information submitted to the Authority on 30 September 2011.

1224. Western Power's Management Representation Letter stated that:

> "All insurable assets and risks are to the best of our knowledge and belief fully covered by insurance."

However, as noted above, in the information submitted to the Authority, Western Power stated that its insurance policy specifically excludes damage to transmission and distribution poles and overhead lines and that all above ground transmission and distribution lines, including wire, cables, poles, pylons, towers, other supporting structures and any equipment of any type that may be attendant to such installations are not covered by an insurance policy.

1225. The Committee noted in its report that it had been separately advised by one of Australia's major re-insurance companies that it is prepared to re-insure electricity network wooden power poles and that that would require the assessment of risk and the setting of an appropriate re-insurance premium. The Committee also noted Western Power's responses to questions the Committee raised regarding the availability of insurance for its network wooden power poles. These are copied below[320]:

> "Western Power's view is that the factors assessed by insurers, the cost of insurance and the limited scope of the cover provided has resulted in its poles not being commercially insurable. The cost of maintaining the network is not insurable.
>
> Insurance for physical damage to wooden power poles has been either unavailable or not financially feasible since 2000/01 due to reinsurance treaty restrictions."

1226. The Committee took the view that there is a difference between insurance being unavailable versus not being commercially feasible. The Committee observed that generally non-disclosure of relevant information may result in an insurance policy being invalid and that if Western Power's asset records were deficient to a material extent that was not fully disclosed to an insurer and an insurance contract was entered into based on imperfect knowledge of asset condition, an insurer may have cause to avoid any subsequent claim for unassisted wooden power pole failure.

1227. The Committee asked Western Power to advise whether it had adequate asset condition data for its network wooden power poles to satisfy insurance requirements and whether Western Power had made any attempts to seek insurance since 2001. The Committee's report notes that at the time the Report was adopted (January 2012), the Committee was still awaiting a satisfactory response.

1228. The information provided by Western Power to the Committee was that there were strong winds up to 120 kilometres per hour. The Committee highlighted that industry standards require wooden power poles to be able to withstand winds, transverse to

[320] Standing Committee Report 14, p. 148.

the relevant line, up to 140 kilometres per hour. The Committee considered that the risk of poles falling in winds up to 120 kilometres per hour, due to them having been constructed at lower standards, should have been foreseeable to Western Power.

1229. The Authority acknowledges that industry standards have changed over time and that many of Western Power's wooden poles would have been installed when industry standards were lower. However, as Western Power itself acknowledged in a statement to the Committee:

> "Good industry practice is to operate the network with a good risk profile, with a good process for determining the serviceability of poles, and to replace them over time in a way that is both affordable and able to be resourced. … You can have a situation where a pole might fall at 120 kilometres per hour because it is built to an earlier standard, but it is not feasible to go out and rebuild the network every time a standard changes. "

1230. The Authority agrees with the Committee's view that the risk of poles falling in winds less than 120 kilometres per hour, due to them having been constructed to an earlier standard, was foreseeable to Western Power. Western Power's pole management policy should take account of such risks when assessing the level and timescale of pole replacement and reinforcement.

1231. "Force majeure" is defined in the Access Code as a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome. The Authority recognises that the March 2010 storm was a major event. However, taking account of the fact that recorded winds during the storm were below the level that industry standards require wooden power poles to be able to withstand, the Authority does not consider that Western Power has sufficiently demonstrated that it took all steps that a reasonable and prudent person would to prevent or overcome the physical and financial damage that arose from the storm.

1232. In the Draft Decision the Authority required the following amendment to the proposed revised access arrangement.

> **Draft Decision Amendment 26**
>
> No adjustment to target revenue for the third access arrangement period should be made in relation to unforseen events.

1233. In response to the Draft Decision, Western Power has accepted the amendment and removed the amount claimed from target revenue. The Authority considers the revised proposed revisions to the access arrangement fully comply with Draft Decision Amendment 26.

Investment Adjustment Mechanism

1234. The investment adjustment mechanism is set out in clauses 5.50, 5.51 and 5.53 of the current access arrangement, as follows.

> 5.50 The investment adjustment mechanism will apply to both transmission and distribution capital expenditure. The purpose of the investment adjustment mechanism is to adjust Western Power's target revenue in the next access arrangement period in a manner that exactly corrects for the economic loss or gain to Western Power as a result of forecasting errors in relation to particular categories of capital expenditure (the investment difference) in this access arrangement period. In order to give effect to this purpose, the investment adjustment mechanism must take account of:

(a) The effects of inflation, both in this access arrangement period and the next access arrangement period;

(b) The time value of money as reflected by the real pre-tax WACC as applied in this access arrangement period and the next access arrangement period; and

(c) The cost of depreciation and the value of capital additions to the capital base at the next access arrangement period.

5.51 Given the requirements of the investment adjustment mechanism as described in section 5.50 above, Western Power's approach is to calculate the difference in present value terms between:

(a) The target revenue that would have been calculated for this access arrangement period if the investment difference had been zero (i.e. there was no forecasting error in relation to the capital expenditure categories that are subject to the investment adjustment mechanism); and

(b) The target revenue that actually applied in this access arrangement period.

The adjustment to target revenue in the next access arrangement period should be such that its present value is equal to the present value of the difference described above.

5.53 For the purposes of calculating the investment adjustment mechanism, the categories of capital expenditure that are used in calculating the investment difference are:

(a) new facilities investment arising from the connection of new generation capacity to the transmission or distribution network from 1 July 2009;

(b) new facilities investment arising from the connection of new load to the transmission system or distribution system from 1 July 2009;

(c) new facilities investment in relation to the augmentation of the capacity of the transmission system or distribution system for the provision of covered services from 1 July 2006; and

(d) new facilities investment undertaken for augmentation of the distribution system under the regional power improvement program and state underground power program.

1235. In the proposed revisions to the access arrangement, Western Power calculated amounts of adjustments under the investment adjustment mechanism as compound returns on amounts of above-forecast new facilities investment under the relevant categories at the rate of return applying under the current access arrangement (6.76 per cent pre-tax real). No allowance for depreciation has been included in the adjustments. These calculations are summarised in Table 137 and Table 138.

Table 137 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – transmission network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	149.4	174.3	183.1
Customer-driven	67.2	142.9	252.5
Generation driven	28.8	147.6	97.6
Total	245.4	464.8	533.2
Actual capital expenditure (net)			
Capacity expansion	115.0	52.0	64.1
Customer-driven	23.4	24.6	33.2
Generation driven	28.6	5.0	0.0
Total	167.0	81.6	97.3
Above or (below) forecast investment			
Capacity expansion	(34.4)	(122.3)	(119.0)
Customer-driven	(43.8)	(118.3)	(219.3)
Generation driven	(0.2)	(142.6)	(97.6)
Total	(78.4)	(383.2)	(435.9)
Adjustment to target revenue Cumulative return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	0.0	(6.25)	(36.84)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	(43.6)		

Table 138 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – distribution network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	89.2	113.8	107.6
Customer-driven	106.3	106.5	106.3
State Undergrounding Power Program	6.0	5.8	5.7
Rural Power Improvement Program	8.7	0.0	0.0
Total	210.2	226.2	219.6
Actual capital expenditure (net)			
Capacity expansion	66.5	35.4	54.4
Customer-driven	140.8	156.0	128.8
State Undergrounding Power Program	16.4	12.0	19.6
Rural Power Improvement Program	8.7	-0.2	0.0
Total	232.3	203.3	202.8
Above or (below) forecast investment			
Capacity expansion	(22.7)	(78.4)	(53.2)
Customer-driven	34.5	49.5	22.5
State Undergrounding Power Program	10.4	6.2	13.9
Rural Power Improvement Program	0.0	(0.2)	0.0
Total	22.1	(22.9)	(16.8)
Adjustment to target revenue Cumulative return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	0.0	1.76	(0.07)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	1.8		

1236. In its assessment of the amounts determined by Western Power under the investment adjustment mechanism, the Authority has addressed:

- whether the amounts to be added to the target revenue for the third access arrangement period have been calculated correctly and consistently with the methods of financial modelling applied for the determination of target revenue; and
- whether the above-forecast new facilities investment is able to be added to the capital base for the network under section 6.51A of the Access Code, allowing Western Power to earn a return on the investment.

1237. The calculation of amounts to be added to target revenue must be consistent with the methods of financial modelling applied for the determination of target revenue. This requires consistency with the implicit timing assumptions for costs and revenues and with the methods applied in calculation of the capital base. In the Draft Decision the Authority verified the calculations of Western Power and is satisfied that the method of calculations has been undertaken appropriately. However, the Authority has not accepted the actual amounts, which are subject to the adjustment as discussed below.

1238. As set out in its review of the opening capital base for the third access arrangement period in the Draft Decision, the Authority determined that not all of the capital expenditure incurred, or estimated to be incurred, during the second access arrangement period meets the requirements of section 6.51A of the Access Code and therefore required that the amount added to the capital base be reduced from the amount proposed by Western Power. The Authority's amended capital expenditure for the second access arrangement period is set out in Table 56 above. As a consequence, the amount of adjustment under the investment adjustment mechanism also changed, as shown in Table 139 and Table 140 below.

Table 139 Authority's amended adjustments to target revenue under the investment adjustment mechanism – transmission network (real $ million at 30 June 2012) -Draft Decision

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	149.4	174.3	183.1
Customer-driven	67.2	142.9	252.5
Generation driven	28.8	147.6	97.6
Total	245.4	464.8	533.2
Authority amended actual capital expenditure (net)			
Capacity expansion	107.9	48.6	50.1
Customer-driven	17.4	27.6	0.0
Generation driven	27.2	0.5	0.0
Total	152.6	76.7	50.1
Above or (below) forecast investment			
Capacity expansion	(41.5)	(125.6)	(133.0)
Customer-driven	(49.7)	(115.4)	(252.5)
Generation driven	(1.6)	(147.1)	(97.6)
Total	(92.8)	(388.1)	(483.1)
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	(7.4)	(38.4)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	(46.4)		

Table 140 Authority's amended adjustments to target revenue under the investment adjustment mechanism – distribution network (real $ million at 30 June 2012) -Draft Decision

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	89.2	113.8	107.6
Customer-driven	106.3	106.5	106.3
State Undergrounding Power Program	6.0	5.8	5.7
Rural Power Improvement Program	8.7	0.0	0.0
Total	210.2	226.2	219.6
Actual capital expenditure (net)			
Capacity expansion	66.6	34.9	47.5
Customer-driven	141.2	155.6	131.5
State Undergrounding Power Program	16.5	12.0	2.4
Rural Power Improvement Program	8.5	-	-
Total	232.8	202.5	181.4
Above or (below) forecast investment			
Capacity expansion	(22.6)	(78.9)	(60.0)
Customer-driven	34.9	49.1	25.2
State Undergrounding Power Program	10.5	6.1	(3.3)
Rural Power Improvement Program	(0.2)	-	-
Total	22.6	(23.7)	(38.2)
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	1.8	(0.1)
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	1.9		

1239. As discussed in paragraph 662 above, Western Power has updated its forecasts of expenditure for the second access arrangement period. Taking account of the amendments required by the Authority in Required Amendment 11, the Authority has updated Table 139 and Table 140 accordingly with the revised values shown in Table 141 and Table 142 below.

Table 141 Authority's amended adjustments to target revenue under the investment adjustment mechanism – transmission network (real $ million at 30 June 2012) -Final Decision

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	147.5	172.0	180.7
Customer-driven	66.3	141.1	249.2
Generation driven	28.5	145.7	96.4
Total	242.3	458.8	526.3
Authority amended actual capital expenditure (net)			
Capacity expansion	106.5	48.0	19.0
Customer-driven	17.2	27.2	27.9
Generation driven	26.9	0.5	0.0
Total	150.6	75.7	46.9
Above or (below) forecast investment			
Capacity expansion	-41.0	-124.0	-161.7
Customer-driven	-49.1	-113.9	-221.3
Generation driven	-1.6	-145.2	-96.4
Total	-91.7	-383.2	-479.4
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	-7.3	-37.9
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	-45.8		

Table 142 Authority's amended adjustments to target revenue under the investment adjustment mechanism – distribution network (real $ million at 30 June 2012) -Final Decision

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	88.1	112.4	106.2
Customer-driven	104.9	105.1	104.9
State Undergrounding Power Program	5.9	5.8	5.6
Rural Power Improvement Program	8.6	-	-
Total	207.5	223.3	216.7
Actual capital expenditure (net)			
Capacity expansion	65.8	34.5	47.7
Customer-driven	139.4	153.6	95.6
State Undergrounding Power Program	16.3	11.8	7.7
Rural Power Improvement Program	8.6	-0.2	-
Total	230.0	199.7	151.0
Above or (below) forecast investment			
Capacity expansion	-22.3	-77.9	-58.5
Customer-driven	34.5	48.4	-9.3
State Undergrounding Power Program	10.4	6.0	2.0
Rural Power Improvement Program	-	-0.2	-
Total	22.5	-23.6	-65.7
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	1.8	-0.1
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	1.9		

Service Standards Adjustment Mechanism

1240. The current access arrangement Service Standards Adjustment Mechanism (**SSAM**) provided incentives for Western Power to maintain and improve service standard performance over time. The SSAM provides financial rewards for performance improvements relative to Service Standard Benchmarks (**SSB**), and financial penalties for under-performance relative to the SSBs. The resulting net incentive reward or penalty is carried forward to contribute to the total revenue for Western Power in the first year of the third access arrangement period.

1241. The provisions for the current access arrangement SSAM are set out in sections 5.15 – 5.24B of the current access arrangement. Clause 5.24A notes:[321]

[321] Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 15.

...the reward for good performance or penalty for poor performance is remunerated by applying the applicable incentive rate to the relevant Service Standard Difference (**SSD**) for each year of the *access arrangement period*, which is calculated as follows:

$SSD_{2009/10} = (SSB_{2009/10} – SSA_{2009/10})$

$SSD_{2010/11} = (SSB_{2010/11} – SSA_{2010/11}) - (SSB_{2009/10} – SSA_{2009/10})$

$SSD_{2011/12} = (SSB_{2011/12} – SSA_{2011/12}) - (SSB_{2010/11} – SSA_{2010/11})$

Where:

SSD_t is the service standard difference in year t;

SSB_t is the service standard benchmark in year t; and

SSA_t is the actual service performance in year t.

1242. Under clauses 5.24A(e) and 5.24B(d) of the current access arrangement, an amount must be added to or subtracted from Western Power's target revenue for the third access arrangement period that, in present value terms, is equal to the aggregate of the bonuses and penalties earned or incurred over the second access arrangement period. The intention of the present value calculation is to ensure that the amount added to or subtracted from Western Power's target revenue has the same financial effect as if the rewards or penalties applied in each year immediately following the performance year.

1243. At the time Western Power submitted its proposed revisions to the access arrangement actual service standards performance data was only available for the first two years of the current access arrangement period. Accordingly, Western Power's proposed amount included rewards or penalties for the transmission and distribution networks based on forecast performance in the final year of the current access arrangement period (that is, for 2011/12). Western Power forecast that penalties would apply for 2011/12, with a particularly large penalty for the distribution network.

1244. The total adjustment proposed by Western Power relating to the performance of the transmission network during the current access arrangement is a penalty with a present value at the beginning of the third access arrangement period of -$0.7 million (real 30 June 2012 dollars).

Table 143 Transmission service standards adjustment mechanism parameters as submitted by Western Power in its proposed revisions to the access arrangement

	2009/10	2010/11	2011/12 (forecast)
Service standard benchmarks			
Circuit availability (% of total time)	98.0	98.0	98.0
System minutes interrupted - meshed (minutes)	9.3	9.3	9.3
System minutes interrupted - radial (minutes)	1.4	1.4	1.4
Actual service performance			
Circuit availability (% of total time)	98.4	97.9	97.7
System minutes interrupted - meshed (minutes)	8.9	6.7	9
System minutes interrupted - radial (minutes)	0.8	4.8	1.5
SSAM adjustment ($ million real at 30 June 2012)			
Circuit availability	1.8	-2.2	-0.8
System minutes interrupted - meshed	0.3	1.9	-1.9
System minutes interrupted - radial	0.2	-1.1	0.9
Total	**2.2**	**-1.4**	**-1.8**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**-0.7**		

Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 271.

1245. The total adjustment proposed by Western Power relating to the performance on the distribution network during the current access arrangement period is a reward with a present value at the beginning of AA3 of $2.8 million (real 30 June 2012 dollars).

Table 144 Distribution service standards adjustment mechanism parameters as submitted by Western Power in its proposed revisions to the access arrangement

	2009/10	2010/11	2011/12 (forecast)
Service standard benchmarks			
SAIDI - CBD	38	38	38
SAIDI - Urban	165	162	153
SAIDI - Rural Short	259	253	244
SAIDI - Rural Long	612	588	556
SAIFI - CBD	0.24	0.24	0.24
SAIFI - Urban	1.92	1.89	1.83
SAIFI - Rural Short	3.12	3.06	2.98
SAIFI - Rural Long	5.00	4.85	4.80
Actual service performance			
SAIDI - CBD	1	30	22
SAIDI - Urban	156	120	166
SAIDI - Rural Short	212	192	263
SAIDI - Rural Long	661	529	604
SAIFI - CBD	0.02	0.23	0.18
SAIFI - Urban	1.55	1.31	1.94
SAIFI - Rural Short	2.33	2.11	3.00
SAIFI - Rural Long	4.17	3.86	4.58
SSAM adjustment ($ million real at 30 June 2012)			
SAIDI - CBD	8.9	-7.0	1.9
SAIDI - Urban	2.2	7.9	-13.2
SAIDI - Rural Short	0.4	0.1	-0.7
SAIDI - Rural Long	-0.4	1.0	-1.0
SAIFI - CBD	2.5	-2.4	0.6
SAIFI - Urban	4.2	2.4	-7.8
SAIFI - Rural Short	0.4	0.1	-0.5
SAIFI - Rural Long	0.4	0.1	-0.4
Total	**18.5**	**2.2**	**-21.1**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**2.8**		

Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 272 and ERA calculations.

1246. In the Draft Decision the Authority considered that the calculation by Western Power of the service standards adjustment for the third access arrangement for the transmission and distribution networks was largely consistent with the mechanism set out in the current access arrangement. On this basis, the Authority accepted Western Power's overall approach.

1247. However, Western Power had based its calculation of the adjustment to target revenue on a proposed weighted average cost of capital of 8.82 per cent for the 2012/13 financial year. In the Draft Decision the Authority did not approve Western Power's proposed weighted average cost of capital and instead approved a post tax weighted average cost of capital of 3.87 per cent. Taking account of the revised weighted average cost of capital the Authority recalculated the reward for the service standard adjustment in relation to the distribution service. The penalty relating to the transmission service was unchanged as the impact of correcting the weighted average cost of capital was negligible.

1248. The Draft Decision required the reward in relation to the distribution service to be amended.

Draft Decision Amendment 27

The reward in relation to the service standard adjustment mechanism for the distribution service must be amended to use the Authority's approved post tax WACC of 3.87 per cent.

1249. In response to the Draft Decision, Western Power agrees that the reward in relation to the SSAM should reflect the weighted average cost of capital. However, Western Power does not accept the Authority's estimate and has based its calculation on a real post-tax WACC of 6.39 per cent.

1250. As set out in paragraphs 1302 to 1313, the Authority has updated its estimate of the post-tax WACC for the final decision to 3.6 per cent. The Authority therefore requires Western Power to amend the reward in relation to the SSAM to reflect the Final Decision WACC.

Required Amendment 21

The reward in relation to the service standard adjustment mechanism must be amended to use the Authority's approved post tax WACC of 3.6 per cent).

1251. The Authority noted in the Draft Decision that Western Power had used a forecast of 2011/12 transmission and distribution networks performance to calculate the service standard adjustment. Western Power's proposed revisions to the access arrangement included transitional targets and incentive rates for the 2011/12 year in clause 7.5.13, which it proposed to use at the fourth access arrangement review to make any adjustment for differences between the actual performance for 2011/12 and the forecast performance. Whilst the incentive rates were consistent with those set for the second access arrangement period (indexed to June 2012 prices), the proposed transitional service standard benchmarks were not consistent with the benchmarks set for the second access arrangement. The Authority considered that the adjustment made at the beginning of the fourth access arrangement period to take account of any difference between the actual network performance in 2011/12 and the forecast performance should be based on the incentive rates and benchmarks set out in the second access arrangement.

Draft Decision Amendment 28

Section 7.5 of the proposed access arrangement must be amended to include an adjustment resulting from any differences between forecast and actual network performance in 2011/12, based on the service standard benchmarks set for the second access arrangement period – to be made to target revenue at the beginning of AA4.

1252. In response to the Draft Decision, Western Power has noted in the amended access arrangement information that it accepts the amendment and has revised section 7.5 accordingly. The Authority considers this amendment adequately deals with Draft Decision Amendment 28.

1253. Western Power submitted its Service Standard Performance Report for 2011/12 to the Authority on 15 August 2012. Actual performance in 2011/12 has improved compared with the forecasts proposed by Western Power in its submission in May. For the purposes of the Final Decision, the Authority has updated target revenue to reflect the actual service standard performance for 2011/12. The improved performance relates in a total reward of $30 million, compared with $1.2 million in Western Power's proposal, and is set out in Table 145 and Table 146 below. A copy of Western Power's Service Standard Performance Report for 2011/12 is included as Appendix 11 to the Final Decision.

Table 145 Transmission service standards adjustment mechanism parameters updated for actual performance for 2011/12

	2009/10	2010/11	2011/12
Service standard benchmarks			
Circuit availability (% of total time)	98.0	98.0	98.0
System minutes interrupted - meshed (minutes)	9.3	9.3	9.3
System minutes interrupted - radial (minutes)	1.4	1.4	1.4
Actual service performance			
Circuit availability (% of total time)	98.4	97.9	98.5
System minutes interrupted - meshed (minutes)	8.9	6.7	4.0
System minutes interrupted - radial (minutes)	0.8	4.8	2.5
SSAM adjustment ($ million real at 30 June 2012)			
Circuit availability	1.7	-2.1	2.3
System minutes interrupted - meshed	0.3	1.8	2.2
System minutes interrupted - radial	0.2	-1.1	0.6
Total	**2.2**	**-1.4**	**5.1**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**5.9**		

Table 146 Distribution service standards adjustment mechanism parameters updated to reflect actual performance for 2011/12

	2009/10	2010/11	2011/12
Service standard benchmarks			
SAIDI - CBD	38	38	38
SAIDI - Urban	165	162	153
SAIDI - Rural Short	259	253	244
SAIDI - Rural Long	612	588	556
SAIFI - CBD	0.24	0.24	0.24
SAIFI - Urban	1.92	1.89	1.83
SAIFI - Rural Short	3.12	3.06	2.98
SAIFI - Rural Long	5.00	4.85	4.80
Actual service performance			
SAIDI - CBD	1	30	16
SAIDI - Urban	156	120	119
SAIDI - Rural Short	212	192	191
SAIDI - Rural Long	661	529	563
SAIFI - CBD	0.02	0.23	0.16
SAIFI - Urban	1.55	1.31	1.20
SAIFI - Rural Short	2.33	2.11	2.10
SAIFI - Rural Long	4.17	3.86	4.33
SSAM adjustment ($ million real at 30 June 2012)			
SAIDI - CBD	8.9	-7.0	3.3
SAIDI - Urban	2.2	7.9	-1.9
SAIDI - Rural Short	0.4	0.1	-.1
SAIDI - Rural Long	-0.4	1.0	-.6
SAIFI - CBD	2.5	-2.4	0.8
SAIFI - Urban	4.2	2.4	0.6
SAIFI - Rural Short	0.4	0.1	-0.0
SAIFI - Rural Long	0.4	0.1	-0.3
Total	**18.5**	**2.2**	**1.8**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**23.7**		

1254. The Authority therefore requires that target revenue is updated to reflect actual service standard performance for 2011/12.

Required Amendment 22

The service standard adjustment mechanism in target revenue must be updated to reflect actual service standard performance for 2011/12.

Deferred Revenue

1255. In the current access arrangement, Western Power proposed an alternative treatment of capital contributions from its approach in the first access arrangement period, which had the effect of significantly increasing the revenue requirement. To avoid price shocks (as required by section 6.4(c) of the Access Code) and considering that the change in treatment of capital contributions policy should have a neutral commercial effect on Western Power's business in present value terms, an amount of revenue was deferred from the current access arrangement period to subsequent access arrangement periods.

1256. In its proposed revisions to the access arrangement, Western Power proposed to recover all of the deferred revenue in the third access arrangement as a real annuity over the five-year period. This amounted to a revenue requirement of $967 million (in real 30 June 2012 dollars) for the third access arrangement period. Western Power did not consider that recovering the deferred revenue over this period would result in a price shock. Western Power also considered it improves inter-generational equity as future users are not paying for assets used by current users and it avoids equity raising costs.

1257. Western Power noted that if it recovered the revenue as proposed, the total amounted to $976 million (real dollars at 30 June 2012) compared with it being recovered over the life of the assets for which the total would be $2.9 billion (real dollars at 30 June 2012). Western Power commissioned a report from NERA and stated "NERA Economic Consulting has reviewed this issue and concluded that deferring the AA2 revenue further would lead to intergenerational inequity and a requirement for Western Power to recover equity raising costs".[322]

1258. Until 30 September 2011, the Access Code did not include any provisions in relation to deferring revenue. An amendment to the Access Code was gazetted on 30 September 2011 to insert the following new clauses as set out below:

> **Recovery of deferred revenue**
>
> 6.5A In this Chapter, **"deferred revenue"** means the amounts referred to in paragraphs 5.37A and 5.48A of the Amended Proposed Revisions dated 24 December 2009 to the *Western Power Network access arrangement*, as approved by the *Authority's further final decision* dated 19 January 2010, expressed in present value terms as at 30 June 2009 and in real dollar values as at 30 June 2009, being respectively:

322 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au.

(a) $64.5 million; and

(b) $484.2 million.

6.5B An amount in respect of *deferred revenue* must be added to the *target revenue* for the *Western Power Network* for one or more *access arrangement periods* until the aggregate amount referred to in section 6.5E has been added.

6.5C An amount added to the *target revenue* under section 6.5B must include an adjustment so that the deferral of the *deferred revenue* is financially neutral for the Electricity Networks Corporation, taking into account:

(a) the time value of money; and

(b) inflation.

6.5D The *Authority* must determine the amount to be added under section 6.5B in a given *access arrangement period*.

6.5E The total of all amounts added under section 6.5B (aggregated over all *access arrangement periods* for which such amounts are added) must equal:

(a) the total amount of the *deferred revenue*;

plus:

(b) the sum of all adjustments under section 6.5C.

1259. The Access Code amendment codifies what was already taken into account by Authority and included in the access arrangement approved by the Authority for the current access arrangement period. The new provisions do not prescribe over what period the revenue should be recovered, with the Authority being required to determine the amount to be added to target revenue for each access arrangement period.

1260. Each element of Western Power's justification for recovery of all of the deferred revenue in the third access arrangement is addressed below.

Price Shock Considerations

1261. The Authority's final decision in the current access arrangement to include the deferred revenue mechanism in Western Power's access arrangement had particular regard to the price control objective of section 6.4(c), being the avoidance of price shocks where a price shock is defined as a sudden material tariff adjustment between succeeding years.

1262. Under the first access arrangement, the value of any new facilities investment financed by contributions was added to the capital base and the value of contributions was deducted from target revenue. This treatment left Western Power financially neutral in respect of the financing of new facilities investment by contributions as it earned future revenues from depreciation allowances and a rate of return on the value of the investment added to the capital base and incurred an equivalent cost (in net present value terms) by having the value of the contributions deducted from the value of revenue able to be recovered under the price control. For the first access arrangement the Authority accepted this treatment as consistent with the requirement of section 6.51A(b) of the Access Code for the value of investment financed by capital contributions to be added to the capital base.

1263. For the current access arrangement, Western Power proposed that any new facilities investment financed by contributions would not be added to the capital base. The proposed change in treatment was also financially neutral to Western Power as it did not meet the cost of the new facilities investment that is the subject of the contribution and nothing was included in its target revenue in relation to either the expenditure or the contribution received.

1264. However, this change in treatment resulted in higher reference tariffs for the current access arrangement period than would have been the case under the previous treatment of capital contributions. To mitigate this, Western Power proposed to defer some revenue from the current access arrangement period and adjust target revenue in future periods to add amounts in respect of part or all of the deferred revenue from the second access arrangement period. This would, in effect, spread the increase in reference tariffs over a period longer than just the second access arrangement period.

1265. As set out in its final decision for the current access arrangement, the Authority considered that the avoidance of price shocks would best occur through deferring the entire amount of the resultant increment to target revenue that would occur in the second access arrangement period and a planned recovery of deferred revenue by a pre-determined schedule over an extended period, such as by a real annuity amount over a period equal to the average life of network assets. However, based on cash-flow modelling submitted by Western Power following the draft decision, the Authority accepted that recovery of deferred revenue over a long period may have adverse effects on Western Power's business due to effects on cash flows and considered that this effect on Western Power's business should be taken into consideration in determining a time path for recovery of deferred revenue that avoids price shocks for users of reference services.

1266. The Authority also noted that, following the draft decision for the current access arrangement, Western Power presented projections of increases in reference tariffs to indicate that the recovery of deferred revenue may be able to occur in the third access arrangement period without a significant price shock for users. However, these projections were based on forecasts of costs that were subject to change. Consequently, the Authority determined that it would consider alternative timing of recovery, at the time of revisions to the access arrangement and having regard to the extent of any change in reference tariffs that is caused by recovery of part or all of the deferred revenue.

1267. In line with its final decision for the current access arrangement, to determine whether Western Power's proposal to recover all of the deferred revenue during the third access arrangement results in price shock to customers, in the Draft Decision the Authority considered both the effect on tariffs relating to the recovery of deferred revenue and the overall change in reference tariffs.

1268. In its proposed revisions for the third access arrangement, Western Power stated that it does not consider that the 'recovery of all of the deferred revenue as a real annuity causes a price shock during AA3', as the proposed average price increase for the third access arrangement is equal to or lower than the average price increase over the current access arrangement period. In the Draft Decision the Authority noted that the size of the increases under the second access arrangement was large and it did not agree that just because customers have previously been subject to large price increases, customers should continue to expect similar increases in the future.

1269. Table 147 below sets out Western Power's proposed tariff increases for the third access arrangement and the increases Western Power's consultants, NERA, calculated would arise if the deferred revenue was recovered over the life of the assets. In its modelling, NERA assumed that the tariff profile for the years 2013/14 to 2016/17 proposed by Western Power is retained and prices in 2012/13 are adjusted in order to achieve the target revenue required.

Table 147 Western Power's Proposed Tariff Increases Assuming Deferred Revenue is Recovered Over the Life of the Assets

	2012/13 Tariff increase %	2013/14-2016/17 Annual tariff increase %
Western Power's proposal:		
Transmission	12.9 + CPI	4.5 + CPI
Distribution	17.6 + CPI	13.4 + CPI
NERA's estimate of tariff increases if revenue was recovered over the life of the assets:		
Transmission	10.3 + CPI	4.5 + CPI
Distribution	9.6 + CPI	13.4 + CPI

1270. The Authority noted that, even without recovering all of the deferred revenue during the third access arrangement period, the tariff increases proposed by Western Power were in the order of 10 per cent before adding CPI. Against this background, the Authority considered Western Power's proposal to add a further 2.6 per cent to transmission tariffs and 8 per cent to distribution tariffs resulted in a significant sudden and material increase compared with the tariffs in place in 2011/12.

1271. The Authority noted that the submission from the Office of Energy supported Western Power's proposal to recover all of the deferred revenue in the third access arrangement period. However, the Authority's view was that Western Power's proposal as set out in the table above would result in a price shock to customers.

Impact on Cash Flows

1272. As noted above, in the Final Decision for the current access arrangement the Authority accepted that recovery of deferred revenue over a long period may have adverse effects on Western Power's business due to effects on cash flows, and considered that this should be taken into account in determining a time path for recovery of deferred revenue which avoids price shocks for customers.

1273. However, the Authority considers that the price control provides adequate revenue to meet the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved. As noted above, Western Power had not provided any evidence to the Authority to contradict this view.

Considerations relating to inter-generational equity

1274. In the Draft Decision the Authority noted that the value of deferred revenue is adjusted to ensure that, regardless of the period over which it is recovered, the effect on Western Power's target revenue is neutral in NPV terms. As a result, the longer the period over which the revenue is deferred, the greater the total value of the revenue recovered in nominal terms.

1275. Western Power and the Office of Energy argued that this leads to inter-generational inequity as, from a consumer perspective in nominal terms, deferring revenue results in lower prices in the short term, but leads to higher prices in the long term.

1276. In the access arrangement information Western Power submitted that:

> "Recovering all deferred revenue during the AA3 period meets the Access Code objective by ... improving inter-generational equity as future users are not paying for assets used by current users."

1277. In the Draft Decision the Authority noted that this submission by Western Power appeared to be derived from a statement in the NERA report that any deferral of revenue as a response to the change in treatment of capital contributions will cause benefits of the change in treatment to be lost, including improved inter-generational equity as future users are not paying for assets used by current users.[323]

1278. The Authority does not necessarily agree with Western Power that inter-generational equity (or, more precisely, equity between users paying for network services in different regulatory periods) is a relevant consideration in considering the timing of recovery of deferred revenue. Neither the Code objective nor the price control objectives include specific objectives relating to achieving "equity" as an end in itself.

1279. As a related matter, NERA claimed that the deferral of revenue results in outcomes that are economically inefficient, in particular less "allocatively" efficient.[324] This claim derived from considerations that the deferral of revenue may result in current customers facing network tariffs less than the true cost of supply and less than the marginal cost of supply leading to "over-consumption" of network services.

1280. The Authority was of the view that NERA's claim was not supported by evidence to establish any efficiency implications of deferring revenue. Deferral of revenue and a decision whether to recover deferred revenue in the third access arrangement or over a longer time frame does cause a shift in cost recovery and a difference in network tariffs between current and future network users. However, whether this causes inefficiency in use of network services depends upon whether, and to what extent, there is any resultant change in network use in response to different network tariffs. NERA did not provide evidence on this issue.

1281. The reasons presented by Western Power relating to inter-temporal shifts in cost recovery and inter-generational equity therefore did not, in the Authority's view, support the case for recovering all of the deferred revenue in the third access arrangement. While it is possible that the determination of whether to recover all of the deferred revenue in the third access arrangement or over a longer period may

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323 NERA, 1 September 2009, pp. 11, 12.

324 NERA, 1 September 2009, pp. 11, 12.

have efficiency implications in the use of network services, any inefficiency from recovery over a longer period has not been demonstrated.

1282. The Authority was therefore unable to give any weight to Western Power's claim of inefficiency in assessing Western Power's proposal.

Determination of Recovery Period

1283. In the Draft Decision the Authority noted Verve Energy's view that using asset lives may be too slow a recovery process and its suggestion that the Authority find a "middle-ground" solution, e.g. 10 years. A similar suggestion was made by Alinta.

1284. As noted above, in its final decision for the current access arrangement, the Authority considered that the avoidance of price shocks would best occur by deferring the entire amount of the current access arrangement increment to target revenue and instead recovering this deferred revenue by a pre-determined schedule over an extended period, such as by a real annuity amount over a period equal to the average life of network assets.

1285. In the Draft Decision the Authority considered the period over which the deferred revenue should be recovered. The impact of various options on overall tariffs is set out in Table 148 below.

Table 148 Authority's Comparison of Different Recovery Periods for Deferred Revenue

Option	Transmission Annual % change to tariffs during AA3	Distribution Annual % change to tariffs during AA3	Overall Annual % change to tariffs during AA3
Authority's preferred approach from the current access arrangement-recovered over life of assets	**CPI - 11.4%**	**CPI + 0.3%**	**CPI - 2.3%**
Alternative A – recovered over 10 years	CPI - 10.6%	CPI + 2.5%	CPI - 0.4%
Alternative B – recovered over 5 years	CPI - 9.6%	CPI + 5.2%	CPI + 2.1%

1286. The Authority noted that reducing the recovery period from the average life of the assets to 10 years (or two access arrangement periods) resulted in average tariffs reducing by around 0.4 per cent per annum in real terms whilst recovering the revenue over 5 years (Western Power's proposal) resulted in increases in average tariffs of 2.1 per cent per annum in real terms.

1287. The Authority noted that, assuming these tariffs were passed through to retail customers, the overall increase customers would observe would be considerably less than the above figures as network charges comprise only about 40 per cent of retail tariffs.

1288. Based on the forecast price increases resulting from the Authority's Draft Decision, the Authority considered that a recovery period of less than the life of the assets could be accommodated without resulting in a price shock to customers. For the purposes of the Draft Decision the Authority adopted a period of 10 years.

1289. However, the Authority considered it would be necessary to review this period as part of its Final Decision to take account of the overall forecast price increases and to ensure that it would not result in a price shock.

Draft Decision Amendment 29

The proposed access arrangement must be amended to recover deferred revenue over ten years and include a similar provision to the existing access arrangement regarding how this will be reviewed at AA4.

1290. In response to the Draft Decision, Western Power has accepted recovery of the deferred revenue over a 10 year period and has added a new section 7.7 to the access arrangement to detail the adjustment that will need to occur to target revenue in the next access arrangement period to recover the outstanding amount of deferred revenue.

1291. As the overall forecast price increases in this Final Decision are similar to those projected in the Draft Decision, the Authority maintains its view that a recovery period of 10 years can be accommodated without resulting in a price shock to customers. The Authority is satisfied that Western Power has complied with Draft Decision Amendment 29.

Tariff Equalisation Contributions

Access Code Requirements

1292. Section 6.37A of the Access Code provides for an amount to be added to target revenue in relation to tariff equalisation contributions (**TEC**) that comprises an amount levied on users of the Western Power Network to finance amounts paid to Horizon Power for the provision of electricity services in areas not serviced by the Western Power Network:

6.37A If the service provider for the Western Power Network is or will be required, by a notice made under section 129D(2) of the Act, to pay a tariff equalisation contribution into the Tariff Equalisation Fund during an access arrangement period, then an amount may be added to the target revenue for the covered network for the access arrangement period, which amount—

(a) must not exceed the total of the tariff equalisation contributions which are or will be required to be paid under the notice, including any amount that was payable or paid before the commencement of the access arrangement period; and

(b) must be separately identified as being under this section 6.37A.

Proposed Revisions

1293. The State Government periodically gazettes the TEC amounts but, at the time of Western Power's submission of its proposed revisions to the access arrangement, had yet to gazette any amounts for the TEC beyond 2011/12. Consequently Western Power included $906.9 million (in dollar values at 30 June 2012) in its target revenue for the TEC for the third access arrangement period, which it stated was based on forecasts provided in the State Budget indexed in line with inflation.

Table 149 Tariff equalisation contributions

	Current Access Arrangement (nominal $ million)			Third Access Arrangement (real $ million at 30 June 2012)				
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Approved tariff equalisation contributions[325]	129.7	180.1	181.2	-	-	-	-	-
Forecast tariff equalisation contributions[326]	-	-	-	181.2	180.7	180.8	181.7	182.5

Considerations of the Authority

1294. As set out in the Draft Decision, the Authority considers that the TEC is not an efficient tool to achieve social policy. However, under section 6.37A of the Access Code, an

325 Economic Regulation Authority, 4 December 2009, Final Decision, p. 272 (forecast values of 30 June 2009 divided by 0.91 to derive values in dollars of 30 June 2012).

326 Revised access arrangement information, Section 12.4, Table 88.

amount in respect of a TEC may be added to target revenue if the service provider is required by a notice under section 129D(2) of the *Electricity Industry Act 2004* to pay the same amount into the tariff equalisation fund.

1295. Submissions received from Energy Made Cleaner and WACOSS in response to the Draft Decision indicated agreement with the Authority's views. Energy Made Cleaner considers the current charging arrangements result in the TEC being a hidden tax on private retailers. WACOSS considers it artificially inflates electricity prices and has a disproportionate impact on low income households because they spend a high percentage of their income on electricity. However, as noted above, the Access Code requires such amounts to be added to target revenue.

1296. At the time of the Draft Decision the State Government had not gazetted any amounts for the TEC beyond 2011/12. On 7 August 2012, amounts for the five years commencing 2012/13 were gazetted by the Treasurer as set out in Table 150 below.

1297. As noted in the Draft Decision, the price control includes a separate factor for the TEC. Consequently, the distribution revenue cap approved by the Authority excludes any amounts relating to the TEC. The Authority notes that, for the purposes of forecasting a smooth revenue profile, Western Power has included costs relating to the TEC but these costs have then been excluded from its proposed distribution revenue cap. In the Draft Decision the Authority adopted a similar approach to derive the approved revenue caps based on Western Power's forecast TEC. For the Final Decision the Authority has smoothed the revenue profile using the gazetted TEC.

Table 150 Gazetted Tariff equalisation contributions (nominal $ million at 30June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gazetted tariff equalisation contributions[327]	154.0	173.0	166.0	146.0	143.0

327 Revised access arrangement information, Section 12.4, Table 88.

RATE OF RETURN

Approach to Estimating the Rate of Return

Western Power's Initial Proposal

1298. Western Power proposed that the rate of return used in determining the total revenue and reference tariffs for the revisions to the access arrangement be determined as a real, pre-tax weighted average of the returns applicable to debt and equity. Western Power submitted that a real pre-tax WACC formulation is appropriate and also consistent with the Authority's preferences and that the formulation meets the Access Code requirements and remains appropriate for calculating the WACC for the access arrangement for the period from 1 July 2012 to 30 June 2017.

1299. In its submission to the first round of public consultation, Western Power noted that a move to a post-tax model would require considerable time to obtain the relevant data, modify the model and test the results. Western Power's view was that a change of this significance would require sufficient notice to enable it to happen and is best left until the next regulatory period.

1300. Western Power submitted that its approach to estimating the WACC was based on the following considerations:[328]

- Consultants' reports prepared by Strategic Finance Group (SFG) and Ernst & Young (E&Y);
- Recent developments in global capital markets, including the ongoing high level of volatility in the wake of the global financial crisis and the ongoing uncertainty surrounding sovereign debt in Europe and the United States;
- Examination of recent regulatory WACC decisions made by the AER and the decisions of the Australian Competition Tribunal (ACT) in related appeals; and
- Adoption of a pre-tax real WACC.

Draft Decision

1301. In the Draft Decision, the Authority noted there is a growing precedent for the post-tax form of the WACC to be used.

Pre-tax versus post-tax approaches

1302. The Authority noted that it had been using a real pre-tax WACC approach in its regulatory decisions because this method:

- avoided the need to forecast inflation ex ante in setting the overall price path;
- simplified financial modelling; and
- promoted consistency across regulated utilities in Western Australia.

[328] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 256.

1303. However, increasingly other regulators are moving to a post-tax WACC, recognising that the use of a pre-tax WACC tends to over-compensate service providers for their tax liabilities. In the Draft Decision the Authority took the view that this over-compensation does not meet the objectives of the Access Code, as it does not result in economically efficient pricing.

1304. The Authority observed that a number of Australian and foreign regulators adopt a post-tax modelling approach.

- The Queensland Competition Authority and New Zealand Commerce Commission (**NZCC**) currently adopt nominal post-tax modelling.
- The ACCC and the AER use a post-tax nominal form of the WACC.
- The Essential Services Commission of Victoria (**ESC**) has used a post-tax real form of the WACC.
- The UK regulators, Office of Gas and Electricity Markets (**Ofgem**) and Office of Water and the Water Services Regulatory Authority (**Ofwat**), currently adopt real post-tax modelling.

1305. With the recent decision by the Independent Pricing and Regulatory Tribunal of New South Wales (**IPART**) to move to a real post-tax WACC, the only remaining regulators in Australia, New Zealand and the UK using a pre-tax approach are the Independent Competition and Regulatory Commission (**ICRC**), and the Essential Services Commission of South Australia (**ESCOSA**). In the Draft Decision, the Authority noted that there is a legislative requirement for ESCOSA to use a pre-tax WACC when determining prices for SA Water.

1306. In the Draft Decision the Authority took the view that the use of an explicit post-tax approach allows a regulated entity's effective tax liabilities to be estimated more precisely, overcoming shortcomings with the pre-tax approach and thereby better meeting the price control objectives of the Access Code. The post-tax approach recognises that:

- 'earnings before tax' under the pre-tax WACC regulatory method differ from 'earnings before tax' under the actual post-tax method, reflecting differences in the respective depreciation schedules, as well as in the tax base itself;
- tax rebates and offsets may need to be incorporated; and
- accumulated tax losses and any expected changes in tax treatment can affect the timing of tax liabilities.

1307. An alternate method of approximating the post tax WACC calculation would be to apply an effective tax rate, rather than the statutory tax rate, to the pre-tax WACC calculation. This alternate method is impractical as no publicly available and reasonable estimates of benchmark effective tax rates exist. These effective tax rates would need to be modelled, which would require the same work as estimating the taxation liability under the post tax WACC method. However, the alternate method would be less transparent in application.

Table 151 Tax treatment in other jurisdictions

Regulator	Form of WACC	Nominal or real tax liability	Accumulated tax losses	Tax rate	Depreciation allowance	Gearing
AER[a]	Nominal post-tax	Nominal	Yes	Statutory	Tax	Benchmark
IPART[b]	Real post-tax (water)	Nominal	Yes	Statutory	Tax	Benchmark
ESC[c]	Real post-tax	Nominal	Yes	Statutory	Tax	Benchmark
ERA (existing)[d]	Real pre-tax	Real	No	Statutory	Regulatory	Benchmark
QCA[e]	Nominal post-tax	Nominal	No	Statutory	Tax	Benchmark
ESCOSA[f]	Real pre-tax	Real	No	Statutory	Regulatory	Benchmark
NZ Commerce Commission[g]	Nominal post-tax	Nominal	Yes, but limited	Statutory	Tax	Benchmark
UK Ofgem[h]	Real post-tax	Nominal		Statutory	Tax	Benchmark for low geared Actual for high geared
UK Ofwat[i]	Real post-tax	Nominal		Statutory	Tax	Benchmark for low geared Actual for high geared

Notes: All regulators allow for dividend imputation

a) Australian Energy Regulator 2010, Amendment : Electricity transmission network service providers Post-tax revenue model handbook, www.aer.gov.au.
b) IPART 2011, The incorporation of company tax in pricing determinations: Other industries – Final Decision, www.ipart.nsw.gove.au.
c) Essential Services Commission 2009, Melbourne Metropolitan Water Price Review 2008-09–Final Decision, www.esc.vic.gov.au.
d) Economic Regulation Authority 2012, Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, www.erawa.com.au.
e) Queensland Competition Authority 2010, Gladstone Area Water Board 2010 Investigation of Pricing Practices; Dalrymple Bay Coal Terminal 2010 Draft Access Undertaking, www.qca.com.au.
f) ESCOSA 2009, Metropolitan and Regional Water and Wastewater Pricing Process, www.escosa.com.au.
g) Airport Services Input Methodologies Determination December 2010; Commerce Act (Transpower) Input Methodologies Determination 2010; Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper December 2010.
h) Electricity distribution final price control review: final proposals, 2004.
i) Setting price limits for 2010-15: framework and approach, 2009.

Source: Authority analysis (but drawing extensively on IPART 2011, *The Incorporation of Company Tax in Pricing Determinations*, www.ipart.nsw.gov.au, p. 10).

1308. Accordingly, the Draft Decision required Western Power to model its tax liabilities explicitly, as a separate 'building block', in order to determine the revenue requirement for the third access arrangement period.

1309. Nominal modelling of the taxation building block tends to be implemented, irrespective of whether real or nominal post tax revenue modelling is adopted (refer to Table 151). In this case, the resulting nominal post-tax estimates of the tax liabilities may then be deflated to real terms using the estimate of future inflation, and incorporated into the real revenue model.

1310. There is no clear precedent to guide the choice between a real or nominal post tax modelling approach for the overall revenue requirement (refer to Table 151). There are advantages and disadvantages associated with each approach, and the issues are complex. The key issues include:

- the alignment or otherwise of the treatment of depreciation in the regulatory accounts and the tax accounts; and
- the best approach to smoothing the change in the real revenue over time.

1311. In the Draft Decision, the Authority considered that there are advantages in retaining a real revenue modelling framework. These advantages related principally to the ability to build on the real revenue model proposed by Western Power, while incorporating a post-tax approach. The Authority considered that this addressed a major shortcoming of the previous approach, thereby meeting the objectives of the Code, while enabling it to reach a decision within required time constraints.

1312. For these reasons, the Authority considered that a real post-tax approach, incorporating nominal modelling of the tax liabilities as a separate building block, should be adopted for the third access arrangement period.

1313. Western Power accepted this requirement in its response to the Draft Decision.

The Post-Tax 'Vanilla' WACC Formula:

1314. With separate modelling of tax liabilities, the appropriate WACC to apply is the post-tax 'vanilla' WACC. The nominal post-tax vanilla form of the WACC is expressed below:

$$WACC_{vanilla} = E(R_e) \times \frac{E}{V} + E(R_d) \times \frac{D}{V}$$

where:

- $E(R_e)$ is the nominal post-tax expected rate of return on equity - the cost of equity;
- $E(R_d)$ is the nominal pre-tax expected rate of return on debt - the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt); and
- D/V is the proportion of debt in the total financing.

1315. The real post-tax WACC is obtained by removing expected inflation π_e from the nominal post-tax WACC.

$$WACC_{\text{real, post tax}} = \frac{\left(1 + WACC_{\text{nominal, post tax}}\right)}{1 + \pi_e}$$

Western Power's response to the Draft Decision

1316. In response to the Draft Decision, Western Power has accepted the adoption of a real post-tax WACC on the basis that this method provides a more accurate estimation of tax liabilities than the pre-tax method. However, Western Power has not accepted the Authority's method for calculating tax payable, in particular, the Authority's method of applying the opening value of the regulatory asset base as the opening value of the tax asset base. The Authority has considered this matter further in paragraphs 1148 to 1180.

Final Decision

1317. Notwithstanding Western Power's response, and for the reasons set out below, the Authority remains of the view that the method used by it to calculate tax payable in the Draft Decision is the most appropriate approach for the third access arrangement period.

Regulatory Framework

Western Power's Response to the Draft Decision

1318. In the amended access arrangement information, Western Power has submitted that the mechanical application of a financial model to determine the reasonable return is not required by the Access Code. Western Power argued that if the mechanical application was required by the Access Code, then Section 6.4 would simply direct the application of such a model and there would be no need for a reference to the general factors of the return over the access arrangement period meeting the forward-looking and efficient costs of providing covered services and being commensurate with commercial risks.

Considerations of the Authority

1319. The Authority considers that Western Power's argument with respect to the construction of section 6.4 has some similarities with the "construction arguments" raised by Western Australian Gas Networks (**WAGN**) (now known as ATCO) and the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) in relation to section 87 of the National Gas Rules in separate gas access arrangement decision review proceedings before the Australian Competition Tribunal (**ACT**) in 2012.

1320. The Authority notes that, in its recent decision in the *Application by DBNGP (WA) Transmission Pty Ltd (No 3)* [2012] ACompT 14, released on 26 July 2012, the ACT considered an argument by the applicant to the effect that the Authority should not have utilised the outcome of a single financial model to determine the rate of return under the National Gas Rules, but should rather have adjusted the output of that model to arrive at an estimate of the cost of equity commensurate with prevailing conditions in the market for funds and with the risks involved in providing reference services.

1321. In rejecting the applicant's construction, the ACT observed that the approach advocated by the service provider provided no guidance to the Authority on *how* it should adjust the model output to reflect prevailing conditions in the market for funds and the risks in providing reference services. Absent such guidance, such an assessment would be "fraught and vulnerable to an evolutionary and possibly idiosyncratic series of regulatory decisions. It would provide less certainty. It would expose the process of selection of the rate of return on capital to the risk of prolonged debate about the relevant factors, their empirical measurement and their weighting."[329]

1322. Although sections 6.4 and 6.66 of the Access Code are in different terms to the relevant provisions of the NGR, the Authority is of the view that application of Western Power's construction of the Access Code provisions would give rise to similar issues of regulatory uncertainty as described by the ACT in the DBNGP decision.

1323. For the purposes of estimating the cost of equity, the Authority applied the Sharpe-Lintner CAPM; and similarly, for the purposes of estimating the cost of debt, used the Bond-yield approach to estimate the debt risk premium, together with the

[329] Australian Competition Tribunal, 2012, *Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14*, 26th July 2012, paragraph 84.

estimates of the nominal risk free rate and debt raising costs. Western Power was of the view that the outputs of the application of these models and processes (i.e. the return on equity and the return on debt) are not fit for the purposes of the Authority's determination on the cost of capital for Western Power under section 6.4 and that the "mechanical application of a financial model" is not what is required by the Access Code.

1324. The Authority agrees with Western Power's observation that no financial model is perfect. A financial model, regardless of how complex it is, is always developed based on a set of simplifying assumptions. However, not all models are of equal value and it is possible to distinguish between some financial models that are well accepted and others that are not.

1325. In its DBNGP review decision, the ACT noted that the applicant's criticisms of the Authority's use of a financial model to determine the WACC must be minimised, if not negated, by the requirement in the NGR that the approach and the model used must be "well accepted". The ACT held that if the approach and model are well accepted by those who determine rates of return on capital, "it is almost inherently contradictory then to say that the approach or the model is not likely to produce a reliable result – assuming the inputs are appropriate".[330]

1326. In conclusion, the Authority is of the view that when a well accepted financial model is applied to determine an estimate of the return on equity and the return on debt, using model inputs that reflect the prevailing conditions in the market for funds and the commercial risks involved in providing reference services, the output produced from the models will meet the price control objectives in section 6.4 and the Code objective. As a result, Western Power is given the opportunity to recover all its efficient costs and to earn an appropriate rate of return.

Nominal Risk Free Rate of Return

Wester Power's Initial Proposal

1327. Western Power adopted the yield on ten-year Commonwealth Government Securities (**CGS**), reported by the Reserve Bank of Australia (**RBA**), as a proxy for the nominal risk free rate. Western Power submitted that this approach was accepted by the Authority for the purpose of estimating Western Power's WACC for the current access arrangement, known as AA2, and also for decisions on Western Australia Gas Networks (**WAGN**) in 2011.

1328. Western Power noted that the Authority's adoption of a five-year term for the risk free rate is based on its view that there are strong grounds for matching the term to maturity of debt with the access arrangement period. Western Power, however, was of the view that the maturity of debt issuance is a separate issue to the maturity of the risk free rate used in the CAPM to estimate the cost of equity.

1329. In addition, Western Power was of the view that the term of the risk free rate used in the CAPM should be 10 years in order to achieve consistency with:

- the MRP that has been estimated historically (i.e. relative to the 10-year risk free rate);

[330] Australian Competition Tribunal, 2012, *Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14*, 26th July 2012.

- the objective of limiting volatility in the cost of capital allowance (protecting both customers and businesses from this volatility); and
- the price control objectives set out in section 6.4 of the Access Code, which in effect require that the cost of equity not be under estimated.

1330. Western Power proposed a nominal risk free rate of return of 5.40 per cent.[331] Western Power also noted that there are no Commonwealth Government bonds maturing in exactly 10 years. As such, Western Power was of the view that the appropriate nominal risk free rate is estimated by interpolating on a straight line basis between 15 May 2021 and 15 July 2022 Commonwealth Government bond yields. This is the average of 10-year CGS for the 20-trading day period commencing on 4 May 2011 and ending on 31 May 2011.

Draft Decision

1331. In the Draft Decision, the Authority noted that the risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth Government bond is widely used as a proxy for the risk free rate in Australia. CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, the current practice of regulators is to average the yield on the indexed 10-year Commonwealth Government bond for a period of 20 trading days. The AER has adopted an averaging period from 5 to 40 trading days as presented in their WACC Review in 2009. The Authority's current practice is to adopt a 20 trading day average as close as feasible before the decision is made for the purpose of estimating the nominal risk free rate.

1332. In its most recent draft and final decisions on Proposed Revisions to the Access Arrangement for the DBNGP, released in 2011, the Authority was of the view that there should be consistency between the terms of the risk free rate and the debt risk premium. In these decisions, the Authority concluded that there are strong grounds for matching the assumption of term to maturity with the regulatory period, which is generally 5 years. A term of the risk free rate that matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia. The Authority took the view that the use of a term of 5 years matching the regulatory period will result in correct compensation consistent with the "NPV=0" rule.[332] This principle requires the present value of the cash flow stream associated with the return on and of an asset to be equal to the present value of the cost of the asset so that regulated businesses are not over or under compensated.

1333. As a result, in these decisions, the Authority considered the nominal risk free rate of return should be estimated using yields from the 5-year Commonwealth Government bonds reported by the RBA. This conclusion was discussed in detail

[331] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 258.

[332] Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, October 2011, pp. 125-9.

in both the DBGNP Draft Decision released in March 2011[333] and Final Decision released in October 2011.[334]

1334. In addition, the Authority has been using the bond yield approach to estimate the debt risk premium for regulated businesses, which is discussed in the 'Debt Risk Premium" section of this Final Decision. The average term to maturity of Australian corporate bonds included in the benchmark sample in the bond yield approach used by the Authority, as at 29 February 2012, was 4.66 years.

1335. Each of Western Power's three concerns (as mentioned in paragraph 1329 above) about the adoption of the 5-year term to maturity for a nominal risk free rate, is discussed in turn below.

Consistency with the estimates of the MRP using historical data on equity return

1336. In previous regulatory decisions, the Authority has relied on an estimate of the historical equity risk premium for the period for 1883 – 2010 by Associate Professor Handley in January 2011, together with other pieces of information, to derive the evidence for the forward-looking long-term estimates of the MRP.

1337. The Authority is aware that, in his studies for the AER, Handley has used a 10-year term to maturity for the Commonwealth Government bonds in the estimates of the MRP using historical data on equity risk premium. This is a matter raised by Western Power in its submission, with regard to inconsistency between the adoption of the 5-year term to maturity for a nominal risk free rate of return and the estimates of the MRP.

1338. However, in the Draft Decision the Authority took the view that this claim by Western Power was not substantiated. The Authority was of the view that the estimate of the MRP of 6 per cent is supported when the 5-year term of the nominal risk free rate is adopted instead of the 10-year term adopted in Handley's study for the AER. The Authority's estimate of the MRP of 6 per cent was also supported by the results of the Authority's recent analysis of estimates of the historical equity risk premium in which a 5-year term to maturity for the Commonwealth Government bonds was adopted. Details are discussed in the "Market Risk Premium" section.

Consistency with the objective of limiting volatility in the cost of capital allowance

1339. The Authority was of the view that the allowance for the cost of capital should meet the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with covered services. All companies are exposed to fluctuations in their rates of return. As such, the Authority considers that any estimate of the WACC should reflect this volatility through the WACC parameters, particularly the market-based WACC parameters, such as the nominal risk free rate of return, the debt risk premium and expected inflation at or around the period in which the decision is to be made.

1340. In the Draft Decision, the Authority did not agree with Western Power's submission that using a 10-year term for the nominal risk free rate will limit the volatility of the

[333] Economic Regulation Authority, 2011, Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, March 2011, pp. 182-7.

[334] Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, October 2011, pp. 125-9.

cost of capital allowance. The Authority observed that the 5-year and 10-year CGS have similar volatility. As such, there is little merit in selecting the 10-year CGS over the 5-year CGS as a proxy for a nominal risk free rate of return on this basis. The Authority took the view that the principle under the regulatory regime is that the best forward looking estimate of the cost of capital should be used at the time an access arrangement decision is made. This approach is likely to deliver the best outcome because the cost of capital will reflect the current conditions in the market for funds and the commercial risks involved in providing the reference services.

Consistency with the price control objectives set out in section 6.4 of the Access Code

1341. Section 6.4 of the Access Code states that a return on investment must be commensurate with the commercial risks involved. This means that Western Power is allowed to earn a return that is consistent with the level of risk involved in providing its references services.

1342. As discussed above, in the Draft Decision the Authority took the view that the use of a term of 5 years, which matches the regulatory period, will result in appropriate compensation for the regulated businesses and is consistent with the objectives of section 6.4 of the Access Code.

1343. In the Draft Decision, the Authority did not approve Western Power's proposal in relation to the estimate of the nominal risk free rate of return using the 10-year term to maturity on Commonwealth Government bonds.

1344. The Authority is of the view that consistency is important in the overall framework of the estimate of the cost of capital and that all WACC parameters are closely related. As such, the Authority took the view that there should be consistency between the terms of the risk free rate and the debt risk premium. Based on analysis at the time of the Draft Decision, more than 50 per cent of debt profiles for both privately owned and government owned networks have an average term of less than five years, as presented in Table 160 and Table 161 of the Draft Decision. Data from Bloomberg also indicated that more than 50 per cent of total debt has a term to maturity of less than five years for Australian rated utilities, as presented in Figure 18 of the Draft Decision. In addition, the Authority took the view that a term of the risk free rate that matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia. This was based on the Authority's observations that bank financing and shorter term bonds or notes issued dominate the current debt profile of Australian companies.

Summary

1345. Taking account of the above matters, in the Draft Decision, the Authority considered the estimated nominal risk free rate of return should be 3.67 per cent using yields from 5-year Commonwealth Government bonds reported by the RBA, as at 29 February 2012. Based on an estimated nominal risk free rate of return of 3.67 per cent and an assumed inflation rate of 2.55 per cent, the Authority estimated a real risk free rate of 1.09 per cent.

Western Power's response to the Draft Decision

1346. In response to the Draft Decision, Western Power has accepted the Authority's approach to adoption of the yields on the CGS, reported by the RBA, as a proxy for the estimate of the nominal risk free rate.

1347. Western Power has adopted a risk free rate of 4.21 per cent, which is based on the 20 day average of spot rates to 30 March 2012.[335] The Authority understands that Western Power has used a 10-year term of the CGS to estimate the risk free rate.

1348. In its amended access arrangement information, Western Power has expressed the following two concerns with the approach of estimating the risk free rate:[336]

- the use of spot rates (a forward looking estimate) for the risk free rate and a backward looking estimate for the market risk premium; and
- the use of a five-year term to maturity understates the true cost of debt and is inconsistent with Section 6.4 of the Access Code.

1349. Western Power submitted that there are two issues with using spot rates to estimate the risk free rate:[337]

- use of too short a period increases the risk of the data being distorted by random factors; and
- in the current economic conditions, yields on bonds are reduced due to excess demand created by the "flight to quality" of risk averse investors.

1350. Western Power argues that an average of long term historical rates should be used as then the risk free rate would align with the estimate of the MRP. Western Power is also of the view that, if the Authority intends to use spot rates for the risk free rate, then it should also use a consistent approach for the determination of the MRP.[338]

Final Decision

1351. The Authority has considered each of the matters raised by Western Power in its amended access arrangement information below.

Approach to Estimating the Risk Free Rate

1352. Western Power submits that the Authority has erred by using a five-year term to maturity. Western Power proposed a range for the nominal risk free rate of 4.21 per cent to 5.99 per cent, based on analysis from CEG. The lower end of the range of 4.21 per cent is based on a 20-day average to 30 March 2012 using 10-year CGS and the upper end of 5.99 per cent is based on long term averages of indexed CGS rates plus a forward looking inflation premium of 2.5 per cent, as estimated by CEG.[339]

[335] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 153.

[336] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 153.

[337] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 153.

[338] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 153.

[339] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 154.

1353. Western Power is of the view that it is a conservative assumption to adopt the risk free rate at the lower end of the range of 4.21 per cent.[340]

1354. Grid Australia's submission in response to the Draft Decision noted that the Authority has applied the "spot" measure of the risk free rate, notwithstanding that the interest rates on Commonwealth bonds have fallen in the past year. It further notes a substantial body of opinion that this fall is due to investors seeking a safe haven during the current economic crisis, and that the returns required by investors in risky, long-lived investments would not have fallen to the same extent (and indeed, may have risen in view of the more risky investment climate). Grid Australia notes that during times of financial crisis, when government bond rates fall, the market risk premium does not remain at the long term average, but increases by an amount that is at least necessary for the estimated cost of equity not to be lower during the crisis, and with an even larger increase in the market risk premium expected in line with the intuition that the cost of equity should rise during the crisis. Based on this argument, it concludes that pairing the spot risk free rate (drawn from abnormal times) with the normal period market risk premium results in an understatement of the cost of equity.[341]

1355. The Authority has classified the issues raised by Western Power and its consultants into the following three broad themes:

- A forward-looking estimate of the risk free rate and a backward-looking estimate of the MRP;
- The term of the risk free rate; and
- The averaging period of the risk free rate.

1356. Each of these themes is discussed in turn below.

A forward-looking estimate of the risk free rate and a backward-looking estimate of the MRP

1357. The Authority considers that there is no inconsistency between the approaches it has taken to estimate the nominal risk free rate and the MRP.

1358. First, the Authority's analysis indicates that a 20-trading day averaging period is the best proxy for the average rate of the nominal risk free rate over the regulatory period of the next 5 years. The Authority is of the view that this conclusion can be applied to circumstances in which the average of the risk free rate, over the averaging period, over- or under-estimates the risk free rate of the regulatory period of 5 years. The details of this analysis are discussed from paragraph 1394 to 1403.

1359. Second, the Authority is of the view that the MRP is unobservable and is a forward looking concept. The Authority notes that a forward-looking approach used to estimate a forward-looking MRP, such as the Dividend Growth Model (**DGM**), exhibits significant drawbacks such as unreliable estimates of the inputs used in the model. As such, Australian economic regulators have preferred to use historical data on equity risk premiums to estimate the MRP. However, using historical data

[340] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 154.

[341] Grid Australia, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 6.

does not necessarily mean that the MRP is a backward looking estimate. Historical data is commonly used in quantitative studies in economics and finance to predict future events.

1360. The Authority is conscious of a potential level of imprecision from any method using historical data. The method of estimating the MRP using historical data of equity risk premium is no exception. However, this weakness is moderated by using a long data series on equity risk premium and references to other sources of evidence in relation to the estimate of the MRP. For example, Associate Professor Handley from the University of Melbourne had used historical data on equity risk premium back to 1883, although his conclusion was mainly based on the period since 1958 to 2012 due to a concern about data quality for the previous periods.

1361. In the Authority's previous decisions, an MRP of 6 per cent was determined based on various sources of evidence of which the estimate of the MRP using historical data on equity risk premium is only one source. For example, as discussed at length in the Draft and Final Decisions on DBNGP's Access Arrangement, the Authority estimated the MRP from several different sources of evidence, including the work of Associate Professor Handley for the AER, who based his estimates on ten-year Commonwealth Government bonds; other Australian regulatory decisions, including those of the AER, IPART and the Queensland Competition Authority; surveys of market risk practice; and qualitative information on the state of the Australian financial market.

1362. In addition, as presented in its Draft Decision on Western Power's proposed revisions to the access arrangement, the Authority recently conducted its own analysis to estimate the MRP using historical data on equity risk premium. In this study, the Authority used the longest possible historical data on 5-year CGS, back to 1968. Using the 5-year CGS as a proxy for the nominal risk free rate of return, the Authority concluded that an estimate of the MRP of 6 per cent falls within the estimated range of the MRP for different periods of time.

The term of the risk free rate

1363. As this matter is complex, it has been considered separately in paragraphs 1369 to 1403.

The averaging period of the risk free rate

1364. The Authority is of the view that the nominal risk free rate of return is a forward looking rate. As discussed in its Draft Decision, the Authority noted that the averaging period of 20 to 40 trading days is a standard practice of Australian economic regulators in relation to the estimate of the risk free rate.

1365. In its submission in response to the Draft Decision, the Department of Finance encouraged the Authority to reconsider the use of a 20 day average to calculate the risk free rate to ensure that Western Power is not locked into an artificially low return on its assets for the entire five year regulatory period as a result of market volatility.[342]

[342] Department of Finance, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 2.

1366. In addition, in response to a concern from Western Power and its consultant in relation to the averaging period, (which it proposes should be longer than 20 trading days to be consistent with the estimate of the MRP using historical data on equity premium) the Authority has recently conducted its own analysis to assist in its determination of which averaging period is the best proxy for the future regulatory period. Diebold-Mariano tests of forecasting efficiency were used. Based on this study, the Authority concluded that the averaging period of 20 trading days serves as the best proxy for the regulatory period of the next 5 years. This new study is discussed in detail in Appendix 9.

Conclusion

1367. The Authority disagrees with Western Power's submission that the estimate of the MRP is backward looking and that there is inconsistency between the estimates of the risk free rate (using a 20-trading day period) and the MRP (using historical data on equity risk premium). The Authority is of the view that a 20-trading day period is the best proxy for the estimate of the nominal risk free rate for the regulatory period over the next 5 years. In addition, the MRP is not observable in the present. As such, it is appropriate to use historical data to predict a forward-looking estimate of the MRP. The Authority is of the view that an estimate of the MRP using historical data on equity risk premium over a long period of time is appropriate as a forward looking estimate. Using historical data on equity risk premium for a long period of time to estimate the MRP assumes that investors expect that what occurred in the past is the best possible proxy for the future and as such, the estimate of the MRP should be considered as a forward looking estimate.

1368. The Authority concludes that the averaging period of 20 trading days continues to serve as the best proxy for the risk free rate of the regulatory period of 5 years.

Term of the Risk Free Rate

1369. In response to the Draft Decision, Western Power's consultant on the issue, CEG, submitted that, since the Sharpe Lintner CAPM is a "one period model", it is not possible to derive a 'correct' term for the risk free rate to be used in the model from theoretical considerations. CEG then proposed considering different grounds to decide whether a short or a longer term nominal risk free rate of return should be used. CEG put forward four arguments to support a conclusion that a long term risk free rate should be used. The following grounds were proposed by CEG:[343]

- consistency with how the MRP has been estimated;
- an objective of limiting volatility in the cost of capital allowance;
- matching the term of the risk free rate to utility investors' long term perspective (consistent with the life of the assets they own); and
- consistency with the term of the cost of debt.

1370. Each of these considerations is explained in turn below.

[343] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 49.

Consistency with how the MRP has been estimated

1371. CEG submits that the historical evidence relied upon by Australian economic regulators to justify a 6 per cent estimate for the MRP uses a 10-year risk-free rate. CEG then argued that it would be internally inconsistent to use a MRP estimated in conjunction with anything other than a ten year risk free rate.[344]

1372. CEG also submits that the choice of the risk free rate would have little effect on the estimate of the cost of equity if the MRP was based on prevailing market conditions. CEG is of the view that choosing a shorter term lower yielding CGS as the proxy for the risk free rate, for any given prevailing return on equity, will simply increase the MRP by the same amount as it reduces the risk free rate.[345]

An objective of limiting volatility in the cost of capital allowance

1373. CEG submits that yields on 10-year CGS are materially more stable than for CGS with shorter terms of maturity. Using its own analysis, CEG considered that the higher volatility of 5 year CGS is captured in statistical measures of volatility, where variance of the five year CGS bond rates is 0.56 for the period from 2005 to 2012. The variance of the ten year CGS bond rate is 0.36 for the same period. CEG concluded that this greater volatility of short term debt (i.e. five years) is exemplified during the recent global financial crisis, where short term bond rates fell much faster and further than long term bond rates (i.e. 10 years).[346]

1374. CEG considers that adopting a term shorter than 10 years for the CGS bond rate will increase the volatility of the estimated cost of equity. CEG also submits that if the Authority does not adjust the MRP to reflect prevailing, as opposed to historical market conditions, adopting the more volatile 5 year CGS rate will make the overall cost of equity estimate less accurate (too low when risk free rates are low and too high when risk free rates are high).[347]

Matching the term of the risk free rate to utility investors long term perspective

1375. CEG submits that the value of equity in a regulated business will, like the value of a long term bond, be determined by expectations of economic conditions in the long term. CEG also argues that because the payback period for the assets in question is long, then the term of the risk free rate should also be long.[348]

1376. On the advice of its consultant, CEG, Western Power submits that the Authority has failed to appreciate that the term of debt data taken from company accounts is the remaining life of the debt. This term of debt is not the term of the debt at the time of issue. Western Power argues that when determining the cost of debt funding, businesses need to be funded for the interest rate they commit to when they issue

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[344] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 50.

[345] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 50.

[346] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on pp. 52-3.

[347] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 53.

[348] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 53.

debt and this is determined by the term of the debt at the time of issue. Western Power is of the view that, the evidence presented by the Authority, once correctly interpreted, is entirely consistent with a 10 year term of debt at issue.[349]

Consistency with the term of the cost of debt

1377. CEG argues that as long as the risk free rate used to estimate the cost of debt must have a term of at least ten years, the same term of 10 year for the risk free rate must also be used to estimate the cost of equity; and that this assumption must be used in calculating the MRP.[350]

Public Submissions in response to Draft Decision

1378. Grid Australia notes that the AER has accepted that an assumption of a 10 year term of debt was reasonable. It explains in its submission that stand alone entities issue debt with an average term of more than 10 years because rating agencies would not be able to maintain an investment grade credit rating if all of their debt had a five year term. It considers the Authority's choice of a 5 year term to be inconsistent with the AER's practice.

1379. Further, it considers it to be inconsistent with the practice of the finance community when using the CAPM, where a 10 year assumption is standard in Australia. It concludes that the use of a 5 year risk free rate is, therefore, also inconsistent with how the "standard" Australian market risk premium of 6 per cent has been derived. Additionally, Grid Australia notes that because infrastructure assets are long term investments, the alternative "risk free" investment to these investors is a very long term bond (for which a ten year bond is the best available proxy). It states that using a shorter term bond as the risk free rate will lead to the Authority materially underestimating the returns that infrastructure investors receive during times when there is a large difference between the interest rates on short term and long term bonds, which is the case at the present time.[351]

1380. Energy Networks Association does not agree that a five year term to maturity better reflects financial strategies of an efficient network service provider and considers it a broadly accepted fact that network businesses prefer to issue long term debt in order to minimise refinancing risks.[352]

Considerations of the Authority

1381. The Authority has assessed each of the four issues raised by CEG in turn below.

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349 Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 153.

350 Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 53.

351 Grid Australia, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, pp. 5-8.

352 Energy Networks Association, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 4.

Consistency with how the MRP has been estimated

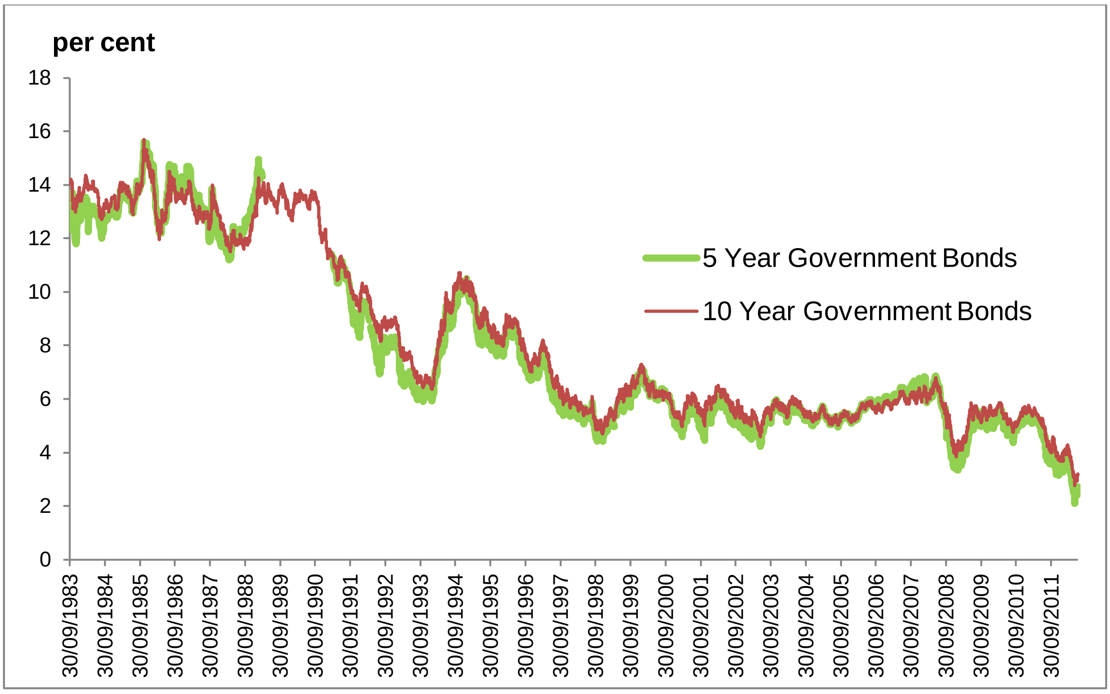
1382. As previously discussed from paragraph 1359 to 13621362, the Authority reconfirms its decision that there is no inconsistency between the methods adopted for the estimates of the risk free rate and of the MRP.

An objective of limiting volatility in the cost of capital allowance

1383. The Authority agrees with CEG's observation that, on average, observed yields on the 5-year CGS bonds are more volatile in comparison with those of the 10-year CGS bonds. However, the Authority is of the view that this observation does not necessarily mean that using a term of 5 years for a nominal risk free rate is inappropriate.

1384. The Authority notes that CEG has limited its analysis to the period from 2005 to 2012. The Authority has done its own analysis using the longest possible data available for observed yields on the 5-year and 10-year CGS bonds. The Authority's analysis covers the period from financial deregulation in 1983 to July 2012. Figure 10 below presents the co-movement between the 5-year and 10-year CGS bonds. More formal analysis indicates the two series are both co-integrated and they are also very highly correlated[353]. This means that the two series of 10-year and 5-year CGS bond yields are closely tied to one another and virtually always move in the same direction.

Figure 10 Observed Daily Yields on 5-year versus 10-year CGS, September 1983 – July 2012, per cent



Source: Bloomberg

353 The series have a correlation coefficient of 0.99. The augmented Engel-Granger co-integration test, in which one series is regressed on another, indicates that the two series are co-integrated.

1385. The Authority does not agree with the concept of a relatively unchanged estimate of the cost of equity through time, which has been raised by the CEG. The Authority is of the view that the cost of capital, including the cost of equity and the cost of debt, must reflect the prevailing conditions in the market for funds. As such, the cost of equity (or the return on equity) must also reflect the prevailing conditions in the market for funds. Since the prevailing conditions in the market for funds change, and this is always the case for the financial markets, then it follows that the return on equity will also change over time.

1386. If it is assumed that any decrease in the risk free rate is "compensated" via an associated increase in the value of the MRP, leaving the return on equity unchanged, then equity investors are always guaranteed a stable return on equity, regardless of the economic environment. The Authority considers that a stable return on equity is unlikely in practice.

1387. The Authority is of the view that ad hoc adjustments on any WACC parameter will violate the integrity of the entire framework of the WACC estimate. The Authority considers that the estimate of the cost of equity should reflect the prevailing conditions in the market for funds. The Authority is of the view that an estimate of a long term forward looking MRP of 6 per cent and a 20 day trading period for a 5-year term risk free rate are appropriate. Together with the estimated equity beta, these two WACC inputs are used to determine a cost of equity that best reflects the prevailing conditions in the market for funds.

1388. In conclusion, the Authority is not persuaded by the second issue raised by CEG.

Matching the term of the risk free rate to utility investors' long term perspectives

1389. Commencing with the draft and final decisions on DBNGP's proposed Access Arrangement released in 2011, the Authority has adopted the term to maturity of 5 years for the estimate of the risk free rate. This is a significant departure from the Australian regulatory practice on this issue over the last 10 years or so. This decision was mainly based on the following considerations:

- Academic papers by Associate Professor Lally[354,355] and expert advice to IPART by Professor Davis indicate that the term of the risk free rate should be equal to the term of the regulatory period, which is generally 5 years in Australia, based on the so-called "NPV = 0" principle: the present value of the cash inflow stream to be equal to the present value of the cost of the asset.
- Current debt profiles for Australian rated utilities prepared by S&P over the 4 years, from 2008 to 2011 inclusive, after the Global Financial Crisis in 2008.
- The current debt profiles for Australian privately owned companies and government owned companies.

1390. Based on various industry reports prepared by S&P for the period from 2008 to 2011 inclusive, the Authority concluded that current debt profiles for Australian rated utilities indicate that the appropriate term of debt for the sample of

[354] Lally, M. 2007, "Regulation and the Term of the Risk Free Rate: Implications of Corporate Debt", *Accounting Research Journal*, Volume 20, No. 2, 2007, pp. 73-80.

[355] Lally, M. 2004, "Regulation and the Choice of the Risk Free Rate", *Accounting Research Journal*, Volume 17, No. 1, 2004, pp. 18-23.

12 Australian rated utilities is, on average, approximately 5 years.[356] This is consistent with the findings of both Professors Lally and Davis.[357]

1391. The Authority does not agree with the argument on the term of debt for Australian rated utilities raised by Western Power and its consultant. On the advice of CEG, Western Power was of the view that the cost of debt was determined at the time when the debt instruments are issued, not their term to maturity and that the Authority's observation in relation to current debt profiles for Australian utilities are associated with the term to maturity of the debts, not their terms at issuance. The Authority considers that Australian businesses will raise funds with different terms to maturity from less than one year, one year, two years, three years, five years, and ten years and so on. Doing so will balance refinancing risk and liquidity risk and in doing so will minimise the interest payments for raising debt from the financial markets.

1392. The Authority considers that Australian businesses raise debts with different terms to maturity to balance risks associated with different terms of debt. For example, the Authority is conscious that short term debt may incur refinancing risks whereas long term debt may incur liquidity risks. As a result, current debt profiles for any business will include debt with various terms at issuance in order to balance liquidity and refinancing risks. This is an observation by S&P in their various reports for the Australian rated utilities. S&P industry reports indicate clearly that there are debt instruments with terms to maturity of less than 5 years; and more than 5 years. However, S&P presented data showing that more than 50 per cent of debt financing by Australian rated businesses is with terms to maturity of less than 5 years. This evidence confirms that Australian businesses have not preferred to raise long term debt, possibly due to the current economic environment. This is also an observation by the Authority.[358] The Authority is not convinced by the argument made by Western Power and its consultant that evidence presented by S&P in their industry reports indicates that the term of debt to maturity of 5 years is equivalent to the term of debt at issuance of 10 years.

Consistency with the term of the cost of debt

1393. The Authority adopted the bond-yield approach to estimating the debt risk premium for regulated businesses in December 2010. The Authority's bond-yield approach is based on observed yields of a benchmark sample of Australian corporate bonds.

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356 See Standard and Poor's, 2011, *Industry Report Card: Australian Utilities Are On A Firm Footing, But Confronting Regulatory Reviews*, 21 November 2011; Standard and Poor's, 2010, *Industry Report Card: Refinancing And Balance Sheet Management Remain Top Of The Agenda For Australian Utilities*, 5 May 2010; Standard and Poor's, 2009, *Industry Report Card: For Australian Utilities, The Challenge Remains To Manage Refinancing And Balance Sheets*, 7 May 2009; and Standard and Poor's, 2008, *Industry Report Card: Australian Utilities' Credit Prospects Dimmed By Looming Shadow of M&A, Climate, And Regulatory Risks*, 9 May 2008.

357 Australian Competition Tribunal, 2012, *Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14*, 26th July 2012, paragraph 137.

358 See Standard and Poor's, 2011, *Industry Report Card: Australian Utilities Are On A Firm Footing, But Confronting Regulatory Reviews*, 21 November 2011; Standard and Poor's, 2010, *Industry Report Card: Refinancing And Balance Sheet Management Remain Top Of The Agenda For Australian Utilities*, 5 May 2010; Standard and Poor's, 2009, *Industry Report Card: For Australian Utilities, The Challenge Remains To Manage Refinancing And Balance Sheets*, 7 May 2009; and Standard and Poor's, 2008, *Industry Report Card: Australian Utilities' Credit Prospects Dimmed By Looming Shadow of M&A, Climate, And Regulatory Risks*, 9 May 2008.

Australian corporate bonds must satisfy a set of practical criteria in order to be included in the benchmark sample. Among other criteria, bonds with terms to maturity of 2 years and longer are included in the sample. Over the last 3 years, the average term to maturity of all bonds included in the benchmark sample has been approximately 5 years. As such, if the term of the risk free rate is required to be consistent with the term of the cost of debt, the Authority is of the view that a 5-year term is currently appropriate. This appropriate term of the risk free rate may change in the future if the average term to maturity of bonds in the benchmark sample changes.

The term of the risk-free rate of return: Post Crisis Observations

1394. The Authority notes that Western Power and its consultant are concerned with a low risk free rate during global financial crisis and that the low level of risk free rate will not reflect the conditions over the regulatory period of the next 5 years. To overcome this low risk free rate, Western Power and its consultants proposed an upwards revision to the current estimate of the MRP of 6 per cent

1395. Gulko (2002)[359] tested the hypothesis that the stock-bond correlation is positive before equity market crashes and negative in the aftermath. The author examined daily returns of the Standard and Poor's (S&P) 500 Index and the on-the-run United States (US) Treasuries, the most frequently traded bonds, between 1946 and 2000. A short run event study around equity market crashes was constructed. The author defined equity market crashes as where the S&P 500 index decreased by more than five per cent in a single trading day. The author reported a statistically significant positive correlation between equities and bonds for the ten trading day period before crashes, which reversed in the period spanning two days before crashes until ten days after. The author interpreted this as evidence supporting a 'decoupling' between the two markets as investors flee to the relative safety offered by American Government Bonds.

1396. The Authority has conducted its own analysis by applying the same method as Gulko (2002) to the Australian market. The proxy for an equity market crash is a decline of five per cent or more in the All Ordinaries Accumulation Index in any single trading day, as adopted by Gulko (2002). These dates are outlined in Table 152.

[359] Gulko, L. (2002). Decoupling, The Journal of Portfolio Management, Vol 28, No. 3. pp. 59-66.

Table 152 A Nominal Risk Free Rate of Return: A Post Financial Crisis Analyses

Date	Day	All Ordinaries Decline %	20 Day Average Nominal Yield %	Average of Nominal Yield over the 5-year period %
20/10/1987	Tuesday	-28.75	13.49	11.39
23/10/1987	Friday	-7.27	13.45	11.38
26/10/1987	Monday	-6.58	13.45	11.38
27/10/1987	Tuesday	-7.20	13.47	11.37
29/10/1987	Thursday	-7.79	13.43	11.36
4/11/1987	Wednesday	-5.61	13.35	11.35
16/10/1989	Monday	-8.35	NA	NA
28/10/1997	Tuesday	-7.43%	5.99	5.89
17/04/2000	Monday	-5.85	6.41	5.67
22/01/2008	Tuesday	-7.54	6.15	5.06
8/10/2008	Wednesday	-5.09	5.21	4.87
10/10/2008	Friday	-8.55	5.24	4.87
16/10/2008	Thursday	-6.89	5.19	4.87
13/11/2008	Thursday	-5.59	4.60	4.87

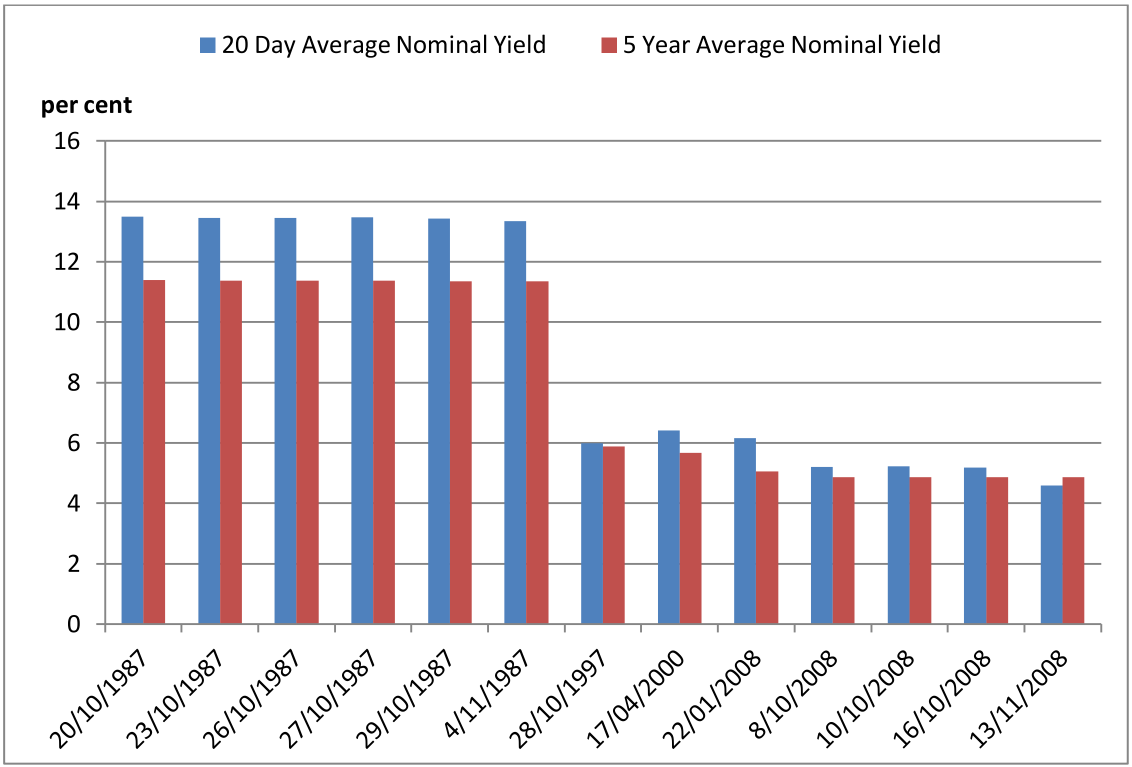
Source: Economic Regulation Authority's Analysis

1397. The twenty-day average nominal yield includes the yield on the date of the crash and yield on each of the 19 trading days after the crash on the ten-year Australian Government Treasury Bond Index taken from Bloomberg.[360] The five year average was taken over the 1,300 trading days after the last day of the twenty day average on the same index. It is noted that the Authority's recent analysis indicates that using 5-year CGS instead of 10-year CGS does not alter the outcome of the analysis. However, the Authority has decided to present the findings of the 10-year CGS in this study because there are more data points on the 10-year CGS in comparison with the 5-year CGS.

1398. The twenty day average after the crash overestimates the next five year average in twelve out of thirteen cases where data was available as presented in Figure 11. This is consistent with expectations based on the declining trend in Australian Government Treasury Bond yields since financial deregulation in 1983, that is any observation of the bond yield based on today's or past data is likely to be higher than the actual realisation in five years time given the declining trend.

[360] GACGB10 Index Mid Yield based on bid and ask prices.

Figure 11 20-Trading Averages versus Averages for the Next 5 Years Post Market Crashes



Source: Bloomberg and the Economic Regulation Authority's analysis

1399. This is also the outcome of the current access arrangement released in 2009. The Authority determined the nominal risk free rate adopted in the estimates of the WACC to be 5.51 per cent. It is noted that the actual average of the nominal risk free rate realised was 4.85 per cent, resulting in a gain of 66 basis points in Western Power's favour.

1400. The Authority's analysis shows that estimates of the risk free rate using the 20 day averaging period during various global financial crises were generally higher than that of the 5 year averaging period immediately after these economic crises, when the nominal risk-free rate is typically low. Therefore, an estimate of the risk free rate using a twenty day averaging period would have a strong tendency to over-compensate Western Power for the risk-free rate of return that would actually be realised over the next five years.

Conclusion

1401. Based on the above analyses, the Authority is of the view that the 5-year term of a nominal risk free rate is appropriate. This 5-year term is adopted in the estimate of the MRP of 6 per cent and this term is also matched with the "NPV = 0" principles from refereed academic papers, which state that the term of a risk free rate should be equal with the term of a regulatory period. In addition, the Authority's analysis indicates that an average of a 5-year risk free rate has been consistently lower than the average of the 5-year term 20 trading day period during global crises. These crises were considered to be a key factor causing a low risk free rate as investors seek higher quality investments.

1402. As such, the Authority does not approve Western Power's revision in relation to the calculation of the nominal risk free rate of return using the 10-year term to maturity on the Commonwealth Government bonds.

1403. The Authority considers the estimated nominal risk free rate of return should be 2.52 per cent using yields from the 5-year Commonwealth Government bonds reported by the RBA, over the 20-business day period to 15 June 2012, the agreed averaging period between Western Power and the Authority.

Expected Inflation

Western Power's Initial Proposal

1404. Western Power proposed an estimate of the expected inflation based on the geometric mean over the 10-year period of:

- the CPI forecasts from the most recent Statement on Monetary Policy by the RBA; and
- the midpoint of 2.5 per cent for remaining years for which explicit forecasts by the RBA are not available.

1405. Using the May 2011 Statement on Monetary Policy, Western Power proposed to adopt the expected inflation rate of 2.70 per cent.[361]

Draft Decision

1406. Subject to the following discussion, the Authority's Draft Decision accepted Western Power's proposed method for calculating the forecast rate of inflation, but does not approve the use of a 10-year term to maturity.

1407. Western Power's proposed method calculates the expected inflation rate as the geometric mean of the RBA's inflation forecasts. The Authority was of the view that this method is widely used by Australian regulators and, as such, the Authority accepted the use of this method to calculate the expected inflation rate.

1408. However, the Authority considered that the term used should be 5 years, which is consistent with the term used to calculate the nominal risk free rate.

1409. The Authority adopted the same method as Western Power. However, the expected rate of inflation was calculated as a geometric mean of inflation forecasts by the RBA for the next two years and the mid-point estimate of the RBA's long-term inflation forecasts of 2.5 per cent for the remaining *three* years (rather than for the remaining eight years, as used by Western Power). The forecasts that the Authority relied on for its calculations in its Draft Decision are from the Reserve Bank of Australia's February 2012 *Statement on Monetary Policy:*[362]

- 1.75 per cent for the year to June 2012;

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[361] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 263-4.

[362] Reserve Bank of Australia, November 2011, *Statement on Monetary Policy*, available at http://www.rba.gov.au/publications/smp/2011/nov/pdf/1111.pdf p. 66.

- 3.25 per cent for the year to June 2013;
- 2.75 per cent for the year to June 2014; and
- 2.50 per cent (being a mid-point estimate of the Reserve Bank of Australia's long term inflation forecasts) for each year from June 2015.

1410. Using the above forecasts, the Authority calculated the forecast inflation rate for the Draft Decision of 2.55 per cent.

Western Power's response to the Draft Decision

1411. In response to the Draft Decision, Western Power has revised an estimate of the expected inflation rate based on the geometric mean over the 10-year period of:

- the CPI forecasts from the most recent Statement on Monetary Policy by the RBA, being May 2012; and
- the midpoint of 2.5 per cent for remaining years for which explicit forecasts by the RBA are not available.

1412. Using the May 2012 Statement on Monetary Policy, Western Power revised the expected inflation to 2.42 per cent.[363]

Final Decision

1413. In its submission in response to the Authority's Draft Decision, Western Power proposed a method of calculating the expected inflation rate as the geometric mean of the RBA's inflation forecasts. In its Draft Decision, the Authority was of the view that this method is widely used by Australian regulators and, as such, the Authority accepted the use of this method to calculate the expected inflation rate. However, consistent with the view taken in the Draft Decision, the Authority considered that the term used should be 5 years, which is consistent with the term used to calculate the nominal risk free rate.

1414. The Authority notes the real risk free rate derived by using Fisher's equation[364] is negative when the nominal risk free rate is estimated using linear extrapolation from 5-year CGS observed yields and the expected inflation rate is estimated using the geometric mean of the RBA's inflation forecasts.

1415. The Authority notes that the estimate of expected inflation using the RBA's forecasts assume an expected inflation rate of 2.5 per cent (the mid-point of the RBA's target range) for the last three years of the regulatory control period, being years 3, 4 and 5. Given the current economic environment, markets may have discounted this mid-point value.

1416. Another option is to derive the expected inflation rate from the Fisher equation using the estimates of a nominal risk free rate (using five year Treasury bonds as a proxy) and a real risk free rate (using Treasury's indexed CGS bonds as a proxy).

[363] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 263-4.

[364] The Fisher equation as proposed by Irving Fisher takes the form of $1+i=(1+r)(1+\pi)$ where i is the nominal interest rate, r is the real interest rate and π is expected inflation.

This was a practice adopted by the Authority and other Australian economic regulators, such as the AER, until 2008 when the Global Financial Crisis occurred and the market for Treasury indexed bonds experienced liquidity issues. The Authority notes that liquidity has been good by historical standards in both bond markets, based on correspondence with the Australian Office of Financial Management.[365] As such, the Authority is of the view that it is appropriate to derive expected inflation from nominal and real risk free rates of return. Linear interpolations of the five-year yields were used, based on the RBA's data to arrive at a 20 day average of Treasury Bond annualised yields and Indexed Bond annualised yields to derive the nominal and real risk free rates. These were then used to derive the expected inflation rate.[366]

1417. The Authority notes that this alternative method of calculating the expected inflation rate does not result in the use of negative real interest rates in the WACC calculation. In addition, the Authority considers that the market's expectations of inflation over the period may be more relevant to investors' pricing of debt than the method used to calculate inflation by the Authority in the Draft Decision, provided that the market is producing signals that could be considered efficient. This appears to be the case at present, given the advice to the Authority that indicates that the market for Treasury's indexed CGS bonds is sufficiently liquid.

1418. The application of the Fisher equation to the calculation of the inflation rate also ensures consistency between the real and nominal risk free rates used in the WACC calculation. On balance, the Authority considers that it is appropriate to calculate the forecast inflation rate by taking market observations of nominal and indexed CGS bonds and then applying the Fisher equation.

1419. For this Final Decision, the Authority has adopted an expected inflation rate of 2.10 per cent derived from Fisher's equation using estimates of the nominal and real risk free rates of return.

Capital Structure

Western Power's Initial Proposal

1420. Western Power did not propose any change to the 60 per cent gearing level (debt to total assets) assumed in the current access arrangement on the basis that it considered this to be an efficient capital structure for the AA3.[367]

Draft Decision

1421. The benchmark gearing ratio for the purpose of calculating a WACC is considered to be the capital structure of a benchmark efficient utility business. The Authority assumes that the regulated business tends towards the benchmark gearing level in the long-run. As the optimal level of gearing is not directly observable, the 60/40

365 Email and Telephone Correspondence with the Australian Office of Financial Management , 24 and 25 July 2012

366 The twenty trading days to 15 June 2012 for Treasury Bond TB120, TB135 and Treasury Indexed Bond TI405 and TI406 were sourced from the Reserve Bank of Australia's F16 statistical table. These bonds straddle the date of 15 June 2017.

367 Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 259.

gearing level is derived from the average of actual gearing levels from a group of comparable firms.[368] The actual proportion of debt and equity for each business is dynamic and depends on a number of business-specific factors.

1422. In the Draft Decision the Authority agreed that Western Power's proposed gearing level of 60 per cent is consistent with the approach taken in relation to the current access arrangement and the approach taken in the AER electricity WACC Review, as well as being otherwise consistent with regulatory precedent and with observed levels of gearing of Australian electricity and pipeline companies.

Public Submissions in response to Draft Decision

1423. WAMEU considers the gearing level does not reflect that of Government owned networks. They submit that the Authority has provided no evidence to support this assertion.[369]

Final Decision

1424. The Authority does not agree with WAMEU's submission on the issue. The Authority is of the view that the capital structure to be adopted in this Final Decision is the capital structure for a benchmark firm, not a capital structure that is specifically targeted to Western Power.

1425. The Authority approves Western Power's proposal that the appropriate debt to total assets ratio (gearing level) is 60 per cent and the equity to total assets ratio is 40 per cent.

Benchmark Credit Rating

Western Power's Initial Proposal

1426. Western Power proposed the adoption of a BBB+ credit rating assumption for a benchmark efficient firm. Western Power submitted that this benchmark credit rating has previously been adopted by the Authority and the AER.[370]

Draft Decision

1427. In the Draft Decision the Authority noted that the current approach of estimating the required rate of return or the WACC for Western Power's proposed access arrangement is to adopt the benchmark framework that is widely used by other Australian regulators. In this benchmark approach, the benchmark credit rating of BBB+ is used.

1428. Australian regulators have tended to use a target credit rating of BBB+ for the benchmark rate of return for their regulated energy businesses. However, due to

[368] Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters.

[369] Western Australia Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, April 2012, p. 24.

[370] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 261.

the limited number of Australian energy firms with credit ratings of BBB+ in the Australian financial market, regulators tend to include firms with credit ratings of BBB/BBB+ in the sample when using a benchmark credit rating.

1429. In its draft decision on the WACC Review released in December 2008, the AER considered a number of approaches to estimate the credit rating to be used when selecting the sample of bonds to estimate the debt margin, including median credit ratings, simple average credit ratings and Ordinary Least Squares (**OLS**) regressions. The AER examined data from 2002 to 2008 and found that:[371]

- private electricity businesses had a median credit rating of A-;
- gas networks had a median credit rating of BBB;
- private energy networks had a median credit rating of BBB+;
- government networks had a median credit rating of AA; and
- energy networks had a median credit rating of A-.

1430. In its WACC Review in 2009, the AER was of the view that the most appropriate approach to determining the credit rating of a benchmark efficient network service provider is the "median credit rating" of sample businesses, and the "best comparator".[372]

1431. As a consequence, the AER proposed an increase in the target credit rating used in the estimation of the debt margin, from BBB+ to A-. The AER argued that there is sufficient evidence to increase the benchmark credit rating from BBB+ to A-. The AER based its analysis on:

- the S&P ratings process, which indicates that qualitative factors in the regulated utilities ratings process result in credit ratings higher than BBB; and
- the quantitative analysis of credit ratings of a sample of utility-issued debt that was considered by the AER.

1432. However, in its Final Decision released in May 2009, the AER changed its view from the Draft Decision on the benchmark credit rating. The AER noted that:[373]

> "The AER observes that these different techniques provide a range of credit ratings from BBB+ to A-. The AER considers there is ***more evidence to support a credit rating of A-*** than there is to support a credit rating of BBB." [emphasis added].

1433. Notwithstanding this, after considering the submissions it received on its Draft Decision, the AER was not persuaded at that time that the previously adopted credit rating of BBB+ should be departed from.

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371 Australian Energy Regulator, December 2008, *Explanatory Statement, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

372 Australian Energy Regulator, May 2009, Final Decision*, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

373 Australian Energy Regulator, May 2009, Final Decision*, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* p. 389.

1434. The AER's analysis (as shown in Table 153) demonstrated that the median credit rating remained constant, irrespective of the period selected between 2002 and 2008. Further, it is clear that the median credit rating is A- for both the private electricity sample and the energy businesses in the sample.

Table 153 Comparison of Different Samples (2002-2008)

Measure	Energy Networks	Government Energy Networks	Private Energy Networks	Private Electricity Networks
Median Credit Rating (Excluding hybrids)	A-	AA	BBB	A-
Median Credit Rating (Hybrids businesses)	A-	AA	BBB+	A-
Number of businesses (Excluding hybrids)	7-10	1-4	5-10	3-5
Number of businesses (Hybrids businesses)	11-15	3-6	7-12	6-8
Government networks (%)	31	81	10	14
Private electricity (%)	41	15	54	77
Electricity (%)	68	83	61	87

Source: AER, December 2008, Table 9.4, page 270.

1435. The Authority's final decision in relation to Western Power's current access arrangement in December 2009 noted that the AER applied a credit rating of BBB+ in its WACC review in 2009, which took into account capital market evidence that would support a credit rating assumption in the range of BBB+ to A-. However, the Authority was required to apply a credit rating of BBB+ from its WACC review on 25 February 2005, which applied until 25 February 2010 for the assessment of Western Power's current access arrangement.[374] As such, in its final decision in December 2009, the Authority assessed Western Power's proposed WACC on the basis of an assumed credit rating of BBB+.

1436. Table 154 below presents an updated credit rating for Australian energy companies as at December 2011. This was prepared prior to the Authority publishing the Draft Decision in March 2012.

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374 Economic Regulation Authority, 25 February 2005, *Determination of the preferred methodology for calculating the weighted average cost of capital for covered electricity networks*.

Table 154 Standard & Poor's Credit Rating for Australian Energy Companies, December 2011

Company	Current Rating by S&P	Comments
AGL	A-	
Alinta	BBB	[Discontinued, last on 15/9/04]
Alinta Network	BBB	[Discontinued, last on 15/9/04]
Country Energy	AA-	Aa3 by Moody
DUET	BBB-	
ElectraNet Pty Ltd	BBB	
Energy Australia	*N/A*	
Envestra Ltd	BBB-	
Ergon Energy Corporation	AA	
ETSA Utilities	A-	
Integral Energy	AA-	Aa3 by Moody
GasNet	BBB	
SPI PowerNet	A-	
SP AusNet Group	A-	

Source: Bloomberg

1437. The Authority is of the view that the companies in Table 154 are sufficiently close comparators to the efficient benchmark network service provider. This was also the AER's view in its final decision on the 2009 WACC Review.[375]

1438. The "median credit rating" approach in the AER's WACC Review in 2009 shows that the median credit rating of the sample of Australian energy businesses is A-. This is the same credit rating as for a sample of Australian privately owned electricity businesses.[376]

1439. The Authority updated the AER's analysis above for its Draft Decision released in March 2012. The Authority was informed by this updated analysis that A- is the median credit rating for the sample of Australian energy businesses.

1440. The Authority also noted that the stand-alone credit rating for Synergy, an electricity retailer in Western Australia, is A+ by S&P in 2010.[377]

1441. Based on the above analyses, the Authority took the view that the evidence currently available to it indicates that the benchmark credit rating for network service providers as at December 2011 was A-.

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[375] Australian Energy Regulator, May 2009, Final Decision, *Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 380-1.

[376] Australian Energy Regulator, December 2008, *Explanatory Statement, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

[377] Standard & Poor's, Global Credit Portal, RatingsDirect, Synergy, 23 September 2010, p. 8

Relevance to Western Power of the WA State Government Credit Rating

1442. In the Draft Decision, the Authority noted that many public submissions to the first round of public consultation stated that the appropriate credit rating for Western Power should be the same as the credit rating for the State Government of Western Australia, being AAA as at December 2011. As a consequence, the cost of debt incurred by Western Power is the actual cost of debt charged by the Western Australian Treasury Corporation (**WATC**).

1443. However, the Authority took the view that there is no compelling reason to depart from the credit rating for the efficient benchmark network service provider, which is A- as at December 2011, for the following reasons:

- The State Government's credit rating reflects its power to take recourse against its taxpayers. Western Power's cost of debt should reflect the level of risk inherent in its operations. The difference in the cost of debt to Government and Western Power acts as a premium on credit insurance for taxpayers in the event that Western Power defaults. Eliminating this premium through providing debt to the service provider at the State Government's rating leaves taxpayers uncompensated against the risk of a default.
- A credit rating established independent of ownership is required to maintain competitive neutrality. Agencies borrowing from the Government should thus face interest rates equal to a private sector rate; that is, Western Power's cost of debt should not be lowered to reflect the benefit of Government ownership and should instead be commensurate with the risks Western Power would face were it privately owned.
- A credit rating that is inconsistent with market outcomes distorts investment decisions in upstream and downstream markets. Investment decisions made in those markets would be undertaken as a result of artificially low or high prices stemming from an artificial credit rating and lead to inefficient investment.
- A rating that is inconsistent with efficient market outcomes also creates the potential for the network service provider to undertake inefficient levels of capital investment. That is, it results in over-investment if the rating is too low. The WACC must accurately reflect the level of risk embodied in the network service provider's operations in order to constrain the potential for inefficient investment.

1444. In summary, the Authority was of the view that it is inappropriate to assign a credit rating of AAA for Western Power for the purpose of estimating the cost of capital for this business.

1445. The Authority's Draft Decision was based on the assumption that the level of risk faced by electricity transmission and distribution firms is the same across Australia. As such, using the benchmark rate of return will ensure that Western Power is treated the same as its "directly comparable" businesses from other states of Australia.

1446. For the reasons set out above, in the Draft Decision the Authority did not approve Western Power's proposal in relation to the credit rating of BBB+ and took the view that the appropriate credit rating for a network service provider was A-.

Western Power's Response to the Draft Decision

1447. In response to the Draft Decision, Western Power submitted that its most appropriate credit rating is BBB. This view is based on the following two observations:

- Western Power's own quantitative analysis; and
- the advice of Western Power's consultant (CEG) on the issue of credit rating and the cost of debt, which indicated that the sample on which the Authority has relied to determine the credit rating of A- for Western Power is in error.

1448. Each of these two arguments is outlined in turn below.

Western Power's Own Quantitative Analysis

1449. In response to the Authority's Draft Decision with regard to the benchmark credit rating of A-, Western Power submitted that it has undertaken a quantitative analysis using the key credit rating metrics by S&P to assess whether the generated cash flows are sufficient to attract an A- credit rating. Western Power concludes that its best possible credit rating is BBB[378].

The sample of Australian businesses relied on by the Authority

1450. CEG submits that, in deriving the credit rating of A- for Western Power in the Authority's Draft Decision, the Authority erred in relation to the following points:[379]

- An incorrect rating assigned to AGL in the sample. CEG submitted that the credit rating for AGL is BBB.
- Inclusion of Australian state-supported credit ratings. CEG argued that three regulated businesses supported by Australian state governments being Ergon Energy, Endeavour Energy (previously Integral Energy) and Essential Energy (previously Country Energy), should not be included in the sample.
- Inclusion of foreign-supported credit ratings. CEG submitted that SPI PowerNet and SP AusNet (owned by the Singapore Government) should not be included in the sample.
- Reference to Synergy's credit rating. CEG argued that Synergy is not engaged in the provision of energy network services that are covered in the Access Code. As such, this reference is not relevant.

1451. Using its analysis and the advice of its consultant, Western Power concluded, given the Authority's Draft Decision, Western Power would attract a credit rating below BBB over the third access arrangement period. As such, Western Power argued that a credit rating of BBB would be a best case scenario.[380]

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[378] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision.

[379] Competition Economists Group, 2012. *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 6-8.

[380] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, pp. 151-2.

Public Submissions to the Draft Decision

1452. WAMEU considered the Authority's cost of debt in the WACC to be high in the sense that it does not reflect Western Power's actual funding arrangements with WATC. It submitted that the Authority has provided no logical justification for this.[381]

1453. WACOSS considers that Western Power's credit rating should be A+ or AA. It supports a formal credit rating of Western Power by an independent credit agency as an input to determine an appropriate credit rating for Western Power. It considers it significant that Synergy was rated A+ by an independent rating agency. WACOSS notes that Western Power's revenues are much more predictable than Synergy's and supported the use of an appropriate comparator group of power companies to estimate Western Power's credit rating. It considers that a comparator group should be made up of publicly-owned energy network companies.[382]

1454. Alinta Energy considers that a key consideration should be that the rate of return incentivises Western Power to move towards the efficiency frontier for network services providers. It believes a WACC specifically targeted at Western Power's ownership structure and actual access to financing is a short term solution and is likely to result in detrimental outcomes for consumers of electricity in the long term.[383] As such, a benchmark credit rating appears to be appropriate for a determination of the rate of return for Western Power's access arrangement.

1455. Grid Australia observes that Government owned businesses are better able to maintain higher credit ratings and/or issue shorter term debt than are stand alone businesses because of the expectation that tax payers will bail out a failed entity. It notes that if the Authority takes account of this implicit guarantee when setting prices, then those prices will not reflect the full economic cost and will amount to a subsidy. It further notes that, to treat a government owned entity differently to a privately owned entity is not consistent with commitments to competitive neutrality. Grid Australia also observes that credit ratings for comparator firms are boosted either by implicit government guarantees or as a result of the entity being part of a larger corporate group that is considered supportive. Abstracting from this, it is of the view that the highest credit rating of the comparable entities is BBB.[384]

1456. Horizon Power raises concerns regarding the increase in the benchmark credit rating to A- when BBB+ has been adopted nationally and submits that this increase has not been fully explained by the Authority.[385]

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[381] Western Australia Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, April 2012, p. 4.

[382] Western Australian Council of Social Service Inc, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 14.

[383] Alinta Energy, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 2.

[384] Grid Australia, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 8.

[385] Horizon Power, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 3.

1457. Energy Networks Association raised concerns that the observation of a stand-alone credit rating for Synergy does not provide sufficient evidence to justify the adoption of a higher credit rating (A-) for the estimation of the debt risk premium.[386]

Final Decision

1458. For convenience, submissions by the interested stakeholders such as the WAMEU, WACOSS, Alinta, Grid Australia and Alinta Energy and by Western Power and its consultants are addressed in separate sections.

Responses to Public Submissions

1459. In its Draft Decision released in March 2012, the Authority concluded that the benchmark credit rating is to be adopted in the Western Power's Access Arrangement. The Authority also indicated that it is inappropriate to adopt Western Power's stand-alone credit rating or that of the State Government for Western Power's access arrangement.[387] As a result, the Authority does not agree with the submission by WAMEU and WACOSS supporting the adoption of a credit rating that is not the benchmark credit rating for a regulated business as a network service provider.

1460. The Authority agrees with Alinta Energy that a credit rating which specially targets Western Power's ownership structure and its actual funding via the WATC, would not result in a reasonable outcome for the benefits of the consumers of electricity in the long run.

1461. The Authority notes that Grid Australia, Horizon Power and Energy Networks Association do not agree with the Draft Decision with respect to the use of A- for Western Power. All these organisations are of the view that the benchmark credit rating of A- applied to Western Power's Access Arrangement is not appropriate and that the credit rating of BBB+, which is lower than A-, is appropriate. The Authority considers that these organisations did not provide any substantive evidence to support their views that a lower credit rating compared with A- would be appropriate for Western Power.

Responses to Western Power and its Consultant's Submissions

Western Power's Own Quantitative Analysis

1462. The Authority acknowledges that credit rating agencies such as S&P use the credit metrics, as presented by Western Power, to assess the credit ratings of their clients. However, this assessment is only one component of the entire credit rating process. S&P indicates that qualitative information has played a significant role in the process of assessing the credit rating for an agency.[388]

1463. The Authority notes that its approach to determining the credit rating for a regulated business is based on a "benchmark" company, not specifically for Western Power.

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[386] Energy Networks Association, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 4.

[387] The Economic Regulation Authority, 2012, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, March 2012, p. 175.

[388] Discussions with Standard and Poor's Capital IQ representatives 17 July 2012.

As such, Western Power's analysis of its own credit rating is not suitable for this purpose. If Western Power is assessed based on its own financial circumstances, then the credit rating for the State Government of AAA should also be the credit rating for Western Power because that is the credit rating Western Power uses to borrow funds from the financial markets via the WATC. As such, the Authority is of the view that Western Power's analysis using its own cash flows is not appropriate.

1464. However, for completeness, the Authority notes that there are different definitions of the accounting equations defined in the S&P's credit metrics. For example, the concept of Funds from Operation (**FFO**) can be defined as net income (computed in accordance with generally accepted accounting principles), excluding gains (or losses) from sales of property, plus depreciation and amortization, and after adjustments for unconsolidated partnerships and joint ventures.[389] Western Power did not clarify the definitions it adopted for assessing the S&P's credit metrics. As such, the Authority is unable to verify the validity of its analysis.

1465. Standard and Poor's use the following matrix,[390] as presented in Table 155, as part of its credit rating methodology.

Table 155 Standard and Poor's Risk Profile Matrix

Business and Financial Risk Profile Matrix						
Business Risk Profile	*Financial Risk Profile*					
	Minimal	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	-
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	-	BBB-	BB+	BB	BB-	B
Weak	-	-	BB	BB-	B+	B-
Vulnerable	-	-	-	B+	B	CCC+

Source: S&P 2009

1466. As part of the financial risk profile assessment, S&P presented the following table, Table 156, accommodating a basic example to help improve understanding of its rating process.

[389] National Association of Real Estate Investment Trusts Inc, 2002, *White Paper on Funds From Operations*, April 2002.

[390] The Authority notes that the debt risk premium incurred by WATC is approximately one per cent.

Table 156 Standard and Poor's Example Financial Risk Indicative Ratios Table

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leverage	less than 12	greater than 5	greater than 60

Source: S&P 2009

1467. In practice S&P uses a more comprehensive list of categories on which it bases its assessment of financial risk, which includes: accounting; financial governance and policies/risk tolerance; cash flow adequacy; capital structure/asset protection; and liquidity/short-term factors. Furthermore, its assessment also incorporates business risk, including: country risk; industry risk; competitive position; and profitability/peer group comparisons.

1468. The Authority considers that it is not S&P's intention that the criteria supplied in Table 156 alone be used to understand the rating of a company. For example, if we take the Queensland Government owned energy business Ergon as an example, its financial indicators are classified as minimal for its cash flow to debt ratio (FFO/Debt), which is 61 per cent, and intermediate for its debt to EBITDA ratio (Debt/EBITA), which is 2.3 times; and proportion of debt funding (Debt/Capital), which is 43 per cent.

Table 157 Ergon's Financial Indicators, 2012

Items/Financial Indicators	Ergon ($ million)	Powercor/Citicorp ($ million)
Interest Bearing Liabilities		
Current	19.9	7.5
Non-Current	4,314.7	4,966.4
	4,334.6	**4,973.9**
Cash Flows From Operating Activities		
Receipts From Customers	2,611.7	1,210.9
Interest Received	20.6	77.0
	2,632.3	1,287.9
FFO/Debt	61%	26%
Revenue	2,528.1	1,208.7
Other Income	10.4	0.794
Employee Expense	-214.7	-753.548
Materials and Services	-215.3	
Other Expense	-204	
EBITDA	**1,904.5**	**456.0**
Debt/EBITDA	**2.3**	**10.9**
Total Assets	9,974.9	6,322.1
Debt	4,334.6	4,973.9
Debt/Capital	**43%**	**79%**

Source: Ergon's and Citicorp/Powercor's Financial Statements, 2012 and the ERA's analysis

1469. This limited set of indicators and an assumption of an excellent business risk profile would rate Ergon somewhere in between a credit rating of AA and A. A more comprehensive assessment as outlined by S&P is required to better determine the financial risk classification, while an assessment of business risk is required in order to classify the business risk profile. The Authority notes that a downgrading of business risk from *excellent* to *strong* would result in this simplistic rating falling somewhere in between A and A-. The S&P credit rating, taking into account both business risk and financial risk, for Ergon is AA.

1470. Another illustration is applied to Powercor/Citipower. Using publicly available financial data reported from its financial statements, the Authority calculated the set of financial indicators, as presented in Table 157 above, for these consolidated companies. Assuming that the business risk for Powercor/Citipower is *excellent*, together with the financial risks as indicated by the set of financial indicators, the Authority is of the view that the credit rating of Powercor/Citipower is at best BBB.

However, the Authority notes that Powercor/Citipower is rated with the credit rating of A- by the S&P.

1471. The Authority is not aware of the S&P definitions for the accounting equations used in its credit metrics. This, combined with the fact that credit metrics only play a partial role in the entire credit rating process by S&P and the example of Ergon, results in the Authority concluding that the S&P credit rating process is much more complex than a simple calculation of some financial indicators as Western Power has submitted. The Authority considers that Western Power has not provided any convincing evidence to support its view that the credit rating of BBB should be considered as the best case scenario for Western Power.

The sample of Australian businesses relied on by the Authority

1472. The Authority does not agree with Western Power and its consultant CEG in relation to the exclusion of some companies from the sample. The Authority is of the view that it is more appropriate to include all companies operating in the utilities sector in the sample regardless of their ownership to determine the benchmark credit rating. The Authority considers that a wider sample of companies will present a better proxy for a benchmark credit rating for a network service provider. This practice is consistent with the rationale for the development of the Authority's bond-yield approach in December 2010.

The Authority's updated analysis

1473. The Authority obtained the most recent credit ratings for all Australian rated utilities as summarised from Bloomberg. The Authority is of the view that including all companies in the same industry is appropriate for the determination of the benchmark credit rating.

Table 158 Standard & Poor's Credit Rating for Australian Energy Companies, August 2012

Issuer	Latest Rating	Effective Date	Rating Type
Ergon Energy Corporation	AA	20/02/2009	Long Term Local Currency Issuer
ElectraNet	AA-	30/11/2011	Instrument
Energy Partnership (Gas) Pty Ltd	AA-	30/11/2011	Instrument
Envestra Ltd	AA-	30/11/2011	Instrument
Citipower	A-	9/11/2010	Instrument
ETSA Utilities	A-	28/02/2009	Instrument
Powercor Australia	A-	24/06/2009	Instrument
Rowville Transmission Facility Pty Ltd	A-	28/02/2012	Long Term Senior Secured Debt Rating
SPI PowerNet Pty Ltd	A-	31/03/2008	Long Term Local Currency Issuer
Country Energy (now Origin)	BBB+	31/03/2011	Long Term Local Currency Issuer
United Energy	BBB	3/04/2012	Instrument
AGL Energy Ltd	BBB	24/02/2012	Long Term Local Currency Issuer
DUET	BBB-	3/06/2003	Long Term Local Currency Issuer

Source: Bloomberg

1474. Table 158 shows that, out of the sample of 13 companies classified as Australian energy companies, there are five with a credit rating of A-, which are shaded in the above table. The median credit rating for the entire sample lies within the companies with an A- credit rating, including Citipower, ETSA Utilities, Powercor Australia, Rowville Transmission Facility, and SPI PowerNet. As such, the Authority is informed by this updated analysis that A- is the median credit rating for the sample of close comparators, as presented in Table 158 above.

1475. The Authority is aware that some of the above credit ratings are for instruments of the entities, not for the entities as a whole. It is also aware that credit wrapping (enhancement) or insurance may have been used to improve the credit rating of the businesses. However, the Authority considers that achieving a better credit rating using credit wrap and/or insurance will incur a cost that is not publicly available to quantify. Among five companies with a credit rating of A-, two companies Citipower and Powercor both have the same credit rating of A- for their entities and their financial instruments. As such, a credit rating of A- is applied for both the entities level and the instruments level. The Authority is of the view that it is more appropriate to base its decision of a benchmark credit rating on the entities' credit rating.

1476. In its WACC Review in 2009, the AER was of the view that, the size of the sample of businesses and the likelihood that a robust estimate can be obtained must be taken into account.[391] In addition, the AER also considered that including both subsidiaries and their parents introduces an issue of double counting. Given the number of mergers and acquisitions that have taken place since the AER's credit rating analysis, the Authority is of the view that it is appropriate to exclude parents of subsidiaries in the sample and only include the subsidiaries themselves. This is in order to keep the sample as large as possible whilst avoiding double counting.[392] The AER found it was unlikely for the majority of the subsidiaries in the sample to have been rated in such a way that their financial positions were ignored.[393]

1477. Using all of S&P's available industry reports for Australian electricity network service providers from 2008 to 2011 inclusive, the Authority considers that it is appropriate to conclude that a median credit rating of A- is observed from the sample of 12 Australian electricity network service providers (Table 159 Table 159).[394] It must be noted that Ausgrid and Essential Energy were not included in the calculation because S&P credit ratings were not available for them.

Table 159 S&P Credit Rating, 2008 – 2011

Electricity Network Service Providers Standard and Poor's Issuer Rating					
Company/Year	**2008**	**2009**	**2010**	**2011**	**Entity's Median Credit Rating**
Ergon Energy Corp Ltd	AA+	AA	AA	AA	**AA**
CitiPower I Pty Ltd	A-	A-	A-	NA	**A-**
Powercor	A-	A-	A-	A-	**A-**
ETSA Utilities Finance	A-	A-	A-	A-	**A-**
SPI Australia Assets Pty Ltd	A-	A-	A-	A-	**A-**
Jemena Ltd	A-	NA	A-	A-	**A-**
United Energy Distribution Pty	BBB	BBB	BBB	BBB	**BBB**
ElectraNet Pty Ltd	BBB+	BBB+	BBB	BBB	**BBB/BBB+**
Ausgrid	NA	NA	NA	NA	**NA**
Essential Energy	NA	NA	NA	NA	**NA**
Integral Energy (Origin now)	BBB+	BBB+	BBB+	BBB+	**BBB+**
Sample Median	**A-**	**A-**	**A-**	**A-**	**A-**

Source: S&P and the Economic Regulation Authority's analysis

391 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 109.

392 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 379.

393 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 368.

394 See Standard and Poor's, 2011, *Industry Report Card: Australian Utilities Are On A Firm Footing, But Confronting Regulatory Reviews*, 21 November 2011, pp. 9-12; Standard and Poor's, 2010, *Industry Report Card: Refinancing And Balance Sheet Management Remain Top Of The Agenda For Australian Utilities*, 5 May 2010, pp. 7-10; Standard and Poor's, 2009, *Industry Report Card: For Australian Utilities, The Challenge Remains To Manage Refinancing And Balance Sheets*, 7 May 2009, pp. 7-10; and Standard and Poor's, 2008, *Industry Report Card: Australian Utilities' Credit Prospects Dimmed By Looming Shadow Of M&A, Climate, And Regulatory Risks*, 9 May 2008, pp. 8-20.

Conclusion

1478. The Authority notes that A- is the median credit rating obtained from both the sample of Australian energy businesses (as shown in Table 158) and the sample of electricity network service providers (as shown in Table 159).

1479. The Authority is conscious that a decision to adopt a benchmark credit rating of A- for an electricity network service provider in Australia would be a departure from the AER's current approach of applying a credit rating of BBB+.

1480. The Authority notes that the AER, in its WACC Review in 2009, used S&P industry report cards for the period from 2002 to 2008 to identify that the median credit ratings for private electricity networks and government energy networks were A- and AA respectively.[395] In addition, the AER considered data from a sample of best comparators to identify that, based on this approach, the median credit rating was BBB+.[396] Overall, the AER was not persuaded at that point in time to depart from the previously adopted credit rating of BBB+.

1481. The Authority notes that a median credit rating of A- is observed from the sample of Australian energy businesses in which some credit ratings are applied to the instruments of the entities, rather than the entities. The Authority is of the view that firms are likely to be incurring costs to obtain credit ratings for their instruments that are higher than can be achieved for the entity. The Authority therefore considers it appropriate, at this time, to include firms with a credit rating of BBB+ in the benchmark sample used by the Authority to estimate the debt risk premium.

1482. Current regulatory practice in Australia is to use firms with credit ratings of BBB and BBB+ when estimating the debt risk premium based on a benchmark credit rating of BBB+. The main rationale for this practice is to ensure that there are sufficient Australian corporate bonds in the sample to estimate the debt risk premium. It is understood that Bloomberg's estimate of the Australian fair value curve for 7-year BBB credit rating also includes bonds with the credit rating of BBB+ in its underlying sample.

1483. Overall, in deciding on an appropriate credit rating, the Authority has given weight to the median credit rating of A-, as observed in the samples of Australian energy businesses and electricity network service providers. However, the Authority notes that applying a credit rating of A- would be a departure from the current regulatory practice as applied by the AER. The Authority is also aware of the costs that may be being incurred by energy businesses in obtaining higher credit ratings for their instruments. Therefore, for the purpose of this Final Decision the Authority has decided to include all Australian corporate bonds with a credit rating of A-, BBB+, and BBB in the benchmark sample for the Authority's bond-yield approach to estimate the debt risk premium as at 15 June 2012 as agreed with Western Power.

[395] Australian Energy Regulator, December 2008, Draft Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 284.

[396] Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 394.

Debt Risk Premium

Western Power's Initial Proposal

1484. Western Power submitted its arguments in response to the Authority's Discussion Paper on "*Measuring Debt Risk Premium: A Bond-Yield Approach*", released in December 2010.[397]

1485. Western Power also submits that adopting a borrowing term of less than 10 years will underestimate the debt risk premium applicable to an infrastructure business.[398]

1486. Western Power also cites the decision of the ACT in an appeal from the AER's decision on Jemena Gas Networks to argue that Bloomberg's estimates of fair value curves for Australian corporate bonds are widely used and market respected.[399]

1487. Western Power proposes that a debt risk premium should be estimated using the following two methods:[400]

- extrapolating the 7-year Bloomberg estimate of the fair value curve using the spread between Bloomberg's 10-year AAA and 7-year AAA fair value curves over the last 20 trading days to 22 June 2010, (which is when these estimates were last available); and
- extrapolating the 7-year Bloomberg estimate of the fair value curve using the spread between 10-year and 7-year Commonwealth Government Securities as a proxy for Bloomberg's AAA rated bonds over the averaging period commencing on 4 May 2011 and ending on 31 May 2011.

1488. Using the above two methods to estimate a debt risk premium, Western Power proposes that the estimated debt risk premiums over the period from 4 May 2011 and 31 May 2011 are within the range of 3.83 per cent and 4.30 per cent.[401]

Draft Decision

1489. The Authority considered each of the issues raised in Western Power's submissions as set out below.

Issues in Response to the Authority's Discussion Paper on the Bond-Yield Approach

1490. Issues raised by Western Power and in other public submissions received in response to the Discussion Paper have been discussed in detail in the Final

[397] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 262.

[398] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 262.

[399] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[400] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[401] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

Decision on Western Australia Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems, released in 28 February 2011.[402]

1491. The AER recently decided to stop using Bloomberg's estimates of the 7-year fair value curve in its decisions released in November 2011.[403] The AER was of the view that Bloomberg's 7-year fair value curve should be excluded from the sample to estimate the debt risk premium, for the following reasons.

- Bloomberg's estimates of fair value curves are derived using a proprietary methodology that is neither transparent nor verifiable. In addition, in a letter from Bloomberg to the AER dated 28 October 2011, Bloomberg stated that estimates of fair value curves are not a predictive source of price information.
- Bloomberg's estimate of the 7-year BBB fair value curve (the longest BBB rated fair value curve currently published) does not currently reflect available market evidence for long-dated bonds, or the stated views of other independent market commentators.
- Bloomberg's estimate of the 7-year BBB fair value curve does not reflect the prevailing cost of debt for the benchmark Australian corporate bond.

A Borrowing Term of Less than 10 Years

1492. The Authority is of the view that there is no evidence to suggest that regulated businesses will seek to issue long term debt as a matter of preference. Instead, the Authority is aware that some regulated businesses issue debt over a period of less than 5 years.

1493. The Authority is aware that regulated businesses generally avoid the situation of having a significant proportion of their debt funding maturing in any one year. In doing so, the businesses reduce their refinancing risks, as not all debts will reach maturity in the same year.

1494. The Authority has examined the debt profile[404] of energy network businesses in Australia. Data on the debt maturity profiles of relevant energy businesses in Australia was obtained from the 2010 annual reports which were publicly available.[405]

1495. Table 160 below shows that, in the sample of privately owned Australian energy networks, 52.5 per cent of total debt instruments have an average term of 5 years or less.

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402 This decision is available at: www.erawa.com.au/3/1076/48/wa_gas_networks_formerly_alintagas_distribution_sy.pm

403 The Australian Energy Regulator, 2011, Draft Decision, Powerlink Transmission Determination, 2012/13 – 2016/17, November 2011, pp. 218-9.

404 Debt instruments used for funding requirements include bank loans, debentures, commercial papers, syndicated bank debts, medium term notes and (both secured and unsecured) senior notes. Liquidity management policies ensure that the energy businesses have diversified portfolios, in terms of maturity and sources, which reduces reliance on any one source of funding in any particular year.

405 The Authority uses the same sample of businesses that Deloitte used in the advice for the AER on "Refinancing, Debt Markets and Liquidity" in 2008.

Table 160 Debt Profiles for Privately Owned Energy Network Businesses

Business	Amount of Debt by Average Term			Total Amount ($ millions)
	Less than 1 year	1 to 5 years	More than 5 years	
APA Group	250	800	1,368	2,418
ETSA Utilities, SA	495	1,375	2,489	4,359
Envestra	408	905	1,049	2,362
SP Ausnet	1,403	4,042	3,902	9,347
CitiPower and Powercor, VIC	906	2,212	2,769	5,887
Total	**3,462**	**9,334**	**11,577**	**24,373**
Per cent of total (%)	**14.20**	**38.30**	**47.50**	**100.00**

Source: 2010 Annual Reports and the Authority's analysis.

1496. The Authority is aware that interest rate swap contracts are normally used by privately owned energy networks to exchange floating interest amounts for fixed interest amounts. In doing so, regulated businesses can reduce their floating cash flow risk exposure, which results from floating rates on borrowings. Regulated businesses normally borrow actual or synthetic floating rate debts and then fix the interest rate for the term of the reset period, which is usually 5 years, using interest rate swaps.[406]

1497. The Authority also examined the debt profile of government-owned energy networks in Australia. Table 161 below shows that, in the sample of government-owned energy networks in Australia, approximately 44 per cent of total debt instruments have an average term of 5 years or less.

[406] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, pp. 101-109.

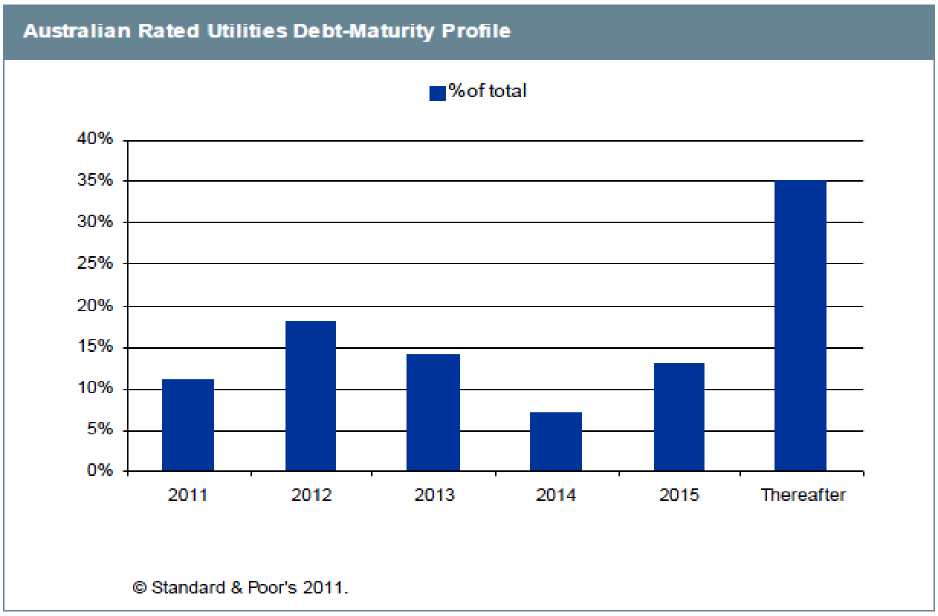
Table 161 Debt Profiles for Government Owned Energy Network Businesses

Business	Amount of Debt by Average Term			Total Amount ($ millions)
	Less than 1 year	1 to 5 years	More than 5 years	
Energex, QLD	464	1,129	4,027	5,620
Ergon Energy, QLD	1,273	1,323	3,966	6,562
Powerlink, QLD	283	852	3,439	4,574
Transend Networks, TAS	0	518	0	518
Horizon Power, WA	224	418	776	1,418
Western Power, WA	1,583	2,785	1,344	5,712
TransGrid, NSW	555	1,067	1,753	3,375
Power and Water Corporation, NT	4	134	766	904
Total	**4,386**	**8,226**	**16,071**	**28,683**
Per cent of total (%)	**15.29**	**28.68**	**56.03**	**100.00**

Source: 2010 Annual Reports and Authority's analysis.

1498. In addition, S&P's reports indicate that the debt maturity profiles of Australian rated utilities have generally been less than 5 years. Figure 12 presents the findings for the most recent year (2011). The Authority notes that the same conclusion is reached by analysing data from previous years.

Figure 12 Australian Rated Utilities Debt Maturity Profile



The ACT's Decision

1499. It appears that Western Power, in its proposal to adopt Bloomberg's estimate of a 7-year BBB fair value curve in the calculation of a debt risk premium, has incorrectly applied the ACT's decision mentioned in paragraph 1486 above. The ACT decision concerned the correctness of the AER's choice between CBASpectrum or Bloomberg. Even though the ACT's decision was made and publicly released in 2011, the decision related to an issue arising in 2010, which was before CBASpectrum decided to cease its estimates of fair value curves for all Australian corporate bonds (on 8 September 2010). The cessation of CBASpectrum estimates of fair value curves for Australian corporate bonds was one of the key factors for the Authority developing and releasing its own method of estimating the debt risk premium in December 2010. As a result, the Authority does not believe that the ACT's decision is relevant to its decision.

1500. In addition, in the Authority's consideration of the bond-yield approach for estimating a debt risk premium, the Authority concluded that Bloomberg's estimates of the fair value curves for Australian corporate bonds across different terms to maturity have become increasingly outdated.

Methods Proposed by Western Power to Estimate the Debt Risk Premium

1501. As discussed in its Discussion Paper on "Measuring Debt Risk Premium: A Bond-Yield approach" released in December 2010, the Authority is of the view that there are issues with:

- Bloomberg's estimates of fair value curves for BBB+ Australian corporate bonds with longer terms to maturity of 7 years and 10 years; and
- extrapolation from a 7 year term to a 10 year term.

1502. In addition, the Authority notes that extrapolation from a 7 year term to a 10 year term is no longer a method used by any Australian regulator. The AER, in its Draft Decision on Powerlink Transmission Determination released in November 2011, has moved away from using Bloomberg's estimates of the fair value curves for Australian corporate bonds.[407] In that decision the AER estimated the bond yields based on a sample of corporate bonds, using a methodology similar to the bond yield approach.

1503. The Authority therefore maintains its position that extrapolation of fair value curves from a 7-year term to a 10-year term to derive the debt risk premium is problematic and should not be relied on.

1504. The Authority considers that the two methods proposed by Western Power are problematic and that they should not be used to derive the debt risk premium.

Estimating the Debt Risk Premium: A Bond-Yield Approach

1505. The Authority is of the view that the bond-yield approach is appropriate for estimating the debt risk premium for Western Power's proposed revised access

[407] The Australian Energy Regulator, 2011, Draft Decision, Powerlink Transmission Determination, 2012/13 – 2016/17, November 2011, pp. 215-9.

arrangement. Under that approach, the Authority directly observes bond yields for a sample of companies in the Australian financial market.

1506. The Authority has used this approach in its final decisions on Western Australia Gas Networks Access Arrangement released in February 2011 and on the Dampier to Bunbury Natural Gas Pipeline Access Arrangement released in October 2011. This approach was endorsed in principle by the ACT in review applications relating to those access arrangements although the ACT required changes to the averaging process used by the Authority in those determinations.[408] The Authority proposes to use the same approach for Western Power's access arrangement.

1507. Table 162 below summarises a benchmark sample of Australian corporate bonds with the S&P credit rating of A- as at 29 February 2012.

[408] Australian Competition Tribunal, 2012, *Application by WA Gas Networks Pty Ltd (No 3) [2012] ACompT 12*, 8th June 2012, paragraph 179, p. 43.

Table 162 A Benchmark Sample of Australian Corporate Bonds with Credit Rating of A- (A Minus) as at 29 February 2012.

Number	Bond	Bloomberg Ticker	Coupon (Per cent)	Maturity
1	AUST & NZ BANKING GROUP	EG230753 Corp	6.50	5/03/2017
2	AUST & NZ BANKING GROUP	EG919776 Corp	7.75	18/10/2017
3	AUST & NZ BANKING GROUP	EJ031088 Corp	7.21	20/06/2022
4	COMMONWEALTH BANK AUST	EG461026 Corp	6.75	25/05/2017
5	POWERCOR AUSTRALIA LLC	EI601137 Corp	4.67	15/01/2022
6	COCA-COLA AMATIL LTD	EI545036 Corp	6.13	30/05/2014
7	COCA-COLA AMATIL LTD	EI963715 Corp	4.88	1/02/2017
8	COCA-COLA AMATIL LTD	EI814473 Corp	5.95	27/09/2021
9	COMMONWEALTH PROP FUND	EI060572 Corp	5.25	11/12/2016
10	MERCEDES-BENZ AUSTRALIA	EI627905 Corp	6.25	11/04/2014
11	MERCEDES-BENZ AUSTRALIA	EI894424 Corp	5.25	12/12/2014
12	ETSA UTILITIES FINANCE	EI619051 Corp	6.75	29/09/2016
13	AUSTRALIA PACIFIC AIRPOR	EI363004 Corp	6.50	25/08/2014
14	AUSTRALIA PACIFIC AIRPOR	EF188672 Corp	6.00	14/12/2015
15	AUSTRALIA PACIFIC AIRPOR	EI363012 Corp	7.00	25/08/2016
16	NATIONAL AUSTRALIA BANK	EG566188 Corp	7.25	21/12/2017
17	STOCKLAND TRUST MANAGEME	EI083701 Corp	8.50	18/02/2015
18	STOCKLAND TRUST MANAGEME	EI494819 Corp	7.50	1/07/2016
19	STOCKLAND TRUST MANAGEME	EI475100 Corp	8.25	25/11/2020
20	SPI ELECTRICITY & GAS	EI193940 Corp	7.50	25/09/2017
21	SPI AUSTRALIA ASSETS PTY	EI340883 Corp	7.00	12/08/2015
22	SPI AUSTRALIA ASSETS PTY	EJ021352 Corp	6.25	21/02/2017
23	TRANSURBAN FINANCE CO PT	EI188381 Corp	7.25	24/03/2014
24	TRANSURBAN FINANCE CMPNY	EF069537 Corp	4.69	10/11/2015
25	VOLKSWAGEN FIN SERV AUST	EI201050 Corp	7.75	31/03/2014
26	VOLKSWAGEN FIN SERV AUST	EI880238 Corp	5.25	21/11/2014
27	VOLKSWAGEN FIN SERV AUST	EI546029 Corp	7.00	28/01/2015

Source: Bloomberg.

1508. The Authority considered two scenarios in estimating the debt risk premium using the bond-yield approach:

- Scenario I - a full sample of 27 Australian corporate bonds; and
- Scenario II - a smaller sample excluding all bonds with a term to maturity of less than 5 years.

1509. For each of the two scenarios above, the following four weighted average methods were considered:

- a simple average;
- a term-to-maturity weighted average approach;
- an amount-issued weighted average approach; and

- a median approach.

1510. The Authority considered in the Draft Decision that the estimated 5-year nominal risk-free rate of return should be 3.67 per cent, for the period until 29 February 2012. This nominal risk free rate was estimated for a 5 year CGS. The same principle was applied to estimate the risk free rate for Australian corporate bonds with more (or less) than 5 year term to maturity. The risk free rate for 5 year CGS must be adjusted to reflect the fact that bonds in the benchmark sample have longer (or shorter) than a 5 year term to maturity.

Table 163 Observed Yields, Adjusted Nominal Risk Free Rate, the Debt Risk Premium for A- Australian Corporate Bond as at 29 February 2012.

Number	Issuer	Term to maturity as at 31 January 2012	Observed yields (%)	Risk Free rate (%)	Debt Risk Premium (%)
1	AUST & NZ BANKING GROUP	5.01	5.707%	3.672%	2.035%
2	AUST & NZ BANKING GROUP	5.63	5.752%	3.761%	1.991%
3	AUST & NZ BANKING GROUP	10.31	5.793%	4.117%	1.676%
4	COMMONWEALTH BANK AUST	5.24	5.581%	3.715%	1.867%
5	POWERCOR AUSTRALIA LLC	9.88	5.739%	4.079%	1.660%
6	COCA-COLA AMATIL LTD	2.25	4.451%	3.590%	0.862%
7	COCA-COLA AMATIL LTD	4.92	5.185%	3.667%	1.518%
8	COCA-COLA AMATIL LTD	9.58	5.422%	4.052%	1.369%
9	COMMONWEALTH PROP FUND	4.78	4.706%	3.664%	1.042%
10	MERCEDES-BENZ AUSTRALIA	2.11	5.149%	3.590%	1.559%
11	MERCEDES-BENZ AUSTRALIA	2.78	5.005%	3.583%	1.422%
12	ETSA UTILITIES FINANCE	4.58	5.812%	3.659%	2.152%
13	AUSTRALIA PACIFIC AIRPOR	2.49	5.965%	3.587%	2.378%
14	AUSTRALIA PACIFIC AIRPOR	3.79	6.407%	3.645%	2.762%
15	AUSTRALIA PACIFIC AIRPOR	4.49	6.207%	3.657%	2.550%
16	NATIONAL AUSTRALIA BANK	5.81	5.939%	3.768%	2.170%
17	STOCKLAND TRUST MANAGEME	2.97	6.164%	3.583%	2.581%
18	STOCKLAND TRUST MANAGEME	4.34	6.534%	3.654%	2.880%
19	STOCKLAND TRUST MANAGEME	8.74	7.173%	3.987%	3.186%
20	SPI ELECTRICITY & GAS	5.57	6.136%	3.758%	2.378%
21	SPI AUSTRALIA ASSETS PTY	3.45	5.731%	3.616%	2.114%
22	SPI AUSTRALIA ASSETS PTY	4.98	6.212%	3.669%	2.543%
23	TRANSURBAN FINANCE CO PT	2.07	5.916%	3.590%	2.327%
24	TRANSURBAN FINANCE CMPNY	3.69	5.376%	3.644%	1.732%
25	VOLKSWAGEN FIN SERV AUST	2.09	5.443%	3.590%	1.853%
26	VOLKSWAGEN FIN SERV AUST	2.73	5.472%	3.583%	1.889%
27	VOLKSWAGEN FIN SERV AUST	2.91	5.740%	3.583%	2.157%

1511. For example, row 5 of Table 163 shows that the nominal risk free rate for the Powercor bond with 9.88 years to maturity is 4.079 per cent for the 20 trading day period to 29 February 2012.[409] By comparison, the nominal risk free rate for this company, which has been used to estimate the debt risk premium for this bond in the benchmark sample, is higher than the risk-free rate for a 5-year CGS. This is

409 For example, Commonwealth Prop Fund bond will mature on 11 December 2016. As such, the straddle dates which are used to estimate the risk free rate for the Commonwealth Prop Fund bond are 15 February 2017 (for the CGS bond TB120) and 21 July 2017 (for the CGS bond TB135). The two straddle values on these two straddle dates will be interpolated in the same principle with the interpolation process for the nominal risk free rate to estimate the interpolated nominal CGS yield for the Commonwealth Prop Fund bond on the maturity date.

consistent with the finance principle of risk and return trade-off: for longer investments with higher risks, higher returns are required.

1512. The debt risk premiums calculated under the different scenarios and different weighted average methods are summarised in Table 164 below.

Table 164 Debt Risk Premiums under Various Scenarios and Weighted Average Approach, (per cent) as at 29 February 2012

Weighted Average Method	Scenario 1 27 bonds	Scenario 2 8 bonds	Simple Average of all 2 scenarios
Simple Average	2.003%	2.022%	2.012%
Term to Maturity Weighted Average	**2.003%**	**2.052%**	**2.027%**
Amount Issued Weighted Average	1.961%	2.037%	1.999%
Median	2.013%	2.128%	2.070%

Source: Economic Regulation Authority's Analysis

1513. Consistent with previous decisions, the Authority considered that the term-to-maturity weighted average method is likely to reflect the current conditions in the market for funds. As such, the debt risk premium was calculated as a simple average of the two term-to-maturity weighted average scenarios.

1514. As a result, for the 20-day trading period until 29 February 2012 for the Draft Decision for Western Power's Revised Access Arrangement, the Authority was of the view that a debt risk premium of 2.027 per cent was reasonable.

Western Power's Response to the Draft Decision

1515. Western Power submitted that it has concerns regarding both aspects of the Authority's methodology using the bond-yield approach and the 5-year term to maturity of the risk free rate. Western Power argued that the Authority's current approach to estimating the cost of debt does not meet the requirements of the Access Code.[410]

1516. On the advice of CEG, Western Power has revised its debt risk premium range of 3.67 to 4.03 per cent, which is based on possible extrapolations of the Bloomberg BBB fair value curve, being:

- the average annualised Australian Bloomberg BBB 7 year fair value between 5 March 2012 and 30 March 2012 of 7.63 per cent; *less*
- the average annualised 7-year CGS yield between 5 March 2012 and 30 March 2012 of 3.97 per cent; *plus*

[410] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 162.

- a range of 0.00% to 0.36%, being between 0 and 12 basis points per annum for three years.

1517. Western Power submits that it has selected a conservative estimate of the debt risk premium by revising its estimate of the debt risk premium of 3.67 per cent in the revised proposed revisions to the access arrangement.[411]

1518. Western Power, together with its consultant CEG, raised many different issues in relation to the Authority's estimates of the debt risk premium using the bond-yield approach. These issues can be summarised as follows:

- a benchmark term of the cost of debt;
- Bloomberg's Fair Value Curves;
- extrapolation of Bloomberg's Fair Value Curves; and
- adjusting the debt risk premium and fitting the fair value curves.

1519. Each of these issues is presented in turn below.

A benchmark term for the cost of debt

1520. CEG does not agree with the Authority's assessment that the fact that 52.5 per cent of total debt instruments, as presented in Table 160, having an average term of 5 years or less means that the term of the cost of debt is 5 years. CEG argues that the data put forward by the Authority measures the term of debt not from time of issue, but from the time of reporting. As such, CEG considers that the Authority has established that the average term to maturity remaining on debt for regulated energy network businesses may be approximately five years. CEG argued that the Authority's observation is entirely consistent with the average term to maturity of debt at issue by regulated network businesses being 10 years.[412]

1521. CEG also submitted the proposed logic for basing the benchmark term of debt issued on the term of the regulatory period ignores the efficient term of debt financing in its derivation. CEG argued that the logic for doing so is the assumption that, if a business refinanced all debt at the beginning of each regulatory period, the present value of compensation would only equal the present value of costs if it was based on issuing 5 year debt. CEG argued that this is correct; however, it is only true if this is what businesses actually do. CEG submitted that whether or not businesses do this will depend on whether it is efficient to do so. CEG was of the view that there is nothing in the above logic that establishes that it is efficient to issue 5 year debt.[413]

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[411] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 163.

[412] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 6-8.

[413] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 6-8.

Bloomberg's Fair Value Curves

1522. Based on the advice of CEG, Western Power submitted that the use of Bloomberg fair value curves is superior to the Authority's bond-yield approach.[414]

1523. CEG argued that relying on an independent expert opinion, such as that of Bloomberg, subject to appropriate reasonableness testing, is likely to give rise to a more accurate estimate of the DRP than reliance on specific bond yields as proposed by the ERA. CEG also submitted that a presumption should exist in favour of adopting Bloomberg's estimate, unless there is compelling evidence suggesting that the measurement of the DRP based on the Bloomberg curve would be unreasonable.[415]

1524. CEG submitted that it assessed the reasonableness of Bloomberg's process of extrapolating its fair value curves using observed bond yields (including bonds denominated in Australian dollars and foreign currency) during the relevant averaging period. CEG argued that the results of its analysis indicate that the extrapolation of Bloomberg's BBB fair value curve is reliable from an empirical perspective, as well as a principled one.[416]

1525. CEG conducted its analysis to test the fitness of Bloomberg's fair value curve with observed bond yields. CEG selected a sample of bonds to include fixed and floating corporate bonds issued in Australia in Australian dollars rated BBB to A-, with maturity greater than one year. CEG argued that this large dataset provides a cross-check on the reasonableness of the extrapolated Bloomberg BBB fair value curve.

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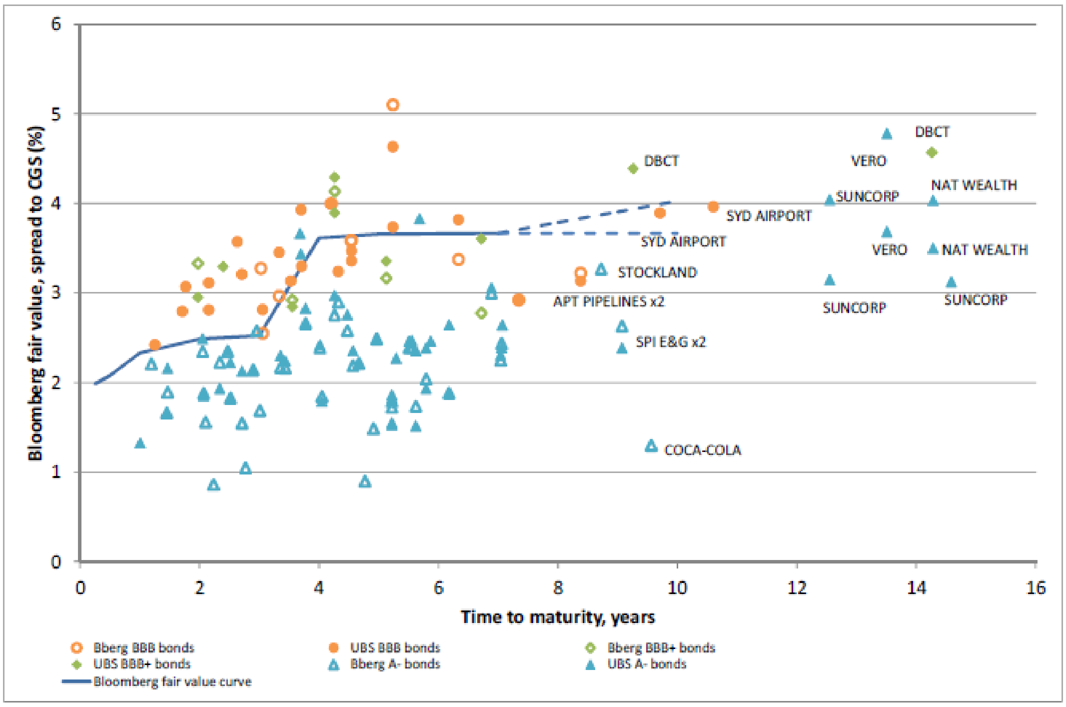
[414] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 162.

[415] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 1.

[416] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 1.

Figure 13 CEG's extrapolated BBB Fair Value Curve & Observed Yields: BBB to A- Australian Corporate Bonds with Maturity greater than One Year



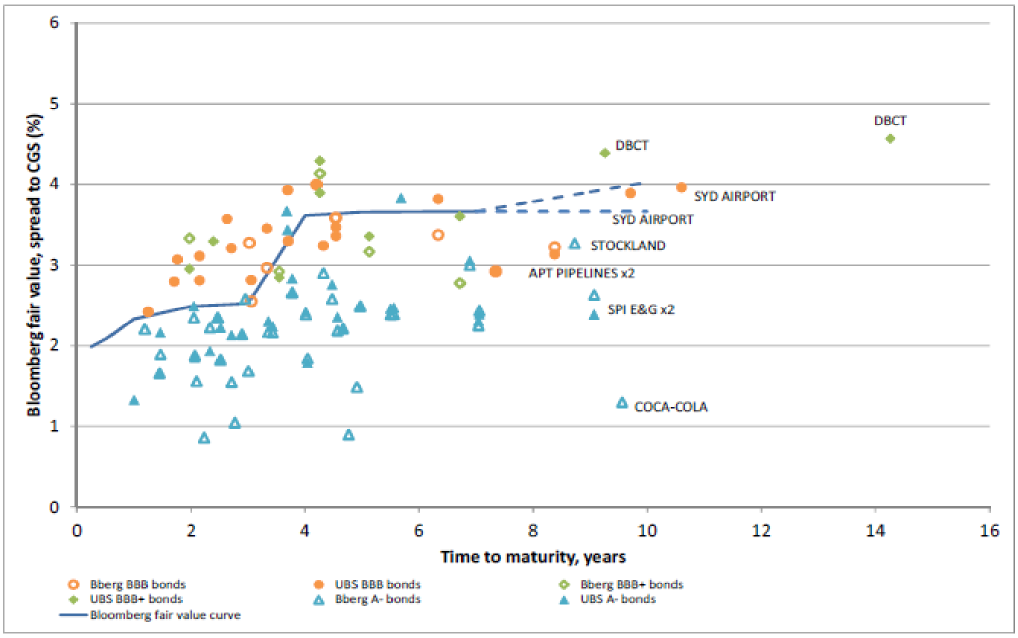
Source: Bloomberg, UBS, RBA and CEG analysis

Source: CEG, 2012, Figure 2, p. 18.

1526. CEG then decided to exclude bonds issued by Coca Cola Amatil and SPI Electricity and Gas. The reason for this exclusion is that the two bonds are not representative in comparison with other bonds in the sample.[417]

[417] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 21-2.

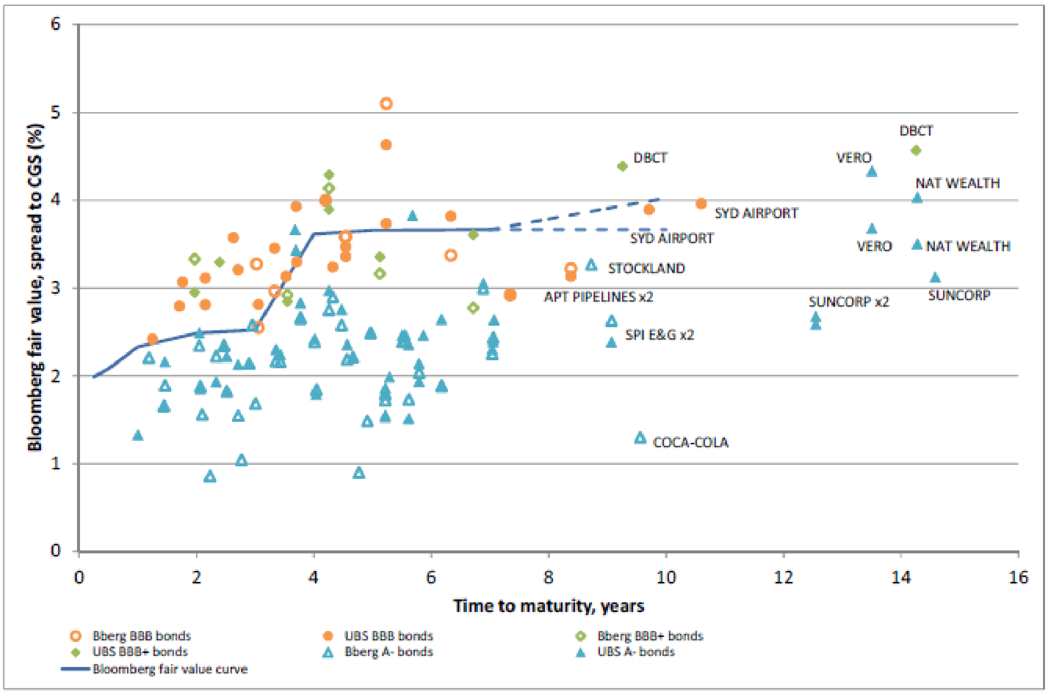
Figure 14 CEG's Bonds with Maturity greater than One Year rated BBB to A- (excluding Callable but not Make-whole Callable bonds)



Source: Bloomberg, UBS, RBA and CEG analysis
Note: Data sourced as an average over 5 March 2012 to 30 March 2012

Source: CEG, 2012, Figure 3, p. 22.

Figure 15 Bonds with maturity greater than one year rated BBB to A- (Oakvale adjustment applied to callable bonds)



Source: Bloomberg, UBS, RBA and CEG analysis. Maturity dates for callable bonds are final maturity date for the bond (i.e., not call date).
Note: Data sourced as an average over 5 March 2012 to 30 March 2012

Source: CEG, 2012, Figure 4, p. 24.

1527. CEG also submitted that callable bonds should not be excluded from the sample. However, their yields need to be adjusted to make "like with like" comparison with the other bonds in the sample. CEG also noted that the callable bonds are included in the benchmark sample of the Authority's bond-yield approach.[418] CEG also presented the comparison of Bloomberg's fair value curve with observed yields from the sample of bonds when all callable bonds are excluded and when all callable bonds are adjusted using Oakvale's approach in their advice to the AER in 2011.[419]

1528. CEG then conducted cross-checks on the Bloomberg fair value curve. CEG submitted that the cross-checks involve consideration of:[420]

- the yields on bonds issued by Australian firms in foreign currencies, swapped back into Australian dollar terms;
- curve-fitting techniques applied to the yields on bonds issued by Australian firms in Australian dollars; and
- foreign fair value curves, swapped back into Australian dollar terms.

1529. Based on its analyses, CEG was of the view that the above cross-checks establish conclusively the reasonableness of the extrapolated Bloomberg BBB fair value curve over the 5 March 2012 to 30 March 2012 period, and that it is a good fit to the available data.[421]

Extrapolation of the Bloomberg fair value curve

1530. CEG submitted that using historical estimates from the Bloomberg AAA fair value curve as a method for extrapolation from 7-year to 10-year fair value curve was proposed by CEG in 2010. CEG was of the view that it did not envisage that it would remain appropriate to apply without review for an extended period into the future.[422]

1531. CEG also submitted that it had conducted such a review for data sourced from May 2011 for APT Petroleum Pipelines. From that analysis, CEG concluded that the above extrapolation method was still superior to a number of alternatives and generally consistent with contemporaneous market evidence.[423] Alternative methods include (i) extrapolation based on the CGS curve; (ii) linear extrapolation between 7 and 10 years; or (iii) extrapolation based on trends identified between pairs of bonds with the same issuer dated at approximately 7 and 10 years.

1532. As a result, CEG submitted that it is appropriate to continue using the Bloomberg AAA fair value curve information from 2010 to extrapolate the debt risk premium

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[418] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 22-3.

[419] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 23-4.

[420] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 26.

[421] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 26.

[422] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 49.

[423] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 50.

calculated on the Bloomberg BBB fair value curve from 7 to 10 years during May 2011.[424]

1533. CEG then considered information available on the extrapolation, as presented below:

- bond pair analysis (ranging from – 3 to 12 bps increase per year);
- foreign fair value curve analysis (ranging from – 3 to 12 bps increase per year);
- CEG curve fitting analysis (ranging from – 3 to 12 bps increase per year); and
- Bloomberg historical fair value values (ranging from – 3 to 12 bps increase per year).

CEG concluded that a reasonable extrapolation methodology for extending the Bloomberg BBB fair value curve from 7 to 10 years, using CGS yields, over the period considered from 5 March 2012 to 30 March 2012 would result in an increase in DRP of between 0 and 12 basis points per year, for a total of between 0 and 36 basis points.[425]

CEG's responses to the Authority's bond-yield approach

1534. CEG argued that the reasons set out by the Authority for rejecting the use of the Bloomberg fair value curve are not robust. CEG was of the view that the "bond-yield" approach developed by the Authority is not sufficiently developed or sophisticated that it could be capable of replacing the type of expertise provided in Bloomberg's fair value estimates. CEG noted that the AER's position in its Powerlink and Aurora decisions has now been superseded by the final Powerlink decision in which the AER reverts to the use of extrapolated Bloomberg BBB fair values.[426]

1535. At a detailed level, CEG submitted that they could not locate 3 bonds. CEG also questioned the rationale for not including another 13 bonds in the Authority's benchmark sample to determine the debt risk premium in Western Power's Draft Decision.[427]

1536. CEG also submitted that UBS data should be used. CEG expressed its concerns about inclusion of only BBB-band bonds in the Authority's benchmark sample. CEG agreed that while it is true that bonds with other credit ratings may not be expected to have a debt risk premium consistent with the benchmark credit rating, this does not mean that they may not be useful in informing an assessment of the debt risk premium.[428]

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[424] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 50.

[425] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 54, Table 7.

[426] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 56.

[427] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, pp. 60-1.

[428] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 63.

1537. CEG was of the view that none of the four weighted average methods as set out in the Authority's bond-yield approach is capable of taking into account the shape of the yield curve (and debt risk premium curve). CEG argued that the yield curve should be developed using the debt risk premium from the bond yield approach.[429] CEG proposed and submitted two different methods, which are discussed in turn below.

Using the Bloomberg's A Fair Value Curve to adjust bond DRP for maturity

1538. CEG was of the view that a more reliable estimate is to adjust downward or upward to the preferred benchmark maturity (either 5 years or 10 years) by adding the difference between the Bloomberg fair value at that benchmark and the Bloomberg fair value at the maturity of the bond. CEG submitted that the effect of doing so is simply to increase or decrease the yield of the bond along a line parallel to the Bloomberg's fair value curve. CEG's analysis for the period of 20 trading days to 29 February 2012 indicates that the debt risk premium for a 5 year term and a 10 year term under various scenarios range from 2.26 per cent to 3.07 per cent; and from 2.54 per cent to 3.40 per cent, respectively.[430]

Curve Fitting the Benchmark Yield

1539. CEG submitted that the level of the curve for A- bonds is derived solely by reference to the yields on A- bonds. For the 20 trading days to 30 March 2012, the 5 year and 10 year debt risk premium estimates on maturity adjusted samples using curve fitting range from 2.50 per cent to 2.87 per cent; and from 2.63 per cent to 3.36 per cent, respectively.[431]

Public Submissions to Draft Decision

1540. The Authority did not receive any public submissions on this issue.

Final Decision

Responses to Western Power's comments

1541. The Authority considers that there are two key issues in relation to Western Power's proposed estimate of the debt risk premium.

- First, the adoption of 5 years as the term to maturity for an estimate of a risk free rate. As previously discussed from paragraph 1381 to paragraph 1403, the Authority is of the view that a 5 year term to maturity is appropriate for the purpose of estimating the risk free rate of return.
- Second, the use of Bloomberg's fair value curves with relevant extrapolations to derive the debt risk premium. It is noted that the Authority has not raised any concern with Bloomberg's fair value curves specifically. The Authority's only concern is that these fair value curves may not be developed for the

[429] Competition Economists Group, 2012, *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 64.

[430] Competition Economists Group, 2012. *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 67, Table 8.

[431] Competition Economists Group, 2012. *Western Power's proposed debt risk premium,* Prepared for Western Power, p. 68, Table 9.

purpose of estimating the debt risk premium for regulated businesses, particularly in an environment when the bond market is not liquid.

1542. The Authority considers that the rationale for a departure from Bloomberg's fair value curves and extrapolations to estimating the debt risk premium was discussed in length in its Discussion Paper on "*Measuring the debt risk premium: A bond-yield approach*", released on 1 December 2010 and in the Final Decision on Western Australia Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems, released on 28 February 2011. In the Discussion Paper, the Authority considered that Bloomberg's estimate of 7-year BBB fair value curve for Australian corporate bonds is problematic. In addition, the Authority is also of the view that extrapolation from 7-year into 10-year fair value curve is also problematic. The Authority remains of the view set out in those documents and does not propose to repeat the discussion in detail again in this Final Decision.[432]

A benchmark term for the cost of debt

1543. The Authority is of the view that the current debt profiles of Australian firms rated by S&P is key evidence in determining the benchmark term to maturity for regulated businesses used in estimating the debt risk premium. This was previously discussed in paragraphs 1389 to 1392. The resultant term is five years, which is consistent with findings from S&P's own observations and academic studies, including those of Professors Davis and Lally. In addition, the Authority has consistently observed over the last three years that the average term of debt for Australian companies in the benchmark sample is generally five years.

1544. The Authority considers that if Australian businesses increasingly favour using terms for their debts that are longer than 5 years, then the average of this term from the benchmark sample would be more than 5 years and the calculation of the debt risk premium using the bond yield approach would account for this longer average term.

1545. In conclusion, the Authority is of the view that it is appropriate to adopt the term of 5 years in the determination of the debt risk premium in this Final Decision. Adopting a 5 year term is also consistent with the term of the risk free rate of return.

Bloomberg's Fair Value Curves

1546. The Authority is not in a position to question Bloomberg's expertise in relation to its derivation of the fair value curves for Australian corporate bonds denominated in Australian dollars. However, the Authority is not convinced that Bloomberg's estimate of the fair value curves for a longer term to maturity such as the 7-year BBB fair value curve for Australian corporate bonds is appropriate for regulatory purposes. The Authority notes that Bloomberg's estimate of the 7-year BBB fair value curve lies above the observed yields from the bonds included in Bloomberg's sample of bonds from which the fair value curve is estimated. Bloomberg's method for estimating the fair value curves is proprietary information. As such, the Authority is unable to verify the estimates. The Authority notes that Bloomberg has used the

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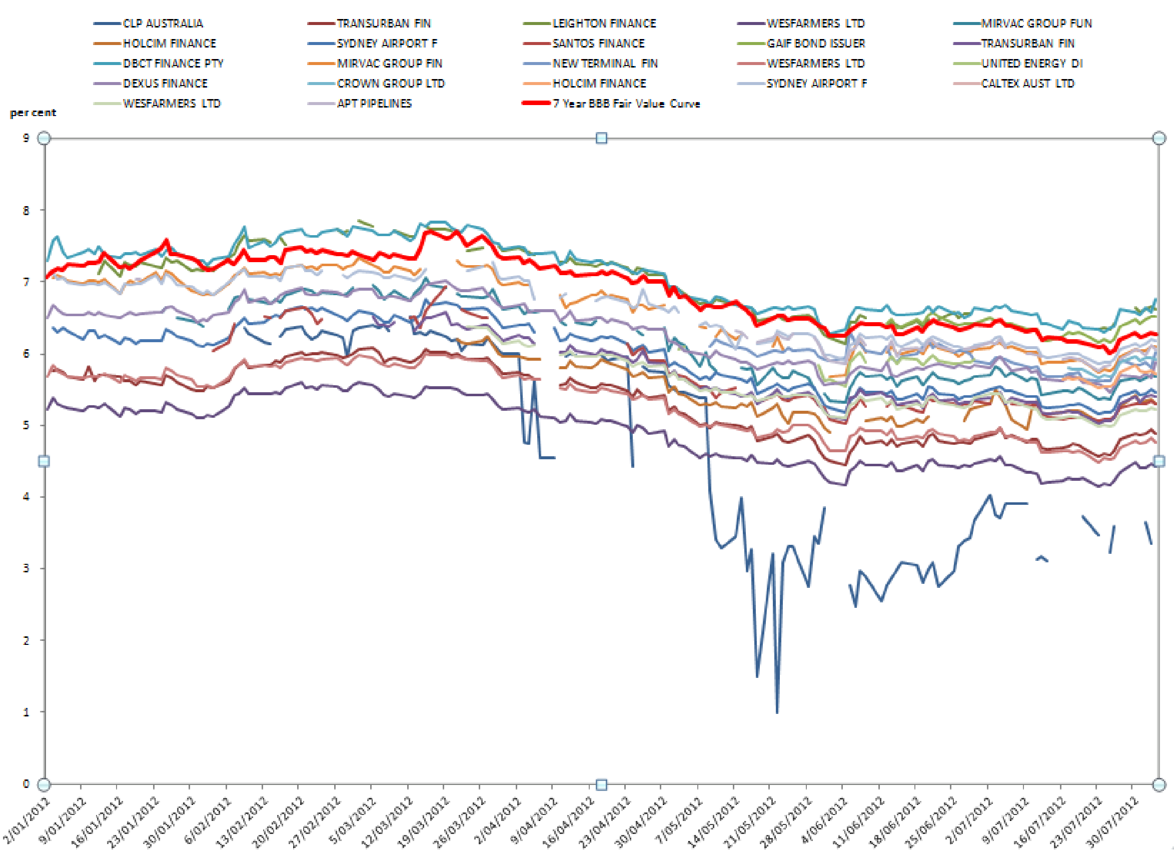
[432] This decision is available at http://www.erawa.com.au/3/1076/48/wa_gas_networks_formerly_alintagas_distribution_sy.pm, Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 70-92.

same sample of the underlying bonds in which fair value curves with different terms to maturity are derived. The Authority observes that while the fair value curve for shorter terms to maturity fits relatively well with the observed yields of the bonds in the sample, the 7-year BBB fair value curve does not. Also, Bloomberg's methodology of estimating fair value curves is not publicly available. As such, the Authority is unable to verify the above estimates.

1547. Figure 16 below again indicates that the 7-year BBB fair value curve for Australian corporate bonds significantly deviates from the observed yields and the estimate of this fair value curve generally lies above the observed yields. This finding is consistent with the Authority's observation in late 2010 and it was the main impetus for the Authority's decision to develop the bond-yield approach. It is interesting to note that this was not the case prior to 2010, when Australian bond markets were relatively liquid. The retrospective test in the Authority's Discussion Paper on "*Measuring a Debt Risk Premium: A Bond-yield Approach*" (released in December 2010) confirmed this outcome.

Figure 16 Bloomberg's 7-year BBB Fair Value Curve versus Underlying Australian BBB Bonds, January 2012 to August 2012



Source: Bloomberg and Economic Regulation Authority's analysis

Extrapolation of the Bloomberg fair value curve

1548. In its analysis, CEG concluded that the most appropriate method to derive the 10 year debt risk premium is to extrapolate from the 7-year BBB fair value curve, using the spread between 10-year and 7-year AAA fair value curves. The Authority acknowledges that this method was adopted by the AER in the past.

1549. It is noted that Bloomberg ceased producing the 10-year and 7-year AAA fair value curves in June 2010. It is now more than 24 months since these fair values curves were produced and these estimates are still proposed by Western Power to be adopted. It is understood that the main reason that Bloomberg ceased producing its estimates of these two long term fair value curves for AAA Australian corporate bonds was due to a concern about data quality and the illiquid Australian bond market. The Authority is not convinced that using parameters derived from 2 year old data could be construed as assisting in the determination of a rate of return that reflects the prevailing conditions in the market for funds in August 2012.

1550. The Authority reiterates that it is not convinced of the validity of determining a debt risk premium using Bloomberg's estimate of the 7-year BBB fair value curve for Australian corporate bonds and an extrapolation approach from a 7-year term into a 10-year term. As such, the Authority concludes that the bond-yield approach that considers the daily observed yields from Australian corporate bonds is the most appropriate method to be used in estimating the debt risk premium for this Final Decision.

CEG's responses to the Authority's bond-yield approach

1551. The Authority does not agree with CEG's proposal that the debt risk premium for each bond in the benchmark sample should be adjusted using Bloomberg's estimated fair value curve. The Authority is of the view that Bloomberg's estimates of fair value curves involve various adjustments that are not publicly available for verification. As such, an adjustment to the debt risk premium based on the observed yields for each bond in the benchmark sample is ad hoc and unsustainable. The centrepiece of the Authority's bond-yield approach is the observed yields for Australian corporate bonds included in the benchmark sample. These observed yields from the corporate bonds will reflect the prevailing conditions in the market for funds. The Authority concludes that any ad hoc adjustment is inappropriate and therefore should not be used. The Authority also considers that CEG has not taken into account the prevailing conditions in the market for funds when extrapolating using Bloomberg's estimates of the fair value curves in its proposal.

1552. In addition, in its most recently released decisions on the *Application by WA Gas Networks Pty Ltd* and on the *Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14* the ACT concluded that the Authority's bond-yield approach was a valid approach to estimate the debt risk premium for regulated businesses.[433]

Conclusion

1553. In conclusion, the Authority is of the view that it is appropriate to use the bond-yield approach and the 5 year term of the risk free rate to estimate the cost of debt for this Final Decision.

1554. As a consequence, the Authority considers that it is appropriate to include Australian corporate bonds with the credit ratings of A-, BBB+ and BBB in the benchmark sample of the bond-yield approach for estimating the debt risk premium for this Final Decision, as discussed in paragraphs 1478 to 1483.

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[433] Australian Competition Tribunal, 2012, *Application by WA Gas Networks Pty Ltd (No 3) [2012] ACompT 12*, 8th June 2012, paragraph 179, p. 43.

Estimates of the Debt Risk Premium

1555. Table 165 below presents the benchmark sample of A-, BBB+ and BBB rated bonds that make up the sample used in the bond-yield approach. This sample was available over the 20 trading day averaging period up until 15 June 2012 - the period that Western Power proposed.

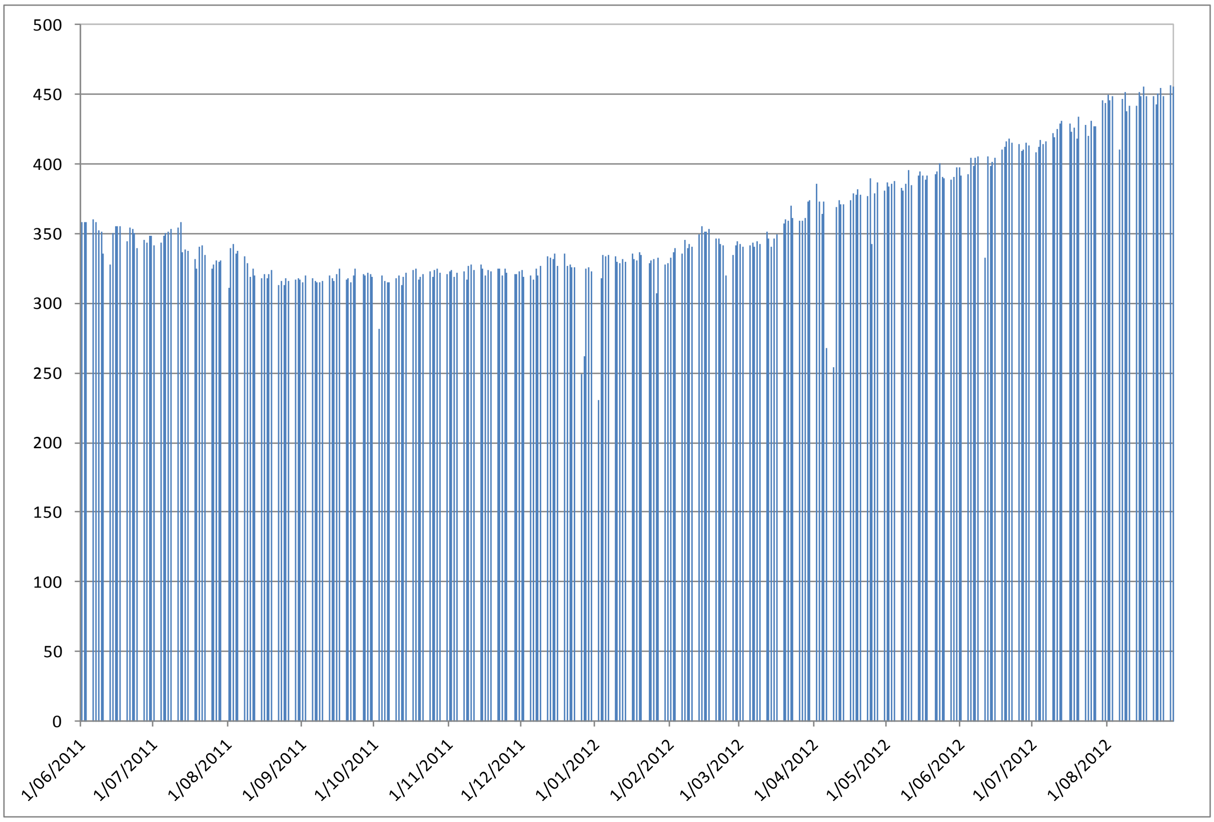
Table 165 A Benchmark Sample of Australian Corporate Bonds S&P Credit Rating of A-, BBB + and BBB as at 15 June 2012

Number	Issuer	Ticker	Coupon (Per cent)	Redemption
1	AUST & NZ BANKING GROUP	EG919776 Corp	7.75	18/10/2017
2	POWERCOR AUSTRALIA LLC	EJ138911 Corp	5.75	27/04/2017
3	COCA-COLA AMATIL LTD	EI963715 Corp	4.88	1/02/2017
4	COCA-COLA AMATIL LTD	EI814473 Corp	5.95	27/09/2021
5	COMMONWEALTH PROP FUND	EI598880 Corp	7.25	11/03/2016
6	COMMONWEALTH PROP FUND	EI060572 Corp	5.25	11/12/2016
7	MERCEDES-BENZ AUSTRALIA	EI894424 Corp	5.25	12/12/2014
8	MERCEDES-BENZ AUSTRALIA	EJ049426 Corp	5.50	9/03/2015
9	MERCEDES-BENZ AUSTRALIA	EJ177530 Corp	4.50	18/05/2015
10	ETSA UTILITIES FINANCE	EI619051 Corp	6.75	29/09/2016
11	ETSA UTILITIES FINANCE	EJ048937 Corp	6.25	7/09/2017
12	GPT RE LTD	EI963443 Corp	6.75	24/01/2019
13	AUSTRALIA PACIFIC AIRPOR	EI363004 Corp	6.50	25/08/2014
14	AUSTRALIA PACIFIC AIRPOR	EF188672 Corp	6.00	14/12/2015
15	AUSTRALIA PACIFIC AIRPOR	EI363012 Corp	7.00	25/08/2016
16	NATIONAL AUSTRALIA BANK	EG566188 Corp	7.25	21/12/2017
17	QIC SHOPPING CENTRE FUND	EI647047 Corp	6.75	7/07/2014
18	STOCKLAND TRUST MANAGEME	EI083701 Corp	8.50	18/02/2015
19	STOCKLAND TRUST MANAGEME	EI494819 Corp	7.50	1/07/2016
20	STOCKLAND TRUST MANAGEME	EI475100 Corp	8.25	25/11/2020
21	SPI ELECTRICITY & GAS	EI193940 Corp	7.50	25/09/2017
22	SPI ELECTRICITY & GAS	EI626314 Corp	7.50	1/04/2021
23	SPI AUSTRALIA ASSETS PTY	EI340883 Corp	7.00	12/08/2015
24	SPI AUSTRALIA ASSETS PTY	EJ021352 Corp	6.25	21/02/2017
25	DBCT FINANCE PTY LTD	EF461870 Corp	6.25	9/06/2016
26	CALTEX AUSTRALIA LTD	EI883417 Corp	7.25	23/11/2018
27	SANTOS FINANCE LIMITED	EF102609 Corp	6.25	23/09/2015
28	NEW TERMINAL FINANCING C	EF641357 Corp	6.25	20/09/2016
29	APT PIPELINES LTD	EI325336 Corp	7.75	22/07/2020
30	BRISBANE AIRPORT CORP LT	EI620440 Corp	8.00	9/07/2019
31	UNITED ENERGY DISTRIBUTI	EJ118108 Corp	6.25	11/04/2017
32	HOLCIM FINANCE AUSTRALIA	EJ096330 Corp	7.00	27/03/2015
33	SYDNEY AIRPORT FINANCE	EI308853 Corp	8.00	6/07/2015
34	MIRVAC GROUP FUNDING LTD	EI195249 Corp	8.25	15/03/2015
35	MIRVAC GROUP FINANCE LTD	EI414696 Corp	8.00	16/09/2016
36	SYDNEY AIRPORT FINANCE	EI684902 Corp	7.75	6/07/2018

Source: Bloomberg.

1556. As presented in paragraph 1403, the Authority considers that the estimated 5 year nominal risk-free rate of return should be 2.52 per cent for the period until 15 June 2012. This nominal risk free rate is estimated for a 5 year CGS. The same principle is applied to estimate the risk free rate for Australian corporate bonds with terms to maturity more (or less) than 5 years. The risk free rate for a 5 year CGS must be adjusted to reflect the fact that bonds in the benchmark sample have terms to maturity longer (or shorter) than 5 years.

Figure 17 Number of Australian Investment Grade Bonds with Non-Zero Bids, June 2011 – August 2012



Source: Bloomberg and the Economic Regulation Authority's analysis

1557. Figure 17 indicates that the Australian bond market in June 2012 was relatively liquid compared with other periods. This is the averaging period proposed by Western Power and agreed by the Authority to be adopted in estimating the market-based WACC parameters for this Final Decision. The Authority observed that there have been more debt securities in July and August 2012 compared to June 2012 as presented in Figure 17 above.

Table 166 Observed Yields, Adjusted Nominal Risk Free Rates and Debt Risk Premium for A-, BBB+, and BBB Australian Corporate Bonds for the Period to 15 June 2012 (per cent)

Number	Issuer	Term to Maturity as at 15 June 2012 (Years)	Observed yields (%)	Risk Free rate (%)	Debt Risk Premium (%)
1	AUST & NZ BANKING GROUP	5.34	4.150	2.586	1.563
2	POWERCOR AUSTRALIA LLC	4.87	5.115	2.487	2.628
3	COCA-COLA AMATIL LTD	4.63	4.079	2.440	1.639
4	COCA-COLA AMATIL LTD	9.28	4.516	2.990	1.526
5	COMMONWEALTH PROP FUND	3.74	5.000	2.378	2.623
6	COMMONWEALTH PROP FUND	4.49	4.432	2.428	2.004
7	MERCEDES-BENZ AUSTRALIA	2.49	3.847	2.351	1.495
8	MERCEDES-BENZ AUSTRALIA	2.73	4.116	2.324	1.792
9	MERCEDES-BENZ AUSTRALIA	2.93	4.171	2.315	1.856
10	ETSA UTILITIES FINANCE	4.29	4.793	2.410	2.383
11	ETSA UTILITIES FINANCE	5.23	5.120	2.568	2.553
12	GPT RE LTD	6.61	5.849	2.719	3.130
13	AUSTRALIA PACIFIC AIRPOR	2.19	4.740	2.381	2.359
14	AUSTRALIA PACIFIC AIRPOR	3.50	5.043	2.369	2.674
15	AUSTRALIA PACIFIC AIRPOR	4.19	5.179	2.401	2.778
16	NATIONAL AUSTRALIA BANK	5.52	4.523	2.617	1.906
17	QIC SHOPPING CENTRE FUND	2.06	4.668	2.393	2.275
18	STOCKLAND TRUST MANAGEME	2.68	5.139	2.329	2.809
19	STOCKLAND TRUST MANAGEME	4.04	5.556	2.388	3.167
20	STOCKLAND TRUST MANAGEME	8.44	6.133	2.911	3.222
21	SPI ELECTRICITY & GAS	5.28	5.146	2.576	2.570
22	SPI ELECTRICITY & GAS	8.79	5.681	2.945	2.735
23	SPI AUSTRALIA ASSETS PTY	3.16	4.827	2.340	2.487
24	SPI AUSTRALIA ASSETS PTY	4.68	5.058	2.445	2.614
25	DBCT FINANCE PTY LTD	3.98	6.562	2.386	4.176
26	CALTEX AUSTRALIA LTD	6.44	6.108	2.705	3.404
27	SANTOS FINANCE LIMITED	3.27	5.301	2.352	2.948
28	NEW TERMINAL FINANCING C	4.26	6.029	2.408	3.622
29	APT PIPELINES LTD	8.10	6.113	2.878	3.235
30	BRISBANE AIRPORT CORP LT	7.07	5.799	2.766	3.033
31	UNITED ENERGY DISTRIBUTI	4.82	5.861	2.475	3.386
32	HOLCIM FINANCE AUSTRALIA	2.78	5.097	2.318	2.780
33	SYDNEY AIRPORT FINANCE	3.06	5.442	2.329	3.112
34	MIRVAC GROUP FUNDING LTD	2.75	5.618	2.321	3.297
35	MIRVAC GROUP FINANCE LTD	4.25	6.029	2.407	3.622
36	SYDNEY AIRPORT FINANCE	6.06	6.181	2.673	3.508

Source: Economic Regulation Authority's Analysis

1558. Table 166 shows that the nominal risk free rate for the United Energy Distribution bond with 4.82 years to maturity is 2.475 per cent for the 20 trading day period to

15 June 2012.[434] By comparison, the nominal risk free rate for the United Energy Distribution bond, which will be used to estimate the debt risk premium for this bond in the benchmark sample, is lower than the risk-free rate for a 5 year CGS. This is consistent with the finance principle of risk and return trade-off: for longer investments with higher risks, higher returns are required.

1559. Following the Draft Decision, the Authority has reconsidered the proper application of the bond yield approach in deciding on the appropriate debt risk premium pursuant to orders 1(e) and 2(b) of the Tribunal's Reasons in ATCO's and DBP's applications. In doing so, the Authority has had regard to the Tribunal's criticisms of the simple averaging process adopted in those final decisions.

1560. In its reasons in ATCO's application, the Tribunal found no error in the Authority's decision to depart from the Bloomberg fair value curve as a basis for estimating the debt risk premium. The Tribunal accepted that the bond yield approach was a valid basis for estimating the debt risk premium.

1561. However, the Tribunal did not agree with the Authority's decision to adopt a simple average across all of the scenarios in Table 20 of the Final Decision of the WAGN's access arrangement. The Tribunal was of the view that adopting this approach would lead to double and quadruple counting of certain of the sample bonds, which was undesirable, and with no reason being given as to why some bonds should be given more weight than others. The Tribunal therefore determined error and directed the Authority to re-make its decision by, amongst the other matters addressed in this decision, reconsidering the adoption of the simple averaging approach.

1562. The Tribunal accepted the Authority's "term to maturity" weighted average approach to determining the debt risk premium. As such, the Authority has maintained this approach in this Final Decision.

1563. Given that both the term to maturity and amount issued might be regarded as important in the market, the Authority has come to the view that there is merit in assigning weights to bonds with large issuance in comparison with other bonds in the benchmark sample. However, the Authority is of the view that further work needs to be undertaken to better reflect both characteristics in a joint weighting system for determining the debt risk premium, as recommended by the Tribunal. In the absence of further evidence and consistent with the Tribunal's observations, the Authority considers it is appropriate to apply a higher weight to bonds with larger issuance and longer terms to maturity for the purpose of this decision.

1564. The Authority considers that it is appropriate to use the *multiplicative rule* to account for the compounding effect.

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[434] For example, United Energy Distribution bond will mature on 11 April 2017. As such, the straddle dates which are used to estimate the risk free rate for the United Energy Distribution bond are 15 February 2017 (for the CGS bond TB120) and 21 July 2017 (for the CGS bond TB135). The two straddle values on these two straddle dates will be interpolated in the same principle with the interpolation process for the nominal risk free rate to estimate the interpolated nominal CGS yield for the United Energy Distribution bond on the mature date.

Table 167 The estimate of a Debt Risk Premium using a joint weighting mechanism

No.	Issuer	Amount ($ dollar)	Weight (Issuance)	Maturity	Term to Maturity as at 15 June 2012 (Years)	Weight (Term)	Combined Weight	Bond's Own DRP (%)	Contributed DRP (%)
1	AUST & NZ BANKING GROUP	290	0.040	18/10/2017	5.34	0.032	0.046	1.563	0.071
2	POWERCOR AUSTRALIA LLC	200	0.027	27/04/2017	4.87	0.029	0.029	2.628	0.075
3	COCA-COLA AMATIL LTD	250	0.034	1/02/2017	4.63	0.028	0.034	1.639	0.056
4	COCA-COLA AMATIL LTD	30	0.004	27/09/2021	9.28	0.055	0.008	1.526	0.013
5	COMMONWEALTH PROP FUND	200	0.027	11/03/2016	3.74	0.022	0.022	2.623	0.058
6	COMMONWEALTH PROP FUND	200	0.027	11/12/2016	4.49	0.027	0.026	2.004	0.053
7	MERCEDES-BENZ AUSTRALIA	100	0.014	12/12/2014	2.49	0.015	0.007	1.495	0.011
8	MERCEDES-BENZ AUSTRALIA	100	0.014	9/03/2015	2.73	0.016	0.008	1.792	0.014
9	MERCEDES-BENZ AUSTRALIA	175	0.024	18/05/2015	2.93	0.017	0.015	1.856	0.028
10	ETSA UTILITIES FINANCE	250	0.034	29/09/2016	4.29	0.026	0.032	2.383	0.075
11	ETSA UTILITIES FINANCE	200	0.027	7/09/2017	5.23	0.031	0.031	2.553	0.079
12	GPT RE LTD	150	0.021	24/01/2019	6.61	0.039	0.029	3.130	0.092
13	AUSTRALIA PACIFIC AIRPOR	100	0.014	25/08/2014	2.19	0.013	0.006	2.359	0.015
14	AUSTRALIA PACIFIC AIRPOR	100	0.014	14/12/2015	3.50	0.021	0.010	2.674	0.028
15	AUSTRALIA PACIFIC AIRPOR	250	0.034	25/08/2016	4.19	0.025	0.031	2.778	0.086
16	NATIONAL AUSTRALIA BANK	300	0.041	21/12/2017	5.52	0.033	0.049	1.906	0.093
17	QIC SHOPPING CENTRE FUND	200	0.027	7/07/2014	2.06	0.012	0.012	2.275	0.028
18	STOCKLAND TRUST MANAGEME	300	0.041	18/02/2015	2.68	0.016	0.024	2.809	0.067
19	STOCKLAND TRUST MANAGEME	150	0.021	1/07/2016	4.04	0.024	0.018	3.167	0.057
20	STOCKLAND TRUST MANAGEME	160	0.022	25/11/2020	8.44	0.050	0.040	3.222	0.128
21	SPI ELECTRICITY & GAS	300	0.041	25/09/2017	5.28	0.031	0.047	2.570	0.120
22	SPI ELECTRICITY & GAS	250	0.034	1/04/2021	8.79	0.052	0.065	2.735	0.177
23	SPI AUSTRALIA ASSETS PTY	500	0.068	12/08/2015	3.16	0.019	0.047	2.487	0.116
24	SPI AUSTRALIA ASSETS PTY	400	0.055	21/02/2017	4.68	0.028	0.055	2.614	0.144
25	DBCT FINANCE PTY LTD	150	0.021	9/06/2016	3.98	0.024	0.018	4.176	0.074
26	CALTEX AUSTRALIA LTD	150	0.021	23/11/2018	6.44	0.038	0.028	3.404	0.097
27	SANTOS FINANCE LIMITED	100	0.014	23/09/2015	3.27	0.019	0.010	2.948	0.028
28	NEW TERMINAL FINANCING C	100	0.014	20/09/2016	4.26	0.025	0.013	3.622	0.046
29	APT PIPELINES LTD	300	0.041	22/07/2020	8.10	0.048	0.072	3.235	0.232
30	BRISBANE AIRPORT CORP LT	200	0.027	9/07/2019	7.07	0.042	0.042	3.033	0.126
31	UNITED ENERGY DISTRIBUTI	200	0.027	11/04/2017	4.82	0.029	0.028	3.386	0.096
32	HOLCIM FINANCE AUSTRALIA	250	0.034	27/03/2015	2.78	0.017	0.021	2.780	0.057
33	SYDNEY AIRPORT FINANCE	175	0.024	6/07/2015	3.06	0.018	0.016	3.112	0.049
34	MIRVAC GROUP FUNDING LTD	200	0.027	15/03/2015	2.75	0.016	0.016	3.297	0.053
35	MIRVAC GROUP FINANCE LTD	225	0.031	16/09/2016	4.25	0.025	0.028	3.622	0.102
36	SYDNEY AIRPORT FINANCE	100	0.014	6/07/2018	6.06	0.036	0.018	3.508	0.063
	TOTAL	**7,305**	**1.000**		**168.02**	**1.000**	**1.000**		**2.708**

Source: The Economic Regulation Authority's analysis

1565. A combined weight that takes into account both characteristics of the bonds including their terms to maturity and the issuance amount, is calculated as follows.

- First, the product of term to maturity and the issuance, to be called "the contribution", is calculated for each bond in the sample.
- Second, the sum of all of these contributions is derived, to be called "the total".
- Third, the weight assigned to each bond is simply the ratio between its own contribution and the sample's total, to be called "the combined weight".
- Fourth, the combined weight for each bond is multiplied by its associated debt risk premium to derive the debt risk premium for each bond, to be called "the bond's debt risk premium".
- Fifth, the sum of the bonds' debt risk premiums is the estimate of the debt risk premium for the sample when the two characteristics of the term to maturity and issuance are considered.

1566. As a result, for the 20 trading day period until 15 June 2012 for the Final Decision on Western Power's Access Arrangement, the Authority is of the view that a debt risk premium of 2.708 per cent is reasonable.

Conclusion

1567. The Authority does not approve Western Power's revision to the methods used to estimate the debt risk premium and the term of the risk free rate. The Authority is of the view that the bond-yield approach should be used to estimate the debt risk premium for Western Power's Access Arrangement.

1568. For the 20-day trading period until 15 June 2012, the Authority is of the view that a debt risk premium of 2.708 per cent is reasonable.

Debt Issuance Costs

Western Power's initial proposal

1569. Western Power proposed that an allowance of 12.5 basis points per year for debt establishment costs be included in the debt risk premium.[435]

Draft Decision

1570. The Authority approves Western Power's proposal with regard to an inclusion of 12.5 basis points as the debt issuance costs in the calculation of the cost of debt.

1571. Debt raising costs may include underwriting fees, legal fees, company credit rating fees and any other costs incurred in raising debt finance. In practice, regulators across Australia have typically included an allowance of 12.5 basis points for these costs in the cost of debt, as an increment to the debt margin.

1572. The current allowance for debt raising costs of 12.5 basis points is based upon a benchmark analysis conducted by the Allen Consulting Group (**ACG**) in 2004.[436] The ACG undertook a study for the ACCC in 2004 on appropriate debt and equity raising costs to be included in costs recognised for the purposes of determining regulated revenues and prices. This study determined debt raising costs based on long-term bond issues, consistent with the assumptions applied in determining the costs of debt for a benchmark regulated entity. Debt raising costs were based on costs associated with Australian international bond issues and for Australian medium term notes sold jointly in Australia and overseas. Estimates of these costs were equivalent to 8 to 10.4 basis points per annum when expressed as an increment to the debt margin.[437] However, for regulatory certainty, Australian regulators have adopted a debt raising cost of 12.5 basis points.

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[435] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[436] Allen Consulting Group, December 2004, Debt and equity raising transaction costs: Final report to ACCC.

[437] Allen Consulting Group, December 2004, Debt and Equity raising transaction costs: Final report to ACCC.

1573. In determining the allowance for debt raising costs, the Authority also had regard to evidence more recently provided to the AER by Associate Professor Handley from the University of Melbourne in April 2010.[438] In this study, Handley considered that the available evidence of the debt raising cost is below the 12.5 basis points that has been adopted by Australian economic regulators. The Authority is also of the view that an allowance of 12.5 basis points provides regulatory certainty, given that this amount has been widely used in the past by Australian regulators.

Final Decision

1574. The Authority did not receive any public submissions in response to the Draft Decision in relation to the allowance of debt issuance cost.

1575. The Authority continues to be of the view that an allowance for debt raising costs of 12.5 basis points is appropriate to be included in the debt risk premium to calculate the total cost of debt for Western Power.

[438] Handley, J., April 2010, *A Note on the Completion Method*, Report prepared for the Australian Energy Regulator.

Market Risk Premium

Western Power's Initial Proposal

1576. Western Power submitted that a reasonable estimate of the MRP falls between 6.5 per cent and 8 per cent.[439] Western Power also stated that the proposed range is consistent with the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved and current capital market conditions.

Draft Decision

1577. In previous decisions, the Authority was of the view that it is appropriate to consider a wide range of evidence for the forward-looking, long-term estimates of the MRP, including:

- an estimate of the historical equity risk premium for the period for 1883 – 2010 by Associate Professor Handley in January 2011;[440]
- surveys of market risk practice; and
- the Authority's approach and other Australian regulators' current practice.

1578. In the Draft Decision, the Authority followed the same approach to determine the appropriate estimate of the MRP for Western Power's proposed access arrangement.

The Method of Using Historical Data on Equity Risk Premium

1579. The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets.

1580. It is the current practice of regulators across Australia to estimate the MRP using historical data on equity premia.

1581. Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER after its review of WACC parameters released in May 2009. In the Draft Decision the Authority noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[441] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was

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[439] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 259.

[440] Handley, 2011, "An estimate of the historical equity risk premium for the period for 1883 – 2010", A report for the Australian Energy Regulator, January 2011.

[441] ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998.

based on cash flow measures.[442] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premium.

1582. In its previous regulatory decisions with regard to the estimates of the MRP using historical equity risk premium, the Authority relied on the studies by Associate Professor Handley at the University of Melbourne prepared for the AER. In these studies, Handley used the observed yields on 10 year Commonwealth Government bonds as the proxy for the nominal risk free rate.

1583. As discussed above, the Authority adopted a 5 year term to maturity for the risk free rate. For consistency purposes, in the Draft Decision the Authority considered that it is more appropriate to adopt a 5 year term to maturity for the estimates of the MRP using historical equity risk premium.

1584. The Authority noted that the observed yields on 5 year Commonwealth Government bonds have been available since July 1968. This was also confirmed by Handley in his report to the AER in 2008.[443]

1585. The Authority has constructed a data set of more than 40 years, from 1968 to 2011, inclusive.

1586. An equity market index was used as a proxy for the market return. This data was obtained using a Bloomberg terminal.[444] The series was based on the All Ordinaries Accumulation Index, a value weighted index made up of the largest 500 companies as measured by the market capitalisation that are listed on the Australian Stock Exchange. This index captures a market return comprising dividends and capital gains.

1587. For consistency, the yearly index value is the arithmetic average of the daily closing index values during the corresponding December.

1588. The estimate of Commonwealth Government bond yields (or the risk free rate) is the yields on 5-year term Treasury Bonds. The risk free proxy series from 1968 to 2011 were collected from the Reserve Bank of Australia website.

1589. Figure 18 below presents the estimates of Australia's MRP for the period from 1968 to 2011.

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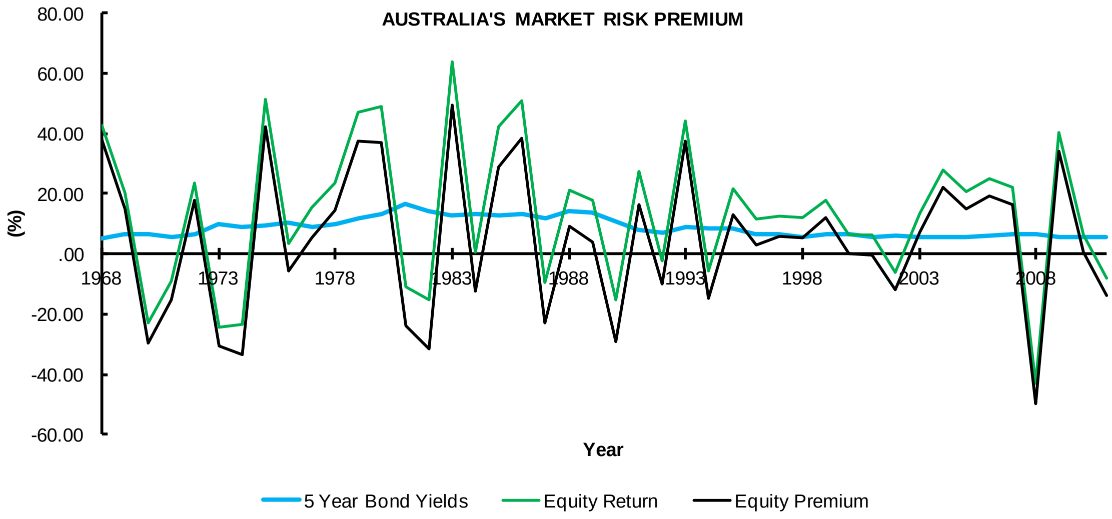
[442] ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998.

[443] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008, p. 4.

[444] The ticker of *ASA30 Index* and the field of *PX_LAST* were used to obtain the data.

Figure 18 Australia's Market Risk Premium, 1968 – 2011, Per cent



Source: RBA, Bloomberg, and Economic Regulation Authority's analysis

1590. Table 168 below presents the estimates of Australia's MRP for the period from 1968 to 2011 over different sub-periods.

Table 168 Estimates of Australian Market Risk Premium, 1968 – 2011, Per cent

Period	No. of years	MRP Per cent	MRP (including imputation credit)[445] Per cent
1968 - 2011	44	4.7	5.2
1980 - 2011	32	4.8	5.6
1988 - 2011	24	3.8	5.0

Source: Economic Regulation Authority's analysis

1591. The analysis presented in Table 168 supported the Authority's view in the Draft Decision that the estimate of the MRP using the historical equity risk premium is within the range of 5 to 6 per cent.

The Survey Method

1592. The Authority also observed that 6.0 per cent is the market risk premium value most commonly used by Australian market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 31 per cent of market

[445] Assumed values of imputation credit were obtained from AER, the Weighted Average Cost of Capital Review, Final Decision, May 2009, Table 7.2, p. 209.

practitioners apply MRP values of more than 6.0 per cent.[446] However, the Authority noted it was cautious about relying on this evidence as these surveys preceded the global financial crisis in 2008.

1593. Surveys in 2009[447] and 2010[448] showed that the average MRP adopted by market practitioners was approximately 6 per cent. These findings are similar to the market surveys prior to the Global Financial Crisis.[449]

1594. In addition, evidence from broker reports (as described below) indicated that the current market practice is to adopt a MRP of approximately 6 per cent. In addition, a recent report from AMP Capital Investors indicated that its forward-looking MRP is lower than 6 per cent.[450]

1595. Anthony Asher conducted a survey of MRP estimates by a number of Australian actuaries in February 2011.[451] There were 58 respondents. Most of the respondents were associated with Investment and Wealth Management, Insurance, Superannuation and Banking. The study reported that, on average, respondents had about 15 years of experience as actuaries. The survey found that the average MRP expected over the next 12 months was 4.7 per cent, while the average expected over the next ten years was 4.9 per cent. The author noted that the standard deviation of the former estimate is 2.5 per cent, and of the latter 2.0 per cent. In these estimates, franking credits were taken into account.

1596. In a recently released article, "Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers" by Pablo Fernandez, Javier Aguirreamalloa and Luis Corre from IESE Business School, University of Navarra, the authors provided an analysis of the results of an international survey on the MRP in March and April 2011. Of the 3,998 survey responses that provided an estimate of the MRP, 40 were from Australia and offered an estimate of the MRP for the Australian equity market. The average of these 40 estimates of the Australian MRP was 5.8 per cent. Of the 40 responses received for Australia, 15 were from academics, 21 from analysts and 4 from managers of companies. The average of the estimates of the MRP received from academics was 6.2, from analysts 5.4 and from managers 6.5. While the overall average for Australia was 5.8, the median was significantly lower, at 5.2.[452]

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446 G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p. 155.

447 Fernandez and Del Campo, Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper, WP-796, May 2009, p. 7.

448 Fernandez and Del Campo, Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School, 21 May 2010, p. 4.

449 For example, see Truong, Partington and Peat (2008), 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p.155. KPMG (2005), *Cost of Capital – Market Practice in relation to Imputation Credits.* Capital Research (2006), *Telstra's WACC for network ULLS and the ULLS and SSS businesses – Review of reports by Professor Bowman,* Associate Professor Neville Hathaway.

450 Oliver, Shane, 2011, *Why are Australian shares lagging? Will it continue?* AMP Capital Investors, January 2011, p. 2.

451 Asher, A. (2011), "Equity Risk Premium Survey: Results and Comments", *Actuary Australia,* 161, July 2011, pp. 13-15.

452 The Australian Competition and Consumer Commission, 2011, *Network,* Issue 41, September 2011, p. 11.

Current Practice by Australian Regulators

1597. The Authority has consistently adopted a point estimate of the MRP of 6 per cent in its regulatory decisions.[453] For the current access arrangement for Western Power, the Authority was of the view that the range of the MRP was between 5 per cent and 7 per cent, and that the point estimate of 6 per cent, being the average of the two, was appropriate.[454]

1598. The AER adopted a MRP of 6 per cent in 2011 in its final decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011.[455]

1599. IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that deriving the MRP from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events, such as the global financial crisis.

1600. The QCA has also used 6.0 per cent for the MRP in its draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction; therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term, and not in response to short-term market fluctuations.

Recent Developments in the Australian Financial Market

1601. The Authority is aware of current developments in the financial markets both in Australia and overseas. However, the Authority is of the view that the investors' expectations of the long-run forward-looking MRP is unlikely to change frequently in response to any developments in the financial markets in the short term.

1602. One of the approaches the Authority has adopted to estimate the MRP is to use a historical return on equity premiums. In that analysis, the Authority has considered a much longer period during which the MRP has been derived, ranging from 20 years to 40 years. In addition, also in the same analysis, the term to maturity of a risk free rate of 5 years is adopted.

1603. In the Draft Decision, after considering all available information and the aforementioned analyses, the Authority took the view that a MRP of 6 per cent is appropriate. The Authority noted this was consistent with the view of some other

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[453] For example, see The Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, p. 137.

[454] The Economic Regulation Authority, 2009, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 4 December 2009, p. 236.

[455] Australian Energy Regulator, June 2011, Final Decision, Envestra Ltd. – Access Arrangement proposal for the Qld gas network, pp. 44-46.

Australian regulators, including the AER, IPART and QCA, that this is the best estimate of a forward-looking long-term MRP.[456]

Western Power's response to the Draft Decision

1604. In response to the Draft Decision, Western Power expressed its concerns to each of the approaches the Authority has relied on to estimate the MRP, namely the analysis using historical data on risk premiums; survey evidence; and current Australian regulatory practice.

1605. Each of these concerns is set out below.

Authority's Analysis Using Historical Data on Equity Risk Premiums

1606. Based on the advice of its consultant, CEG, Western Power submitted that the Authority did not provide any statistical details of the confidence interval around the Authority's estimates of historical averaging periods or whether there were other sub-periods with materially higher average excess returns. Western Power was also of the view that the MRP estimate is very sensitive to the sample period.[457]

1607. For example, Western Power submitted that if 1979 instead of 1980 was chosen as the beginning date for one of the sub-periods, then the estimated average MRP would be around 6.6 per cent. This is due to a 32 per cent excess return in 1979, which is outside the ERA period starting in 1980.

1608. Another example from Western Power is that if 1967 instead of 1968 were chosen as the beginning date for one of the sub periods, then the estimated average MRP would be around 6.0 per cent. This is due to a 40 per cent excess return in 1967 that is not captured by the ERA period that starts in 1968.[458]

1609. Western Power also submitted that its revised MRP of 7.75 per cent, in comparison with its initial submission of 6.5 per cent, recognises the inverse relationship that exists between the risk free rate and the MRP, and is required to account for the significant change in the risk free rate since early 2012.[459]

The Survey Evidence

1610. Western Power submitted that there is no evidence that suggests the Authority has allowed for the shortcomings of the survey method, which have been noted by the Australian Competition Tribunal, in arriving at its estimates of the MRP.

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[456] Australian Energy Regulator, August 2012, Final Decision, *APT Petroleum Pipeline Pty Ltd Access arrangement final decision Roma to Brisbane Pipeline* 2012-13 to 2016-17. Independent Pricing and Regulatory Tribunal, April 2010, Research - Final Decision, *IPART's weighted average cost of capital*. Queensland Competition Authority, May 2012, Final Report – *SunWater Irrigation Price Review: 2012-17*, Volume 1, p. 484.

[457] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 155.

[458] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 155.

[459] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 155.

1611. In respect of the 2009 and 2010 surveys to which the Authority refers, Western Power was of the view that those surveys are also limited because of the following reasons:[460]

- the sample was small.
- it is difficult to know how seriously to take the responses to such surveys when respondents are not responding in any real world context.
- the responses gathered are nothing more than surveys which can only provide a limited insight into actual market risk premium estimates.
- there is no evidence that the estimates of the market risk premium from the surveys are imputation adjusted.

1612. Therefore, Western Power argued that it is not appropriate to rely on survey evidence to determine the MRP.

Australian Regulatory Practice

1613. Western Power argued that other Australian regulatory decisions that have used a MRP of 6 per cent have also used higher estimates of the equity beta and lower credit rating assumptions.[461] As such, the overall rate of returns determined by other Australian economic regulators are much higher compared with the overall rates of return that was reflected in the Authority's Draft Decision.

Summary

1614. On the advice of its consultant CEG, Western Power revised its range for the prevailing MRP to 6.5 per cent to 8.5 per cent. Western Power adopted a value of 7.75 per cent based on a direct estimate of the prevailing MRP relative to the prevailing CGS yields being used to estimate the risk free rate.[462]

1615. Western Power submitted that the practice of estimating the risk free rate and the MRP over different periods is likely to give rise to an inaccurate estimate of the cost of equity, and at the current time when the MRP is above the historical average, this will underestimate Western Power's current cost of equity.

1616. Western Power also submitted that if the Authority prefers to adopt a MRP of 6.0 per cent based on estimates of long run historical average excess returns, then internal consistency requires the adoption of a long run historical average risk free rate estimate, which is to be 3.40 per cent in real terms based on the CEG estimates.[463]

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[460] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 156.

[461] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 156.

[462] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, pp. 157-8.

[463] Western Power, 2012, *Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision*, p. 158.

Public Submissions received in response to the Draft Decision

1617. Grid Australia noted that the Authority has restored the market risk premium back to the level considered appropriate during "normal" financial market periods. However, Grid Australia submit that it is clear from events in financial markets that high levels of uncertainty and risk aversion remain and that the MRP should increase in line with the intuition that the cost of equity should rise during a crisis.[464]

Final Decision

1618. Each of the issues on the estimates of the MRP of 6 per cent raised by Western Power and its consultant, CEG, will be discussed in turn below.

Authority's Analysis Using Historical Data on Equity Risk Premium

1619. The Authority has undertaken its analysis using historical data on equity returns and observed yields on CGS bonds from the following sources:

- Bloomberg, historical series on the All Ords Accumulation Index;[465] and
- Reserve Bank of Australia Yields on Commonwealth Government Securities.[466]

1620. In its analysis of the MRP using historical data on equity risk premium, the Authority applied the same sub-periods as those considered by Associated Professor Handley in his report to the AER. In that report, and others, Associate Professor Handley explained the rationale for his grouping of various years into different sub-periods when estimating the MRP using historical data on equity risk premium.[467]

1621. The Authority relied on the advice of Handley's 2008 study[468] in which he advised that the latest data available are most appropriate and noted that:

> 'The differing start dates of 1883, 1937, 1958 and 1980 correspond to periods of increasing data quality but decreasing sample size.'

1622. This approach by the Authority to sample selection is considered objective in that it followed an expert's independent advice.

1623. Nevertheless, the Authority has considered the estimates of the MRP that are obtained using the sub-periods proposed by Western Power and its consultant CEG.

1624. **Table 169** below presents the estimates of the MRP using historical data on equity risk premium based on sub-periods proposed from Western Power.[469] The MRP for

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[464] Grid Australia, *Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network*, May 2012, pp. 5-6.

[465] Bloomberg ticker: ASA30 Index.

[466] Table 3.23 Yields on Commonwealth Government Securities and F2 - Capital Market Yields.

[467] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008.

[468] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008.

[469] The Authority is unable to extract data for 1976. In the Draft Decision, the Authority indicated that data for the 5-year CGS bond yields starts from 1968.

the period 1979 – 2011, is 6.6 per cent. However, the Authority is of the view that these new outcomes do not alter the Authority's decision to adopt the MRP of 6 per cent as a forward looking estimate in its regulatory decisions.

Table 169 Australian Market Risk Premium, 1967 - 2011

Period	No. of years	MRP Per cent	MRP (including imputation credit) Per cent
1967 - 2011	45	NA	NA
1968 - 2011	44	4.7	5.2
1979 - 2011	33	5.8	6.6
1980 - 2011	32	4.8	5.6
1987 - 2011	25	2.7	4.9
1988 - 2011	24	3.8	5.0

Source: The Economic Regulation Authority's analysis

1625. The Authority is of the view that the selection of sample periods should be purely objective in statistical analysis in order to avoid situations where samples that produce outcomes favourable to parties conducting the analysis are selected. It is not the intention of the Authority to estimate the MRP using different sub-periods in comparison with those set out in Handley's study in 2008.[470] In addition, the Authority is of the view that it is more appropriate that the estimate of the MRP using historical data on equity risk premium should be based on long term historical data, not on a single year with significant variation in the estimate.

[470] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008.

The Survey Evidence

1626. The Authority is wary of basing its estimate of the MRP using only responses from academic surveys. The Authority has not relied only on surveys to determine the appropriate value of the MRP. An estimate of the MRP of 6 per cent is adopted on the basis of various sources of evidence and information of which outcomes from academic surveys is only one source.

1627. However, the Authority is of the view that academic surveys are important in terms of expectation of a long term forward looking MRP for Australia. As a result, some weight (though not determinative weight) should be given to the outcomes of the MRP from academic surveys. It is also noted that the Authority has always considered all surveys available that the Authority is aware of at the time a decision is to be made.

Australian Regulatory Practice

1628. The Authority agrees with Western Power's observation that the estimates of the cost of capital by the Authority are different from the estimates determined by the AER, which is responsible for regulation of network services providers in other states of Australia. The key differences lie in the value of equity beta; the term of a risk free rate; and the approach with which the debt risk premium is determined.

1629. The Authority is not convinced that these differences raise any concerns in relation to the quality of regulatory decisions made by the Authority or by the AER. The cost of capital is estimated to ensure that this figure reflects the prevailing conditions in the market for funds and the risks involved in providing reference services. As the ACT has recently observed "with the estimation of many economic and financial parameters, finding the 'right' value is a process of continual refinement as new models and paradigms emerge and as better data and estimating techniques become available" [471]. Consistent with this approach, current regulatory practices are enhanced and evolved over time and departures from current practices may be appropriate once evidence becomes significant and evident to warrant such a change.

Summary

1630. In summary, based on its own analysis of the estimate of the MRP using 5-years as the term of the nominal risk free rate, various surveys regarding Australia's MRP, and current Australian regulatory practice, the Authority is of the view that the estimate of the MRP using historical data on equity risk premium is the preferred option and that a MRP of 6 per cent is appropriate.

[471] In Application by WA Gas Networks Pty Ltd (no 3) [2012] ACompT 12 at [125].

Relationship between the Risk Free Rate and Market Risk Premium

Western Power's Response to the Draft Decision

1631. Western Power and CEG submitted that if, during the relevant regulatory period, the MRP significantly departs from the long term average, then the method adopted by the Authority in estimating the MRP of 6 per cent will underestimate the overall cost of equity. CEG argued that the current MRP is well above the estimate of 6 per cent using historical data. As such the MRP of 6 per cent adopted by the Authority in its Draft Decision would underestimate the cost of equity for Western Power. In addition, CEG submitted that the empirical evidence suggests that the current MRP is elevated above the long term average value of 6 per cent that is preferred by the Authority. They are therefore of view that the Authority's methodology, using historical data on equity risk premium to estimate the MRP of 6 per cent, underestimates the overall cost of equity for Western Power's access arrangement.[472]

1632. CEG submitted that it has undertaken three empirical methods for estimating the current MRP and equity risk premiums for utilities. CEG made the following conclusions.[473]

- Based on DGM analysis, Bloomberg's estimate of the current MRP for Australian equities is 8.61 per cent.
- Using dividend yields, AMP Capital Investors' estimate of the current MRP is 7.75 per cent in March 2012. CEG submitted that this method was previously relied upon by the AER.
- Using a DGM, an average equity risk premium for utilities is at least 6.73 per cent over the month to 9 March 2012 for the six listed Australian regulated utilities. CEG considered that, given a range of equity beta of 0.8 to 1.0, this suggests an MRP of between 6.73 per cent and 8.41 per cent.

1633. CEG submitted that CGS yields and risk premium are negatively related based on the following two observations.[474]

- Advice to the UK regulators by Smithers and Co, a firm of asset allocation specialists. CEG submitted that Smithers and Co. was of the view that the best estimate was that any rise/fall in the risk free rate would be fully offset by a countervailing rise/fall in investor's required return for risk.
- An observation by CEG on a time series for the equity risk premium for Australian publicly listed equities estimated using the AMP method against the 10-year yield on 10-year CGS.

1634. CEG argued that the Authority's methodology underestimates the cost of equity in current market conditions based on the evidence presented above. CEG also

[472] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. i.

[473] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on pp. i and ii.

[474] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on pp. ii and iii.

submitted that the Authority's method, which involves the transmission of a 1 per cent reduction in CGS yields to a 1 per cent reduction in the cost of equity, is unreasonable, particularly given that CGS yields are currently at historically low levels.

Public Submissions

1635. The Authority did not receive any public submissions on this issue.

The Authority's Assessment

1636. The Authority notes that the key arguments that Western Power and CEG put forward to propose an upward revision to the estimate of the MRP when the risk free rate is at a low level are:

- First, Western Power and CEG are of the view that during the global financial crisis, the nominal risk free rate, CGS bonds as a proxy, is at historical low whereas risk premiums on Australian corporate bonds are still at a very high level. As such, Western Power and CEG argued that there is a "disconnection" between the risk-free assets, such as the observed yields on the CGS bonds, and the risky assets, such as the corporate bonds.
- Second, Western Power and CEG also submitted that, while the observed yields on the CGS bonds, using the nominal risk free rate as a proxy, have significantly decreased during the global financial crisis, the yields on riskier assets, such as observed yields on the State government bonds and the Australian corporate bonds, have been at a high level. As such, Western Power and CEG argued that there is the "disconnection" between the observed yields on the CGS bonds (the nominal risk free rate) and higher risk assets such as the observed yields on the State government bonds and the Australian corporate bonds.

1637. In the Draft Decision, the Authority considered a consultant report to the AER by Professors McKenzie and Partington from the University of Sydney in 2012.[475] The Authority agrees with the logic of the arguments raised by McKenzie and Partington, discussed in the next section below, and on the basis of those arguments rejected the proposal by Western Power and its consultant to adjust the MRP upwards. The Authority is also aware that the AER had not adjusted its estimate of the MRP of 6 per cent in its regulatory decisions in 2012 based on the McKenzie and Partington report.

The observed nominal risk free rate and risk premiums

1638. Professors McKenzie and Partington noted that the observed yields on government securities are currently relatively low. The authors considered the arguments that these low yields are a consequence of a "flight to quality" (that is, to low default instruments), in which investors are particularly attracted to government securities with low default risk. They also argued that these low yields are partly due to the actions of monetary authorities in response to the global financial crisis. In considering the Australian situation, McKenzie and Partington observed that the actions of the RBA are mostly felt at the short end of the yield curve because the

475 McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012.

RBA targets short-term interest rates (the cash rate) to achieve its monetary policy.[476]

1639. McKenzie and Partington observe that the implication of the argument to increase the MRP is that there is a negative correlation between the MRP and the yield on government securities. They note there is empirical evidence of a negative correlation between the nominal government yield and future nominal excess returns in the market, particularly for the government bill yield. However, it is not clear whether this relationship is due to variations in required returns or predictable shocks to realised returns in an inefficient market. If the latter, the relationship would contain no information about the required MRP.

1640. McKenzie and Partington considered that such adjustments would likely be an endless source of debate about the threshold movement in yields that should trigger a revision in the MRP and how large each revision should be.

1641. As a consequence, McKenzie and Partington recommended that if there is to be a switch from an unconditional MRP to an MRP conditioned on government security yields, then there needs to be a strong and clear case to do so and a clear and reliable basis for determining the magnitude of the effect. They concluded that the conditions to adjust the MRP due to a variation of the observed yields from the government securities are not met and, thus, recommended retaining the unconditional MRP of 6 per cent.[477]

1642. The Authority agrees with the expert views of McKenzie and Partington and has decided that the estimate of the MRP should not be conditional on variations on observed yields from the CGS.

The observed nominal risk free rate and risky assets such as the State government bonds and corporate bonds

1643. The second argument raised by Western Power and CEG for a higher MRP was that there are substantially increased yields on risky debt because of widening credit spread and so the MRP must have correspondingly increased.

1644. However, Professors McKenzie and Partington argued that comparing the yield on debt and the MRP is problematic.

1645. Professors McKenzie and Partington considered that the widening credit spreads during the economic downturn were substantially driven by increasing concern about the risk of default and a liquidity issue in debt markets caused by extreme concerns about default risk. Thus, it was a combination of default premiums and liquidity premiums that drove up returns in debt markets.[478] They argued that an increase in credit spreads due to increased default risk does not automatically require a shift in the MRP. Professors McKenzie and Partington emphasised that the MRP is an expected return, whereas the yields on debt are a promised return. The promised return is only the same as the expected return for debt where there is

[476] McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012, p. 9.

[477] McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012, p. 11.

[478] McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012, p. 21.

no default risk; however, when there is a default risk, then the promised return is higher than the expected return. As such, Professors McKenzie and Partington were of the view that, since the debt yield and the MRP measure different things, they are not constrained to move in a similar fashion and comparisons between them can be misleading.[479]

1646. Professors McKenzie and Partington considered that it might reasonably be expected that the default risk component of the credit spread increased as a result of the global financial crisis due to a changed assessment of default risk. An increase in default risk on debt may spill over into equity markets via a reduction in expected cash flows and dividends, which will result in a decrease in share prices. They also considered that it is likely that the crisis environment of the GFC led to an increase in investor risk aversion and to an increased perception of systematic risk. As such, it is likely that there was some increase in the MRP at that time. McKenzie and Partington refer to the survey evidence of Graham and Harvey (2010), Fernandez (2011) and Asher (2011) to conclude that the MRP has since returned to normal levels, or perhaps even lower levels.[480]

The 2012 Study by the Authority: Granger Causality Test

1647. The Authority conducted a Granger causality test to test the proposition that the changes in the nominal risk free rate causes changes in the MRP.

1648. The Granger causality test assumes that changes in variable X causes changes in variable Y based purely on precedence within a time series. If there is a relationship between changes in X and Y, and X precedes Y then X causes Y based on the assumption that the future cannot predict the past.

1649. Two equations are developed to test the existence of causality between the risk-free rate and the MRP.

$$\text{Yield Change}_t = \sum_{i=1}^{n} \alpha_i \text{ERP}_{t-i} + \sum_{i=1}^{n} \beta_i \ \text{Yield Change}_{t-j} + \varepsilon_{1t} \qquad (1)$$

$$\text{ERP}_t = \sum_{i=1}^{n} \lambda_i \text{Return}_{t-i} + \sum_{i=1}^{n} \delta_i \text{Yield Change}_{t-j} + \varepsilon_{2t} \qquad (2)$$

1650. In the context of bond yields (Yield Change) and equity return premiums[481] (ERP) equations (1) and (2) are regressed to determine whether (in aggregate) the coefficients on the lagged values of the respective variables are statistically different from zero. That is, the following hypotheses are tested:

$$H_0 : \alpha_1 + \alpha_2 + ... + \alpha_n = 0 \qquad (3)$$

[479] McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012, p. 22.

[480] McKenzie and Partington, 2012, *Supplementary Report on the Equity Market Risk Premium,* Report to the AER, 22 February 2012, p. 23.

[481] The equity return premium is the difference between the observed daily return and observed daily bond yield change, as opposed to the market risk premium which is the difference between the equity return and the bond yield over a longer time horizon.

$$H_0 : \delta_1 + \delta_2 + ... + \delta_n = 0 \qquad (4)$$

1651. An assumption is made on the number of lagged values of each variable to include in the regression. For example, if the data is daily and it is expected that returns will only be significantly affected by changes in bond yields for the previous day, then the lag will be one. However, if it is expected that the ERP will be significantly affected by changes in yield on each day over the past business week, then the lag will be designed to include all five days of the week.

- If the null hypothesis (3) is rejected, that is, alpha is statistically different from zero, changes in the ERP Granger-cause changes in Yield.
- If the null hypothesis (4) is rejected, that is, delta is statistically different from zero, changes in Yield Granger-cause the ERP.
- Rejecting both null hypotheses is evidence of feedback or bilateral Granger causality. That is, both variables Granger-cause each other.
- Failure to reject both null hypotheses suggests that the variables are independent.

1652. To test for Granger causality between bond yields and equity market returns in Australia, the daily (trading day) yields on 10-year Australian Government Bonds and daily closing prices for the All Ordinaries Index were sourced from Bloomberg. It is noted that the daily closing prices were adjusted for changes on days for all normal and abnormal cash dividend types except omitted, discontinued, deferred or cancelled dividends and so do not incorporate the effect of dividend drop-offs.

1653. Changes in the yield (Yield Change) were constructed by taking the natural log of the daily yield, b_t, divided by the previous day's yield b_{t-1}. This means that $Yield\ Change_t = \ln(b_t / b_{t-1})$. Similarly, the equity market returns (returns) are constructed as $\mathrm{Re}turn_t = \ln(P_t / P_{t-1})$.

1654. The daily equity return premium is defined as the difference between the equity market return and the bond yield return, which is defined as below.

$$ERP_t = \ln\left(\frac{P_t}{P_{t-1}}\right) - \ln\left(\frac{b_t}{b_{t-1}}\right)$$

1655. Table 170 below presents the summary of data used in this study for the period from 1983 to 2012.

Table 170 Granger Causality Test, MRP versus Risk Free Rate, Oct 1983 – February 2012

Variable	Ticker	Numbers of observations
10-year CGS yields	GACGB10	7,215
All Ordinaries Accumulation Index	ASA30	7,215

Source: Bloomberg

1656. Regression equations as presented in equations (1) and (2) use the Granger causality test function of the MSBVAR package in R. The lag was set at one day to test if changes in bond yields Granger cause changes in the equity return premium the next day and vice versa.

1657. Table 171 below presents the findings of the augmented Dickey Fuller Unit Root Tests (No Drift or Trend). Both series exhibit a t-statistic greater than two. As such, the test rejects the null hypothesis of a unit root at the five percent level of significance. This implies that the series are stationary and are suitable to conduct the Granger causality Test.

Table 171 Augmented Dickey Fuller Unit Root Tests

Series	T-Stats
Yield Change	-39.3792
Equity Risk Premium	-42.3983

Source: Economic Regulation Authority's Analysis

1658. The null hypotheses (3) and (4) are rejected even at the one percent level of significance. These results suggest that there is feedback or bilateral causality between changes in yield and the equity return premium, as presented in Table 172 below.

Table 172 Granger Causality Test Results

Coefficient	F-Stats	P-Value
$\sum_{i=1}^{n} \alpha_i$	112.5331	0.0000
$\sum_{i=1}^{n} \beta_i$	14.0874	0.0002

Source: Economic Regulation Authority's Analysis

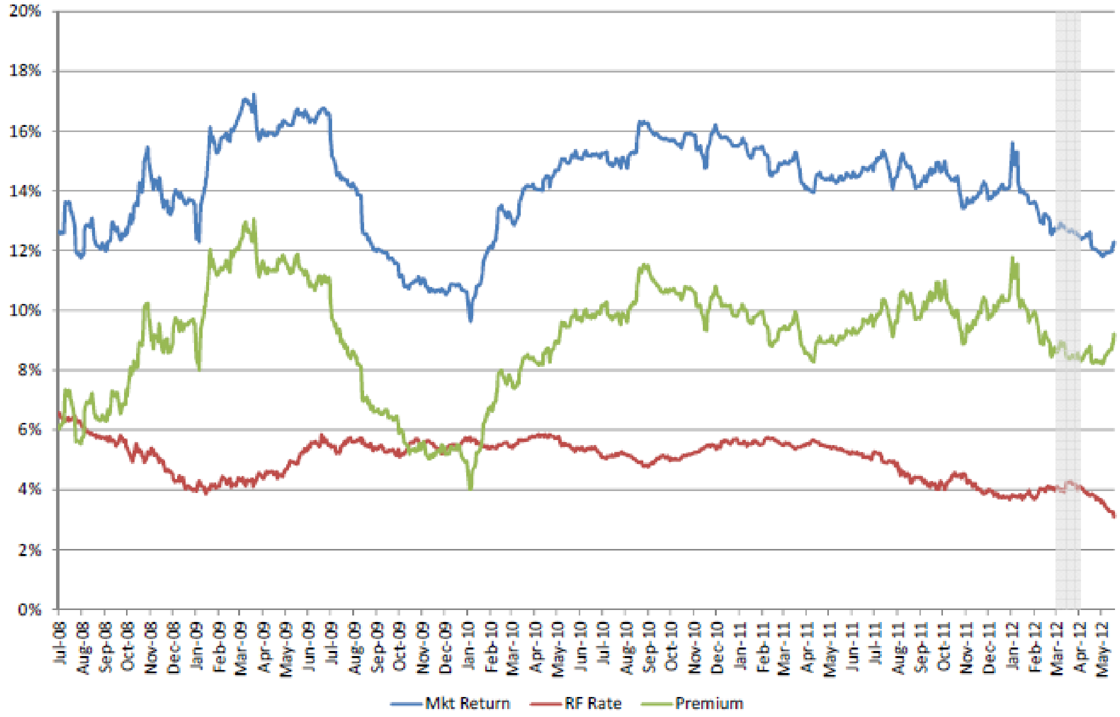
1659. On the above analysis, the Authority is of the view that the Granger causality test suggests that there is feedback between changes in bond yields and equity return premiums in Australia. Intuitively, one would assume that this would be the case as significant movements in the return from one asset vis-à-vis a given value of the other would change the relative attractiveness of each asset and at times cause investors to move funds between them.

1660. In conclusion, the Authority considers that there is no evidence based on its statistical analysis to support the view that the decreased yields on the CGS bonds have caused an increase in the estimate of the MRP.

Western Power's revised Market Return of 8.5 per cent as an upper bound

1661. The Authority notes that the upper bound of the MRP of 8.5 per cent was based on Bloomberg's estimates of the Australian market return, as presented in Figure 19 below. The upper bound of the MRP of 8.5 per cent was submitted by Western Power on the advice of its consultant CEG who concluded that, for the averaging period of 20 trading days between 5th and 30th March 2012, the average market return on equity was 12.71 per cent and the average risk free rate was 4.10 per cent. As such, the market return was 8.6 per cent, as presented below.[482]

Figure 19 Bloomberg's Estimates of the Australian Market Return



Source: Bloomberg

Source: *ECG, Internal Consistency of Risk free rate and MRP in the CAPM, Prepared for Western Power, Figure 3, page 9.*

1662. Using the same evidence presented by Western Power above, the Authority notes that the MRP was only 4 per cent based on Bloomberg's estimate in 2009 when the Final Decision for Western Power's current access arrangement was released. In that decision, the Authority adopted the MRP of 6 per cent even though the nominal risk free rate was as high as 5.51 per cent. Consistent with the Authority's position in 2009, the Authority is of the view that the MRP of 6 per cent is a long term forward looking estimate and should not be revised downwards (in the case of December 2009 when the risk free rate was high) or upwards (in the case of July 2012 when the risk free rate was relatively low).

Summary

1663. The Authority is not convinced that Western Power and its consultant CEG have provided any convincing arguments to support an upwards adjustment of the estimate of the MRP when the observed yields on CGS are at historically low levels. This conclusion is based on expert advice from Professors McKenzie and Partington from the University of Sydney for the AER in 2012 as well as statistical analysis undertaken by the Authority.

[482] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, p. 9.

Equity Beta

Western Power's Initial Proposal

1664. On the basis of SFG's advice, Western Power submitted that two things determine the value of equity beta for a particular firm:

- the type of business that the firm operates; and
- the amount of financial leverage (gearing) employed by the firm.

1665. Western Power also submits that transmission and distribution companies have business activities that are below-average risk, but that their financial leverage is much higher than average, so that the two components of equity beta operate in different directions and will tend to offset one another.

1666. As a result, Western Power proposes that the appropriate *a priori* expectation of the equity beta for transmission and distribution companies such as Western Power is no different from that of the average firm, which is 1.0.[483]

1667. As the submission from Western Power is based on the advice of its consultant, SFG, the Authority considers that it is necessary to respond directly to SFG's advice.

1668. The key arguments put forward in SFG's advice to Western Power are summarised below.

1669. First, an appropriate default equity beta estimate is 1.0. SFG argues that there is no reason for an *a priori* view that the equity beta for an electricity transmission or distribution firm is less than one.

1670. Second, the regulatory estimate of equity beta of 0.8 that has been adopted by the Authority and the AER is statistically unreliable.

1671. Third, the regulatory estimate of equity beta of 0.8 is commercially implausible, because:

- the approach on which the estimate of 0.8 is based produces implausible estimates over time;
- the required return on unlevered equity cannot be lower than the required return on debt;
- the required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms; and
- for non-resident investors the implied return on levered equity is materially lower than the implied return on debt.

1672. Fourth, SFG submits that a NFIT under the Code requires the regulator to perform an *ex post* assessment of the efficiency of capital expenditure before new investment can be included in the asset base. As such, there is a risk for Western

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[483] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 263-4.

Power that some capital expenditure will be disallowed. SFG argues that comparable companies regulated under the National Electricity Rules face no such risks.

1673. Western Power's second consultant on the issue, Ernst & Young, submits that the requirement to undertake an *ex post* assessment of capital expenditure, and the fact that the Authority has previously exercised this provision in the way that it has, means that investors are exposed to a significant risk that invested capital may not be recovered. Ernst & Young submits that there is evidence to suggest that this is systematic risk, and as such should be compensated. As a result, Ernst & Young proposes that the equity beta for Western Power should be above 0.8.

Draft Decision

1674. The Authority considered each of the issues raised by Western Power and its consultants in turn below.

A Priori *View that the Equity Beta for an Electricity Transmission or Distribution Firm is 1.0*

1675. SFG submits that the business activities of regulated electricity network distribution and transmission businesses have less systematic risk than average, however, these businesses have much higher financial leverage than the average firm (assumed gearing of 60 per cent for regulated businesses versus gearing of 30 per cent for the average firm).

1676. SFG argues that the two effects operate in different directions and that there is no compelling *a priori* reason to suggest which of these effects should dominate the other.

1677. Consequently, SFG submits that the appropriate *a priori* expectation is that the equity beta for these regulated businesses is no different from that of the average firm, which is 1.0.[484]

1678. The Authority notes this argument was raised in the AER WACC review in 2008/2009.

1679. The Authority considers that it is generally accepted that the business risks faced by regulated electricity network distribution and transmission businesses are lower than those of the average firm. Western Power and SFG agree with the Authority on this point.

1680. The Authority also agrees that the assumed gearing level of 60 per cent for regulated electricity network distribution and transmission businesses is higher than that of the average firm. However, for reasons discussed below, the Authority does not agree that the financial risk of the regulated businesses is higher than that of the average firm. This means that the Authority does not agree that regulated businesses face higher exposure to financial risk than the average business due to their higher gearing.

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[484] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, pp. 11-12.

1681. The Authority agrees with the AER's view that, unlike the unregulated businesses, the cost of debt, including the debt risk premium and the risk free rate for regulated businesses, is based on prevailing market conditions at the time of the regulatory decisions.[485] The Authority is of the view that this "pass-through" nature of borrowing costs is likely to reduce exposure to financial risk faced by regulated businesses.

1682. Overall, the Authority agrees that, with regard to regulated electricity network distribution and transmission businesses, a lower business risk results in a lower equity beta compared with the market. Also, the higher gearing level leads to a higher equity beta in comparison with the market. These two effects may act to offset each other. However, the Authority is of the view that it is premature to conclude that the appropriate *a priori* expectation of the equity beta for transmission and distribution businesses is at the market level of one.

1683. As the net effect on the equity beta is unclear, the Authority is of the view that conceptual considerations as presented by Western Power and SFG are not a sufficient ground on which to form a conclusive view on the equity beta for transmission and distribution businesses.

1684. In conclusion, based on the above reasoning and analysis, the Authority is not convinced by the case put forward by Western Power and SFG, that the appropriate *a priori* expectation of the equity beta for transmission and distribution companies such as Western Power is no different from that of the average firm, which is 1.0. The Authority is of the view that the exposure of regulated electricity network distribution and transmission businesses to business risk and financial risk overall is less than that of the average business or the market. As such, the Authority considers that the equity beta for regulated electricity network distribution and transmission businesses should be less than one.

Regulatory estimate of equity beta of 0.8 is statistically unreliable

1685. The Authority notes that this argument is the same argument that SFG submitted to the AER during the WACC Review in 2008.[486]

1686. The AER and its consultant on the issue, Professor Henry from the University of Melbourne, responded to SFG's comments at length in the AER's Final Decision on its WACC Review released in May 2009.[487] The Authority agrees with and adopts the AER and Henry's responses. The Authority is of the view that the response of the AER and Henry remains equally applicable to SFG's arguments in 2012 for the purposes of this decision.

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[485] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, pp 193-4.

[486] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, p. 187.

[487] The Australian Energy Regulator, 2009, Final Decision, "Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", May 2009, pp. 279-309.

The approach on which the 0.8 is based produces implausible estimates over time and non-sensible outcomes in other industries

1687. SFG submits that one test of the reliability of Professor Henry's approach, which the Authority and the AER have relied on to estimate the equity beta, would be to examine the characteristics of the equity beta estimates produced over a period of time. SFG considers that if the approach produced economically reasonable and relatively stable estimates over time, there would be more confidence in the veracity and reliability of the results, and *vice versa*.[488]

1688. SFG submits that it cannot examine the performance of Henry's technique over time due to data unavailability. As such, SFG conducts the analysis for five different industries: commercial services; energy; health equipment; media; and metals mining.[489] Within each industry, SFG selected five comparable firms that had stock return and annual report data available from December 1988 to December 2006, to avoid the effect of the global financial crisis in 2008/09.

1689. Based on its analysis, SFG submits that the approach on which the AER's estimate is based produces non-sensible outcomes in other industries.[490]

1690. The Authority notes that Henry's approach carefully set out the rationale for the companies to be included in the sample to which the method is applied. The five companies included in Henry's sample represent the best comparator to the efficient benchmark network service provider. In addition, Henry's approach covers the period from 2002 to 2008.

1691. The Authority is unclear about SFG's rationale in its selection of industries to confirm the veracity and reliability of Henry's approach to estimating equity beta. SFG does not provide any justification for its selection of the five industries, and the Authority considers that only energy industries are sufficiently linked to the utilities sector in Australia, on which the Henry approach was based.

1692. An interesting observation from SFG's results is that, among all of the findings SFG uses to support its argument (that the approach on which the AER's estimate is based produces non-sensible outcomes in other industries), none of them comes from the energy industry.

1693. As a result, the Authority is of the view that SFG's empirical work on other industries to test the validity of Henry's method is inappropriate.

1694. The Authority has conducted its own analysis using Henry's method with an extended data set until 2011. The Authority is informed by this analysis that the estimates of equity beta are quite consistent with Henry's estimates. Further details about this new analysis are discussed in Appendices 6, 7, and 8.

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[488] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 26.

[489] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 27.

[490] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 26.

The required return on unlevered equity cannot be lower than the required return on debt

1695. SFG submits that, the unlevered equity beta (or asset beta) of 0.32[491] is equivalent to an equity beta of 0.8 with the assumed gearing level of 60 per cent. Together with the assumed risk free rate of 5 per cent and the MRP of 6 per cent, the return to unlevered equity beta would be 6.9 per cent.[492]

$$\begin{aligned} r_e &= r_f + \beta_a \times MRP \\ &= 5\% + 0.32 \times 6\% = 6.9\% \end{aligned}$$

1696. SFG then submits that the debt holder in the benchmark firm requires a return of 8.2 per cent, assuming the debt risk premium associated with a BBB+ credit rating of 3.179 per cent, as determined in the Authority's Final Decision on WA Gas Networks, released in February 2011.

$$\begin{aligned} r_d &= r_f + DRP \\ &= 5\% + 3.179\% = 8.2\% \end{aligned}$$

1697. SFG then concludes that it is impossible for the required return on equity to be lower than the required return on debt in the same firm, because debt has a first-ranking claim over the cash flows of the firm (i.e. debts are entitled to be paid in full before any residual cash flows are paid to the equity holders).[493]

1698. The Authority is of the view that SFG is not comparing "like with like" in this exercise.

1699. First, SFG converts the equity beta of 0.8 into the asset beta of 0.32, with the assumed gearing of 60 per cent for debt.

$$\beta_e = \beta_a \times \left(1 + \frac{D}{E}\right)$$

$$0.8 = 0.32 \times \left(1 + \frac{60}{40}\right)$$

1700. Second, SFG uses the asset beta of 0.32 in lieu of the equity beta in the CAPM to calculate the required rate of return for the unlevered equity beta (i.e. the asset beta) of 6.9 per cent, as presented in paragraph 1695. This implies that debt is zero, and that businesses are fully financed by equity.

1701. The Authority is of the view that the consequence of using the unlevered equity beta (or asset beta) in the CAPM to derive the required rate of return on equity is that the demand for debt is assumed to be zero. In this hypothetical scenario, there

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[491] The Authorities view is that this is incorrect; the asset beta should be replaced by the equity beta.

[492] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 28.

[493] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power,* Report prepared for Western Power, July 2011, pp. 28-9.

is no business debt because businesses are fully funded by equity. There is only debt issued by the government, with the rate of return known as the risk free rate. The risk free rate compensates investors for inflation risk (i.e. the time value for money) and liquidity risk, but not for any risk premium (the premium paid to investors for bearing a higher level of risk, for example, investing in corporate bonds instead of government bonds). As such, if companies are fully funded by equity, the debt risk premium should be zero, and the cost of debt should be equal to the risk free rate of 5 per cent, which is also lower than the cost of equity. Alternatively, it may be argued that if companies are fully funded by equity, then there is no demand for debt. In this circumstance, the concept of the cost of debt, or the debt risk premium is not relevant.

The required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms

1702. The Authority notes that SFG has used the same argument, with the same figures as it used in advice provided to WAGN and to the Dampier Bunbury Natural Gas Pipeline. All these arguments are now reproduced in its advice to Western Power with regard to the estimate of equity beta.

1703. SFG submits that if investors expect a dividend yield of 9 per cent (on average) from a comparable firm, and if the expected return in the form of capital gains is considered to be in the range of 2.5 per cent and 3.5 per cent per year, then the combined return on equity is in the range of 11.5 per cent and 12.5 per cent.[494]

1704. With regard to a dividend yield, a key component in the combined required rate of return, SFG has used dividend forecasts from broker research reports. Table 173 below presents SFG's findings, using research reports' forecasts.

Table 173 Average Dividend Yield by Firm and Year (per cent)

Business	Forecasts (Per cent)			Average
	2011	2012	2013	
APA (APA Group)	8.46	8.87	9.30	8.88
DUE (Duet Group)	11.94	12.01	12.03	12.00
ENV (Envestra Limited)	9.56	9.56	9.63	9.59
HDF (Hastings Diversified)	6.36	6.48	6.39	6.41
SKI (Spark Infrastructure)	8.02	8.16	8.35	8.18
SPN (SP Ausnet)	9.00	9.20	9.40	9.20
Average	**8.87**	**9.02**	**9.14**	**9.01**

Source: Table 5, page 30, SFG (2011).

[494] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 30.

1705. Table 173 indicates that the average of the dividend yield forecasts for a sample of six companies above for 2011 is 8.87 per cent.

1706. Dividend yields for the above companies were paid in 2011, so they are actual figures and publicly available. The Authority has collected the actual dividend payments for the entire year 2011 for the above companies from the Australian Stock Exchange. The dividend yield is defined as the ratio between total dividend payouts in the year and the closing price of the share as at 31 December 2011.

1707. Table 174 compares dividend yields forecast by research reports used by SFG with actual dividend yields for the six companies in 2011.

Table 174 Comparison between forecast and actual dividend yields (Per cent)

Business	Dividend Yields (Per cent) in 2011		
	Forecast	Actual	Difference
APA (APA Group)	8.46	3.99	4.47
DUE (Duet Group)	11.94	10.29	1.65
ENV (Envestra Limited)	9.56	7.96	1.6
HDF (Hastings Diversified)	6.36	4.88	1.48
SKI (Spark Infrastructure)	8.02	8.38	-0.36
SPN (SP Ausnet)	9.00	8.51	0.49
Average	**8.89**	**7.34**	**1.56**

Source: Economic Regulation Authority's analysis

1708. The above analysis indicates that the average forecast dividend yield for 2011 of 8.89 per cent for the above sample is overestimated by 1.56 per cent, in comparison with the actual dividend yield of 7.34 per cent. This overestimation is around 18 per cent (1.56 per cent divided by 8.89 per cent) and is significant enough for one to be concerned about the accuracy of such forecasts.

1709. As previously indicated in its decisions for WAGN and DBNGP, the Authority maintains its position that, given the poor record of economic forecasting on which the brokers' research reports are based,[495] it is inappropriate to use brokers' research reports to derive an estimated cost of equity for any purpose.

[495] For example, see Fildes, R. and Makridakis, S. (1995). The impact of empirical accuracy studies on time series analysis and forecasting, *International Statistical Review,* 63, 3, 289-308; and Hendry, D. and Clements, M. (2003). Economic forecasting: some lessons from recent research, *Economic Modelling,* 20, 301-329. For example, Clements and Hendry derive the following nine sources of forecast error as a comprehensive decomposition of deviations between announced forecasts and realised outcomes:

- shifts in the coefficients of deterministic terms;
- shifts in the coefficients of stochastic terms;
- mis-specification of deterministic terms;
- mis-specification of stochastic terms;
- mis-estimation of the coefficients of deterministic terms;
- mis-estimation of the coefficients of stochastic terms;

New Facility Investment Test

1710. Western Power and both of its consultants, SFG and Ernst & Young, submit that NFIT is an *ex post* assessment of the efficiency of capital expenditure before new investment can be included in the capital base. Western Power argues that there is a risk that some of its capital expenditure will be disallowed and, consequently, no return will be generated from it.

1711. Western Power and its consultants submit that this type of risk is systematic in nature. They argue that this risk should be compensated via the equity beta.

1712. The Authority notes that the entire WACC framework is developed and applied to the efficient benchmark network service provider. Consequently, no firm-specific risk will be considered appropriate. In addition, Western Power may ask for a pre-approval from the Authority prior to any investment under section 6.71 of the Access Code. NFIT under the Code is a mechanism to ensure that capital expenditure to be incurred by Western Power is efficient. It is not designed to introduce higher levels of risk for Western Power in comparison with other regulated businesses in Australia.

1713. In conclusion, the Authority is of the view that no compensation via equity beta should be allowed with regard to the NFIT.

Estimates of the equity beta

1714. The Authority is of the view that the Sharp-Lintner CAPM is the most widely used form of the CAPM for estimating the cost of equity by the regulators and practitioners. The Authority adopts the Sharp-Lintner CAPM to estimate the cost of equity for Western Power's access arrangement.

1715. The central implication of the CAPM is that the contribution of an asset to the systematic risk of a portfolio of assets (also known as beta risk) is the correct measure of the asset's risk and the only systematic determinant of the asset's return. There are two main components of the CAPM: the market portfolio M, and beta risk β of a portfolio, which correlates the portfolio to the rise and fall of the market.

1716. Under the CAPM model, the total risk of an asset can be divided into systematic and non-systematic risk. Systematic risk is a function of broad macroeconomic factors (such as interest rates) that affect all assets and cannot be eliminated by diversification of the businesses asset portfolio. In contrast, non-systematic risk relates to the attributes of a particular asset, where this risk can be managed by portfolio diversification.

1717. In the CAPM, the equity beta value is a scaling factor applied to the market risk premium to reflect the relative risk to equity funds in the particular firm or activity in question.

1718. As stated in paragraph 1682, the Authority is of the view that conceptual considerations as presented by Western Power and SFG do not provide a sufficient

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- mis-measurement of the data;
- changes in the variances of the errors; and
- errors cumulating over the forecast horizon.

basis to form a conclusive view on the equity beta for transmission and distribution businesses.

1719. As a result, the Authority considers that, when ascribing a value to the equity beta, primary reliance should be placed on capital market evidence and statistical estimates of beta values, where these are available for comparable businesses.

1720. In its 2009 WACC review for electricity transmission and distribution network service providers, the AER, with the assistance of Associate Professor Henry of the University of Melbourne, established a sample of Australian businesses, comprising gas-only network businesses, one electricity-only network business, network businesses active in both electricity and gas, and general utility businesses. Given the limitations of available Australian data, the AER considered that gas network businesses could be considered as reasonable but not perfect comparators to electricity network businesses, given that both industries involve the transportation of energy.[496]

1721. Based on empirical work by Henry,[497] the AER concluded that a reasonable range of the equity beta for a gas or electricity distribution network was between 0.4 and 0.7. The AER also considered the need for regulatory certainty and adopting a conservative approach in estimating the equity beta, commensurate with prevailing market conditions and the risks involved in providing reference services. On this basis, the AER considered that a value of 0.8 provides the best estimate of the equity beta arrived at on a reasonable basis for gas and electricity transmission and distribution networks.[498]

1722. In the Final Decision for the current access arrangement for Western Power, released in December 2009, the Authority adopted a range for the estimate of equity beta of 0.5 to 0.8. The Authority was of the view that this range was consistent with the analysis presented by the AER in its 2009 WACC Review, based on Henry's empirical study. In Henry's study, an estimate of the equity beta fell within the range of 0.41 and 0.68. The AER acknowledged that estimate of equity beta may exhibit a high level of imprecision. As such, the AER adopted the estimate of equity beta of 0.8 in the Final Decision on the WACC Review in 2009.

1723. The Authority conducted its own analysis of the estimates of the equity beta. The Authority has used the same approach adopted by Henry in his study, using an updated data set until October 2011.

1724. The Authority is informed by its analysis that the estimates of the equity beta using weekly data range from 0.2168 to 1.3378 with a mean of 0.5204 and median of 0.4261.

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496 The main sample consisted of: AGL (2002 to 2005); Alinta (2002 and 2007); Alinta Network Holdings Pty Ltd (2003 to 2006); Country Energy (2002 to 2006); Diversified Utility and Energy Trusts (2003 to 2008); ElectraNet Pty Ltd (2002 to 2008); Energy Australia (2002 to 2006); Envestra Ltd (2002 to 2008); Ergon Energy Corporation (2002 to 2008); ETSA Utilities (2002 to 2008); GasNet Australia (Operations) Pty Ltd (2002 to 2007); Integral Energy (2002 to 2006); SP AusNet Group (2006 to 2008), and SPI PowerNet Pty Ltd (2002 to 2005).

497 Henry, Olan (2008), Econometric Advice and Beta Estimation, Department of Economics, the University of Melbourne, 28 November 2008.

498 See for example: Australian Energy Regulator 2009-10, Final decision: WACC review, May 2009; or Powerlink Transmisison determination, 2012-13 to 2016-17 (Draft Decision, 29 November 2011, p. 33).

1725. The results of the Authority's analysis, using the extended dataset to October 2011, can be summarised as below:

- the estimates of the equity beta using monthly data range from 0.0675 to 0.9688, with a mean of 0.4569 and median of 0.4253; and
- the estimates of the equity beta using weekly data range from 0.2168 to 1.3378, with a mean of 0.5204 and median of 0.4261.

1726. As a crosscheck, the Authority has confirmed that these updated estimates are consistent with the estimates from Henry (2009).

1727. Due to a high level of imprecision of the estimate of the equity beta, the Authority was of the view in the Draft Decision that these results do not justify a change to its decision about the estimates of the equity beta adopted in the current access arrangement of 0.5 and 0.8.

1728. In the Draft Decision, the Authority was of the view that the point estimate of the equity beta of 0.65, being the average of the lower and upper bounds of the adopted range, was reasonable for the following reasons:

- it is at the upper end of the empirical estimates by Henry (2009) and the Authority (2011) which indicated that the mean and median values of the equity beta fall within the range of 0.5 to 0.65;
- it is the midpoint of the estimated equity beta adopted in the current access arrangement; and
- the midpoints are taken to reduce the undesired effects of outliers, such that their effect is averaged out.

Western Power's Response to the Draft Decision

1729. In response to the Draft Decision and based on CEG's advice, Western Power revised its equity beta to 0.8 – a departure from its initial submission of an equity beta of 1.0, which was based on SFG's advice.[499]

1730. Submissions from Western Power on the issue in response to the Authority's Draft Decision were based on the advice it received from two consultants: CEG and SFG. There are two key issues arising from these submissions: (i) general criticisms from SFG on the econometric model that the Authority and the AER have relied on to derive the equity beta; and (ii) technical econometric issues from the Authority's approach to estimating equity beta.

SFG's General Criticisms to the ERA/AER framework

1731. Based on SFG's advice,[500] Western Power submitted that the Authority's estimate of equity beta of 0.65 is commercially implausible, because:

- the Authority's methodology produces results in other industries that vary wildly over time;

[499] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 160.

[500] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 158.

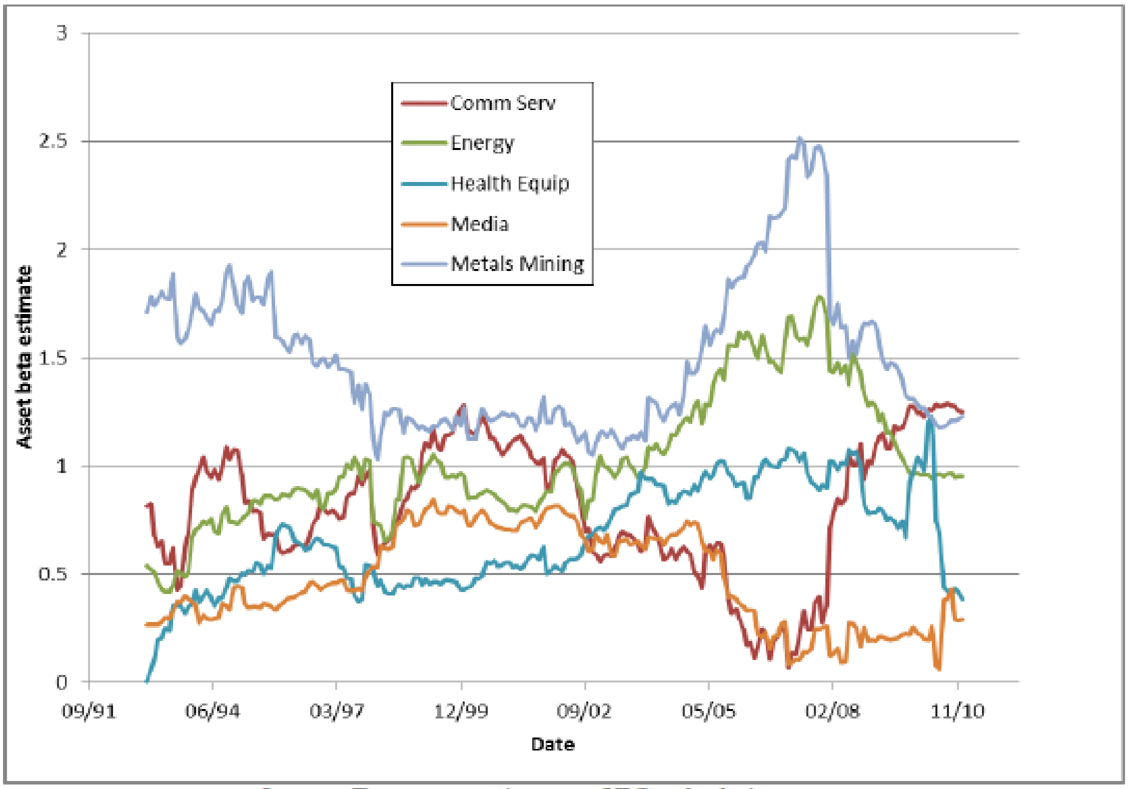
- the required return on unlevered equity cannot be lower than the required return on debt; and
- the required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms.

1732. SFG raised three practical issues with the estimate of equity beta adopted in the Draft Decision. Each of these three issues is addressed in turn below.

The approach on which the 0.65 is based produces implausible estimates over time and non-sensible outcomes in other industries and for the US energy sector

1733. SFG conducted its analysis by applying the approach adopted by the AER and the Authority to other industries and argued that the approach produces non sensible outcomes in other industries. In response to the Authority's Draft Decision, SFG submitted that its analysis is now updated to include data to the end of 2010. SFG submitted that the Authority's approach to estimating equity beta produces nonsensical outputs over time when applied to other industries. Figure 20 below is reproduced from the SFG's study.[501]

Figure 20 SFG's analysis on Time series variation in regulatory methodology beta estimates



Source: Datastream, Aspect. SFG calculations.

Source: SFG (May 2012), Figure 2 on page 14.

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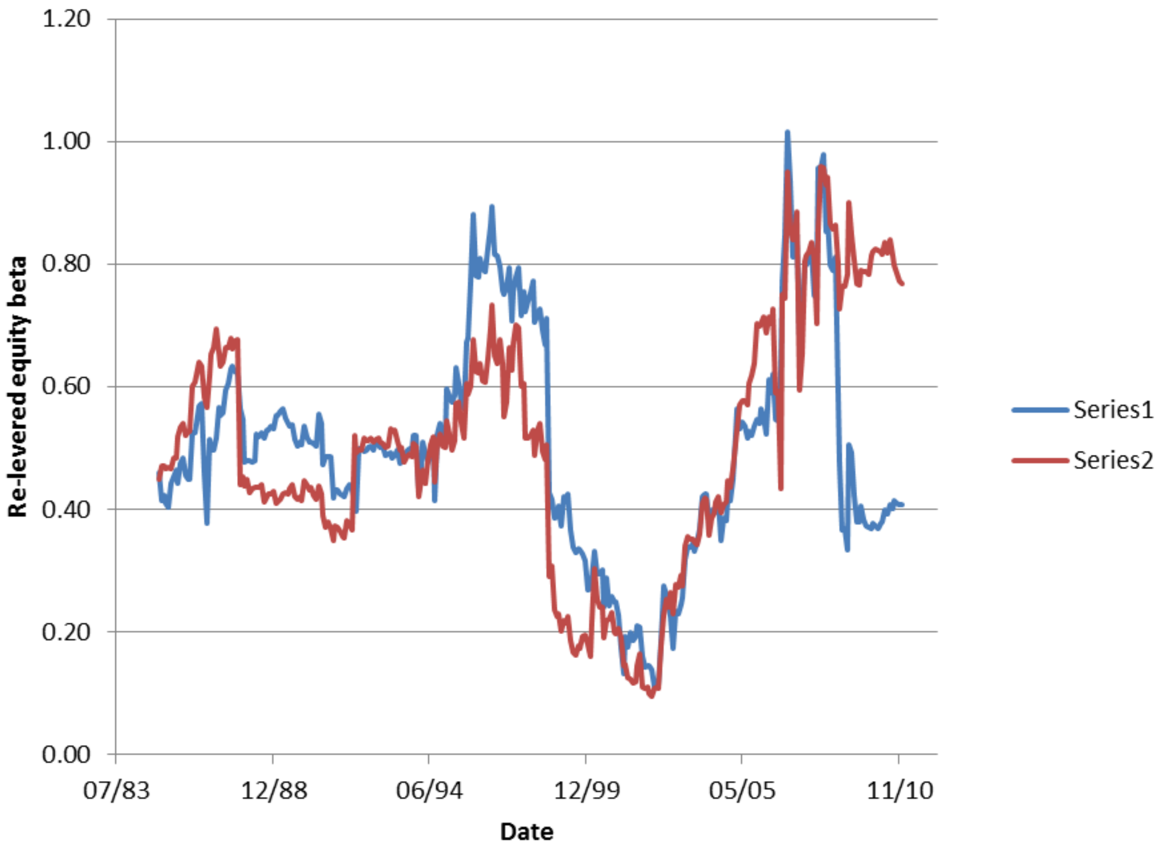
[501] Strategic Finance Group, 2012, *Estimating Beta: Reply to Draft Decision*, Report prepared for Western Power, 29 May 2012, p. 14.

1734. SFG also submitted that the same approach applied to two samples of US utilities drawn from among the US firms. SFG noted that these two samples of US utilities has been used by the AER in the AER's set of foreign comparables in its WACC Review in 2009. Figure 21 below is reproduced from the SFGs study.[502]

Figure 21 Equity betas for US Utilities



Source: SFG (May 2012), Figure 3 on page 15.

1735. From the above two analyses, SFG argued that the approach the Authority has used to estimate equity beta is invalid.

The required return on unlevered equity cannot be lower than the required return on debt

1736. SFG submitted that, the unlevered equity beta (or asset beta) of 0.26 is equivalent to the equity beta of 0.65 adopted in the Authority's Draft Decision with the assumed gearing level of 60 per cent. Together with the assumed risk free rate of 3.67 per cent and the MRP of 6 per cent, the return to unlevered equity beta would be 5.23 per cent.[503]

[502] Strategic Finance Group, 2012, *Estimating Beta: Reply to Draft Decision*' Report prepared for Western Power, 29 May 2012' p. 14.

[503] Strategic Finance Group, 2012, *Estimating Beta: Reply to Draft Decision*' [R]eport prepared for Western Power, 29 May 2012' p. 16.

$$r_e = r_f + \beta_a \times MRP$$
$$= 3.67\% + 0.26 \times 6\% = 5.23\%$$

1737. SFG submitted that the debt holder in the benchmark firm requires a return of 5.82 per cent as concluded in the Authority's Draft Decision on Western Power's access arrangement, released in March 2012.

1738. SFG concluded that it is impossible for the required return on equity to be lower than the required return on debt in the same company because debts have a first-ranking claim over the cash flows of the firm (i.e. debts are entitled to be paid in full before any residual cash flows are paid to the equity holders).

The required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms

1739. Using the same argument put forward in response to the Authority's Issues Paper on Western Power's access arrangement in 2011, SFG submitted that the Authority's estimate of the required return on equity is lower than the return on equity from comparable firms.

1740. SFG submitted that a lower bound of a return on equity for a comparable firm is 10.95 per cent.[504] This return comprises three components of returns for equity holders: a dividend yield; a capital gain; and imputation tax credits.

1741. First, SFG submitted that the mean dividend yield for comparable firms is 7.34 per cent. This estimate was derived by the Authority as the current observable dividend yields of a sample of six comparable firms. SFG submitted that if an investor were to buy shares in the average comparable firm today, and if that firm was to simply maintain its current dividend with no increase in dividends at any time, that investor would receive a return of 7.34 per cent per annum on its investment every year in perpetuity. SFG argued that this figure of 7.34 per cent can be considered as a lower bound of the dividend yield.

1742. Second, SFG submitted that the Authority adopted an estimate of expected inflation of 2.55 per cent in its Draft Decision and that this 2.55 per cent can be considered as a lower bound for capital gains (i.e. there will be no real appreciation in stock prices at all).

1743. Third, SFG was of the view that the return from dividends and capital gains will need to be "grossed up" to reflect the value of imputation credits by multiplying by a factor of 1-t*(1-gamma)/(1-t) where *t* is the corporate tax rate. SFG's estimate of this component is 1.06 per cent.

Technical Issues from the Authority's Empirical Study

1744. Western Power submitted that it has a number of concerns with the statistical reliability of the Authority's approach to estimate equity beta. Its concerns can be summarised as follows.[505]

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504 Strategic Finance Group, 2012, *Estimating Beta: Reply to Draft Decision*' Report prepared for Western Power, 29 May 2012' p.19.

505 Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 158.

- The sample size is small. There is a large degree of variation between the Authority's calculated values and the AER's values for specific companies.
- The results do not pass standard statistical reliability tests.
- No adjustments were made to correct for the demonstrated bias in beta estimates.

1745. Western Power's second consultant on the issue, CEG, submitted that the Authority should err on the side of caution in its assessment of beta because of the following reasons.[506]

    - There is evidence that Australian betas have been depressed by the influence of the mining boom on the market index.
    - There is evidence that a 0.65 beta estimate is inconsistent with the risk premium allowed on the cost of debt.
    - There is empirical evidence that suggests that estimates of betas well below 1.0 should be adjusted upwards towards 1.0.
    - The aggressiveness of other aspects of the Authority's decision means that there is negative or no 'margin for error' left in the WACC when assessing beta.

Public Submissions to the Draft Decision

1746. Energy Networks Association was of the view that the Authority should take a conservative approach to determining a value of equity beta given the uncertainties of its empirical estimation.[507]

1747. Horizon Power was of the view that the level of systematic risk faced by Western Power and other Western Australian service providers is higher than national counterparts due to the nature of our resource-based economy and the relative immaturity of our regulatory system. Horizon is concerned that the Authority is imposing an overly low rate of return and that this is particularly relevant for equity beta which, at 0.65, is lower than the 0.8 used by other regulators.[508]

1748. Grid Australia stated that the use of an equity beta drawn from the midpoint of empirical estimates under-estimates the cost of capital for low beta assets and for "value" assets like regulated infrastructure.[509]

Final Decision

1749. The Authority considers each of the issues raised by Western Power and its consultants in turn below. Since there is an overlap among issues raised by SFG and CEG in relation to the technical aspects of the Authority's empirical study on the estimates of equity beta, the Authority will address these issues together.

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[506] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 159.

[507] Energy Networks Association, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 3.

[508] Horizon Power, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 3.

[509] Grid Australia, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 4.

SFG's practical issues

The approach on which the 0.65 is based produces implausible estimates over time and non-sensible outcomes in other industries and for the US energy sector

1750. In applying the approach adopted by Associate Professor Henry to estimate the equity beta, the Authority is aware that Henry carefully set out the rationale for the companies included in the sample to which the method is applied. The companies included in Henry's sample, which the Authority's study follows, represent the best comparator to the efficient benchmark network service provider.

1751. The Authority has been unable to replicate SFG's analysis and has concerns about the selection of companies used in the analysis. With regards to SFG's application of the Authority's method to the US energy sector, the Authority notes that there are only four US companies included in each of the data series presented by SFG.

1752. The Authority maintains its position from the Draft Decision that there may be problems with the way that SFG has tested the validity of Henry's applications to other Australian industries and to the US energy sector and is not a sufficient basis to conclude that Henry's method results in implausible or non-sensible outcomes.

The required return on unlevered equity cannot be lower than the required return on debt

1753. The Authority is of the view that there is a significant flaw in SFG's reasoning.

1754. First, the SFG approach of de-levering from the equity beta of 0.65 to derive the asset beta of 0.26 is problematic. The Authority is aware that SFG's de-levering process was also adopted by the AER in its WACC Review in 2009. However, the difference is that the AER *de*-levered and then *re*-levered whereas SFG only applied one direction of the process. While it is expected that any error that occurred due to the assumed debt beta of zero can be netted out in the AER's two-way process, this is not the case for SFG's one-way process.

1755. Second, while Henry (on behalf of the AER) and the Authority applied the de-levered/re-levered process to companies in the sample with similar characteristics in terms of gearing, SFG's process did not. The two-way process used by Henry and the Authority deals with gearing within the range of 40 per cent and 70 per cent to de-lever/re-lever to a benchmark gearing of 40 per cent. In contrast, SFG only applied a de-levering process to a benchmark gearing level of 60 per cent to the gearing level of zero.

1756. In conclusion, the Authority is of the view that SFG's de-levering process is inappropriate.

The required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms

1757. The Authority considers that, in forming its view that the required return on equity is materially lower than the return on equity that investors could reasonably expect to receive from comparable firms, SFG has incorrectly interpreted the Authority's decision and inconsistently adopted the input values of its estimate of the return on equity.

1758. First, as presented in the Draft Decision, the average dividend yield of 7.34 per cent is the actual figure for a sample of 6 companies in 2011. The Authority did not consider that this actual figure of dividend yield is appropriate to be used as a proxy for the future dividend yields by the 6 companies.

1759. Second, the Authority is of the view that, if SFG intended to estimate the return on equity for those companies in 2011, then the actual capital appreciation (or capital loss) for each company in the sample in 2011 should be calculated. The use of the capital appreciation of 2.55 per cent per annum, which is the expected inflation rate for the next 5 years from the Authority's Draft Decision, in the SFG application is misleading because the estimate of 2.55 per cent per annum is the forecasted inflation for the next five year, not for 2011 alone.

1760. In conclusion, the Authority is of the view that SFG's approach to estimating the cost of equity for the sample of six companies is problematic. The actual dividend yields for these six companies cannot, and should not, be considered as a proxy for the forecasted dividend yields for the next five years. In addition, combining an actual dividend yield in 2011 with an expected inflation rate for the next 5 years to estimate the return on equity is flawed. As such, SFG's application to estimate the forecast cost of equity for the above six companies is inappropriate for the purpose of the Final Decision on Western Power's proposed revisions to the access arrangement

Summary

1761. The Authority considers that three practical issues raised by Western Power and its consultants SFG in relation to the Authority's estimate of equity beta are flawed and do not assist in its determination of the cost of equity.

SFG & CEG: Econometric Issues Raised

1762. Each of the econometric issues raised by Western Power and its consultants, CEG and SFG, are addressed in turn below.

The sample size is small. There is a large degree of variation between the Authority's calculated values and the AER's values for specific companies

1763. The Authority considers that using weekly estimates in this analysis, as outlined by Henry in his study for the AER in 2008, is appropriate because it is a reasonable trade-off between the noisy nature of daily data and the small sample resulting from the use of monthly data.[510] In the Authority's Draft Decision, the Authority presented estimates of equity beta using monthly figures for comparison. The smallest number of weekly observations is 78 and the largest is 509. The pooled sample gives 3,149 observations that were used in the analysis. The Authority is of the view that this sample size is an adequate sample by most standards.

1764. The Authority also considers that the sample must be selected in an unbiased manner. The Authority is of the view that the sampling should be based on principles set out for a sample selection. The Authority is of the view that the sample the Authority had adopted in its estimate of equity beta is adequate to reflect the characteristics of the population of comparable companies. The

[510] Henry, O (2009) "Estimation Beta", Advice Submitted to the Australian Competition and Consumer Commission, p. 48.

Authority considers that adding companies from foreign markets that have an equity beta closer to one is a form of data mining and is inappropriate.

1765. The Authority considers that the differences between the estimates of equity beta by Henry, reported in the AER's WACC Review in 2009 and the Authority's Draft Decision are not surprising given the two studies used different data sets. The Authority notes that 80 per cent of the AER's data came from Datastream, whereas the Authority has sourced data from Bloomberg. The Authority considers that it is more appropriate to determine if the results were statistically different between the two studies. The Authority considers that the analysis supports the view that the overwhelming majority of the estimates of equity beta in the two studies were not statistically different. From its analysis, the Authority notes that only three out of the 90 estimates of equity beta were statistically different at the five per cent level of significance. The Authority considers that the findings from these tests indicate that the differences between the AER and the Authority's studies to estimate equity beta are not a statistical issue.

The results do not pass standard statistical reliability tests

1766. SFG describes the standard errors of the estimates as 'large' with no justification. The Authority is of the view that the well-accepted statistical practice to determine whether a standard error is large is to compare it to the size of the estimate itself. As a general rule, if the standard error of the estimate is greater than 50 per cent of the estimate itself,[511] the standard error is statistically 'large' in the sense that the error around the estimate is so large that it is likely to encompass the value of zero.

1767. The Authority considers that all standard errors of the beta estimates using weekly data are well below 50 per cent of the estimate itself. As such the estimates of beta are all statistically significantly different from zero at the five per cent level. In this sense, the standard errors could not be considered large. The Authority notes that the distributions of confidence intervals are not uniform. This means that the upper and lower bound values are statistically unlikely to represent the true value of beta.

1768. The Authority is of the view that the difference between Henry's and the Authority's estimates is small relative to the estimate of standard error, and that the errors around the Authority's estimates are therefore likely to encompass Henry's estimates without encompassing zero. This means that the Authority's estimates are statistically different from zero, but they are not statistically different from Henry's study for the AER.

1769. In relation to the low R-Square values, the Authority considers that the R-Square values measure the percentage of the total variation in the individual firm return explained by the CAPM regression, which is market returns. While there is reason to expect that some proportion of the variation of the firms' returns will be explained by market returns, there is no reason to expect that the greater proportion will be explained by market returns. The Authority is of the view that low R-Squares are common in asset regression and they do not indicate, or allow one to conclude that, results are statistically unreliable. The Authority considers that, traditionally, more emphasis is placed on the statistical significance of estimated parameters and that their signs from the estimates are consistent with *a priori* expectations. As discussed below, however, *a priori* expectations, in this case, are unclear.

511 Assuming t-distribution, sample size greater than 120 and a 5 per cent level of significance.

1770. The Authority is of the view that, in the estimate of equity beta, *a priori* expectations should be used as a cross-check. SFG was of the view that with a lower-than-average-for-the-market business risk and a higher-than-average-for-the-market financial risk, equity beta for network service providers should be equal to that of the market as a whole, which is equal to one. The Authority does not agree with this proposition. The Authority is of the view that there is no certainty about *a priori* expectations for equity beta for the network service providers. As a result, the benchmark beta should be arrived at through other means only, namely statistical analysis.

1771. With respect to concerns that the one-period estimate may not reflect market conditions that investors believe the future is most likely to hold, the Authority notes that its analysis was extended to include data up until April 2012. In the Authority's study, two sub-periods were considered: a pre- and a post- financial crisis with the resulting betas from each sub period tested to determine whether they were statistically different. These tests overwhelmingly concluded that betas pre-financial crisis were not statistically different to those post financial crisis (see Appendix 6).

1772. Other concerns are related to differences in point estimates of equity beta across firms. The Authority considers that these concerns can be addressed by drawing attention to the portfolio estimates of beta. These estimates are more likely to cancel out firm specific noise, which results in the wide distribution for individual firm betas. Such regressions result in more precise beta estimates that more accurately reflect systematic risk among firms in a comparable industry. Portfolio estimates based on the latest data tend to produce beta estimates much closer to 0.5 (see Appendix 7).

No adjustment is made to correct for the demonstrated bias in beta estimates

1773. The Authority acknowledges that thin trading can result in downward bias in beta estimates. The Authority has carried out thin trading tests in response to SFG's submission. The Authority notes that no strong evidence of thin trading was found in its recent analysis (see Appendix 8).

1774. The Authority considers that, in accordance with Henry's advice to the AER, more weight should be attributed to LAD estimates[512] in order to reduce the influence of outliers on the estimation of equity beta. The LAD estimates reduce the influence of outliers which increase the likelihood of a biased estimate. As previously discussed, portfolio estimates of beta are also more likely to cancel out firm specific noise in regressions resulting in more precise beta estimates that more accurately reflect systematic risk among firms in a comparable industry.

1775. Based on the Authority's own analysis, a range of 0.5 to 0.8 may be too high; many individual company estimates were considerably lower than 0.5. The weekly, LAD equally-weighted portfolio estimates tend to cluster around 0.5, which is well below the point estimate of 0.65. These estimates have reduced the influence of outliers and company specific effects. As such, these estimates of beta form an informative reference point. Accordingly, the Authority considers that the point estimate derived from this range is also high.

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[512] Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameter, pp. 267-268.

There is evidence that the Australian betas have been depressed by the influence of the mining boom on the market index

1776. If the structure of the economy, defined by market capitalisation, changes so that certain sectors become less sensitive to changes in market conditions, the Authority is of the view that this is simply a product of development over time. To deem such a change to be 'a temporary imbalance' and to remove the effect would be a speculative exercise and one that the Authority considers is inappropriate.

There is evidence that a 0.65 beta estimate is inconsistent with the risk premium allowed on the cost of debt

1777. The Authority notes that this line of argument was based on a view by Professor Grundy from the University of Melbourne that the equity premium, which is the product of the MRP and an equity beta, should be at least equal to 2.67 times the debt risk premium. Western Power and its consultant CEG argued that, in the Authority's Draft Decision released in March 2012, the equity premium of 3.9 per cent and the debt risk premium of 2.152 per cent do not meet this criterion. On this basis, they concluded that the Authority's estimate of the equity premium is too low and incorrect.

1778. The Authority notes that this issue was discussed at length in the Authority's Final Decision on DBNGP's access arrangement.[513] In that decision, the Authority relied on the work of Professor Davis and Associate Professor Handley who cautioned that the Modigliani-Miller theorem that provided the underpinning of Professor Grundy's proposition should not be used to imply any specific relationship between the cost of debt and the cost of equity. The Authority remains of the view that the assumption that Professor Grundy's work is not a valid basis for determining the relationship between equity premium and debt risk premium in circumstances where it cannot be assumed that equity and debt are priced in the same market.[514]

There is empirical evidence that suggests that estimates of betas well below 1.0 should be adjusted upwards towards 1.0

1779. The Authority considers that it is inappropriate to make any ad hoc adjustments to the estimates of equity beta. The Authority does not consider that beta estimates from the Authority's own analysis are well below one. If CEG's argument that beta should be revised upwards is to be sustained, then the equity beta for every company must be close to one and above one. The Authority is of the view that this is not the case and, as such, the equity beta of one, for the market as a whole, is sustainable.

1780. In conclusion, the Authority is of the view that there are no grounds for any ad hoc adjustments to any of the WACC parameters. The Authority is of the view that each and every WACC parameter should be estimated based on a robust and sensible method. The Authority is not convinced that a lower cost of debt, for example, should be compensated via a higher cost of equity and vice versa by making an ad hoc adjustment. Doing so would violate the integrity of the estimate of the WACC parameters and the entire WACC framework.

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513 Economic Regulation Authority, 2011, ***Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline,*** **October 2011.**

514 Economic Regulation Authority, 2011, ***Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline,*** **October 2011.**

Conclusion

1781. Based on the above considerations and its own empirical study in relation to the estimate of equity beta, the Authority is of the view that an estimate of the equity beta of 0.65 is appropriate.

Estimates of the Cost of Equity

1782. Western Power's response to the Draft Decision raised a number of issues in relation to estimating the cost of equity.

General Issues

Western Power's Submissions

1783. Western Power made four general observations about the estimate of the cost of equity, which are as follows.

- Western Power agrees with the Authority's decision to utilise the Sharpe-Lintner CAPM estimate the cost of equity. However, Western Power was of the view that the Authority did not assess the reasonableness of its cost of equity estimate nor properly consider whether the cost of equity estimate meets the requirements of the Access Code.
- Western Power is of the view that the cost of capital determined in the Authority's Draft Decision was substantially below that used by other Australian regulators. Western Power sought an explanation to why a business in Western Australia would raise capital at a cost far below that of equivalent businesses operating elsewhere in Australia.
- Western Power is of the view that the Authority has made a substantial departure from Australian regulatory precedent in respect of the determination of the risk free rate, the debt risk premium and the equity beta. Western Power argued that such drastic adjustments to the determination of the WACC are in themselves a breach of the requirement to promote economically efficient investment. Western Power considers investment cannot be promoted in the face of such regulatory uncertainty.
- Western Power submits that the Authority has considered each of the input WACC parameters in isolation. Western Power also argued that the Authority did not consider the interrelationships between parameters and adopted the output without analysing whether the cost of equity is consistent with the criteria in the Access Code.

Public Submissions

1784. Grid Australia submits that the low WACC estimate assumes a cost of equity too low to generate the return required to encourage investment.[515]

[515] Grid Australia, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, May 2012, p. 8.

Considerations of the Authority

1785. Each of Western Power's four general observations is responded to below.

1786. First, as discussed in paragraphs 1319 to 1326, the Authority is of the view that as long as the financial model is well accepted and the inputs to be used in the models are forward looking to reflect the prevailing conditions in the market for funds and a return on investment commensurate with the commercial risks involved in providing reference services, then the output from the model will be consistent with the objectives of the Access Code.

1787. Second, the Authority disagrees with Western Power's observation that the Authority's estimate of the cost of capital is substantially below regulatory precedent. Western Power and its consultant provided a summary indicating that the estimates of the cost of capital by the Authority are lower than the estimates by other Australian economic regulators, particularly the AER. The Authority considers that Western Power and its consultant ignored the requirements of the Access Code, which require the Authority to determine a rate of return that is an effective means of achieving the Access Code objective and the objectives in section 6.4. The relevant considerations to promote economically efficient investment in and operation and use of the network and to provide a return on investment commensurate with the commercial risks involved in providing reference services will differ from regulatory decision to decision.

1788. Third, Western Power considers that the Authority has significantly departed from Australian regulatory precedents for some WACC parameters, including the estimate of equity beta and the term of a nominal risk free rate. However, the Authority is of the view that these departures do not reflect the fact that the Authority has ignored the objectives of the Access Code in estimating the rate of return. Rather, the Authority has considered all available information and evidence before it, some of which may not have been available in the past, in reaching its decisions on the cost of capital parameters that best meet the Code objectives. In addition, any estimate of the cost of capital must be a forward looking estimate, which means it should reflect the prevailing conditions in the markets for funds at the time the decision is made. The Authority is of the view that the prevailing capital market conditions differ from those five or ten years ago.

1789. Fourth, the Authority is also of the view that each WACC parameter is required to be estimated in isolation to ensure the integrity of the estimate. The Authority considers that it is not appropriate to make ad hoc adjustments to one WACC parameter to "compensate" for another WACC parameter without due cause. For example, the Authority is not convinced that when the estimate of a nominal risk free rate of return is observed to be at a historically low level, an adjustment to the equity beta and/or the MRP can be applied to ensure that the return on equity derived from the Sharpe-Lintner CAPM remains unchanged. The Authority is of the view that making *ad hoc* adjustments to any WACC parameter to 'offset' an estimate of another WACC parameter is not appropriate and would give rise to idiosyncratic decisions, increasing regulatory uncertainty. The Authority considers that it is more appropriate to examine each WACC parameter to be satisfied that it meets the Code objective and the price control objectives of the Access Code in its own context to retain integrity in the estimates.

Final Decision

1790. The Authority is of the view that the estimate of the cost of capital should be forward looking and that it must reflect the prevailing conditions in the market for funds and a return on investment commensurate with the commercial risks involved in providing reference services. The Authority considers that the estimate of the cost of capital must reflect the Code objectives. However, the Authority is of the view that the departures of some WACC parameters in comparison with current practice do not mean that the objectives of the Access Code regarding the estimates of the rate of return are not fulfilled.

Alternative Methods to the Estimates of the Cost of Equity

Western Power's Submissions

1791. Ernst & Young (**E&Y**), Western Power's consultant on the estimates of the cost of equity, proposed the use of other alternative CAPM models, together with the Sharpe-Lintner CAPM, in estimating the return on equity for the purpose of this proposed Access Arrangement. E&Y concluded that using the CAPM to calculate the return component of the service provider's target revenue does not represent an effective means of promoting economically efficient investment, and does not give the service provider an opportunity to earn a return on investment commensurate with the commercial risks involved.[516]

1792. E&Y acknowledged that it has not estimated the parameters of the other asset pricing models. E&Y had simply used the estimates of the return on equity by others to support its argument that the use of the Sharpe-Lintner CAPM will underestimate the cost of equity for Western Power's Access Arrangement. E&Y's summary of its findings can be summarised in Table 175 below.

[516] Ernst & Young, 2012, *Advice on Capital Asset Pricing Model for response to ERA Draft Decision: Western Power (Electricity Networks Corporation)*, May 2012, p. 8.

Table 175 Risk Premium from Alternative Asset Pricing Models

Service Provider	Model	Premium above Risk-free rate (Per cent)
Western Power	CAPM	4.2
Jemena Gas Networks	Fama-French CAPM	6.5
WA Gas Networks	Black's CAPM	6.5
	Fama-French CAPM	6.7
	Zero-beta Fama-French CAPM	9.0
DBP	Black's CAPM	6.5
	Fama-French CAPM	6.0
	Zero-beta Fama-French CAPM	8.8

Source: Ernst & Young, 2012, *Advice on Capital Asset Pricing Model for response to ERA Draft Decision: Western Power (Electricity Networks Corporation)*, May 2012, page 18.

Public Submissions

1793. The Authority did not receive any public submissions on this issue.

The Authority's Assessments

1794. The Authority is of the view that the "capital asset pricing model" is only the generic term for any model that can be used to estimate the returns on capital including debt and equity. It is required that any model to be used for this purpose be well accepted. The Authority considers that the determination of an appropriate model to be adopted for this purpose is a critical step in its assessment of an appropriate rate of return.

1795. Over the last two years, the Authority has consistently rejected the use of "other" CAPM models to estimate the cost of equity. Other CAPM models, including Black CAPM; Fama-French CAPM; and Zero-beta Fama-French CAPM are not well accepted in Australia for the purpose of estimating the cost of equity for Australian regulated businesses.[517]

1796. The Authority is of the view that the Sharpe-Lintner CAPM is the most appropriate financial model, is well accepted, and is appropriately used by regulators to estimate the cost of equity for regulated businesses. The application of the alternative CAPM models has been considered in the Authority's decisions on the

[517] Economic Regulation Authority, 2011, ***Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline,* October 2011,** pp. 123 -158.

Western Australian Gas Networks and the Dampier to Bunbury Natural Gas Pipeline in 2011.[518] [519]

1797. The Authority does not consider that E&Y's report has introduced new and relevant material that would persuade the Authority to depart from its previous decisions on the selection of the Sharpe-Lintner CAPM model. The E&Y report reproduced the arguments which were put forward by regulated businesses such as WAGN and DBP and were considered in detail in the Authority's regulatory decisions in the past.

1798. The Authority is concerned about the method used by E&Y to derive estimates of the return on equity, based on the combination of different estimates of the return on equity for different regulated businesses at different points in time. For example, E&Y used estimates of the return on equity for Jemena Gas Networks from 2009; for WAGN from 2010; and for DBNGP from 2011. The prevailing conditions in the current market for funds cannot be directly compared to these historical periods.

1799. The Authority notes that Western Power has not referred to E&Y's advice on its revision of the return on equity in response to the Authority's Draft Decision. Western Power agreed with the Authority's Draft Decision that the Sharpe-Lintner CAPM should be used to estimate the return on equity for its revised Access Arrangement.[520]

Final Decision

1800. The Authority is of the view that, among various capital asset pricing models, the Sharpe-Lintner CAPM is the most appropriate well accepted model to derive the estimate of the cost of equity in this Final Decision for Western Power's Access Arrangement.

CEG's Estimates of the Cost of Equity

Western Power's Submissions

1801. Relying on CEG's advice, Western Power submitted that a range from 10.41 per cent to 14.59 per cent for the cost of equity meets the requirements of the Access Code. Western Power considered that the primary reason for the disparity between the Authority's and Western Power's estimate of the cost of equity is because CEG recognises that there is an inverse relationship between the market risk premium (**MRP**) and the risk free rate.[521]

1802. Based on CEG's advice on this issue, Western Power submitted that the cost of equity can be measured in one of three ways:

- First, directly estimating the cost of equity using the Dividend Growth Model.

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518 Economic Regulation Authority, 2011, ***Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline,* October 2011*,*** pp. 123 -158.

519 Economic Regulation Authority, 2010, ***Draft Decision on Proposed Revisions to the Access Arrangement for the Western Australian Gas Network, August 2010.***

520 Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 151.

521 Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 150.

- Second, directly estimating the prevailing market risk premium relative to the prevailing Commonwealth Government Securities (**CGS**) yields being used as the risk free rate.
- Third, estimating a 'normal' cost of equity for regulated businesses by estimating each of the CAPM parameters using suitable historical time periods.

1803. CEG's estimates of the cost of equity for Western Power's Access Arrangement using the above three methods are summarised in Table 176 below.

Table 176 Comparison of Cost of Equity Estimates: CEG versus the Authority

Item	Suggested Range (Per cent)
CEG Method 1	10.86 – 14.59
CEG Method 2	10.41
CEG Method 3	10.78
Cost of Equity Estimate [the CEG]	10.41 – 14.59
Cost of Equity Estimate [the Authority]	7.57

Source: *Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, Table 65, page 151*.

1804. Each of CEG's methods is outlined in turn below.

Method 1: CEG's estimates of the cost of equity using Dividend Growth Model

1805. CEG submitted that the first methodology, the DGM attempts to estimate the future path of dividends that investors' expect for a particular firm (or set of firms that have the same risks as are involved in providing reference services). CEG also submitted that having done this, the discount rate is then calculated by equating this dividend path with current market prices. This effectively involves estimating the risk free rate, beta and MRP collectively and this process delivers an estimate of the cost of equity for the reference services directly.[522]

1806. CEG considered that this first methodology is entirely forward looking; and that this methodology does not provide estimates of the individual CAPM parameters.[523]

1807. CEG acknowledged that the adoption of this methodology is only possible if there are listed equities with comparable risk to the reference services and there is some

[522] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, p. 55.

[523] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 56-7.

methodology for arriving at an estimate of the future dividends that investors expect that equity to pay. CEG submitted that the US regulators rely in part on a relatively deep pool of analyst forecasts for this purpose. However, CEG also admitted that the level of analyst coverage for individual regulated businesses, and certainly the pool of regulated businesses, is not as deep in Australia as in the US.

1808. CEG also acknowledged on another potential objection to this approach: that the estimates of the cost of equity are sensitive to the level of stock prices at the time that the estimates are made. The volatility in equity prices (relative to long run dividend forecasts) means that the DGM estimate of the cost of equity will also be volatile.

1809. However, CEG argued that all these weaknesses can reasonably be argued to be a ‘feature’ rather than a ‘bug’ to the extent that the volatility in equity prices is driven by volatility in prevailing conditions in equity markets. CEG was of the view that at least part of the volatility in equity prices is likely to be driven by illiquidity in the market for a particular equity. CEG argued that part of the volatility in DGM estimates may simply reflect movements driven by lopsided buy or sell side activity. CEG concluded that this weakness can potentially be addressed by using a longer average of equity prices such as a period covering over a month or several months.[524]

1810. CEG then presented its estimates of the cost of equity of between 10.86 per cent and 14.59 per cent, using the DGM. These estimates are based on analyst dividend forecasts and the average price of equities for six firms, being the six Australian utilities businesses, including APA Group, DUET Group, Envestra, Hastings Diversified Utilities Fund, SPAusNet and Spark Infrastructure sourced from Bloomberg on 24 February 2012 and 9 March 2012. The range for the cost of equity is based on a range for long term dividend growth from zero growth in real terms (2.5 per cent nominal) to growth in line with long term average GDP growth (6.6 per cent nominal).[525]

Method 2: CEG’s estimates of the cost of equity using the “prevailing” market conditions

1811. CEG submitted that, as with the first methodology, the second methodology relies on a DGM estimate of prevailing returns. However, the DGM is applied to the market as a whole (not only for comparable firms). CEG then estimated a prevailing market cost of equity at 11.96 per cent and MRP at 7.75 per cent, based on the AMP method using March 2012 dividend yields from the RBA, long run dividend growth of 6.6 per cent nominal and an assumption that each dollar of dividend delivered to investors comes with 11.125 cents value of franking credits.[526] CEG then assumed an equity beta of 0.8 and risk free rate of 4.21 per cent over

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[524] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 56-7.

[525] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, p. 57.

[526] Assuming payout ratio of 0.75; theta of 0.35 and corporate tax rate of 30%, this means that on average each dollar of dividends had attached to it imputation credits valued by investors at 11.125 cents (being 0.75*0.35*0.3/(1-0.3)).

March 2012, giving a cost of equity for the reference services of 10.41 per cent using the Sharpe-Lintner CAPM.[527]

1812. In summary, the central idea of this second approach is an application of the AMP methodology to estimate prevailing MRP of 7.75 per cent and then application of beta of 0.80, along with prevailing risk-free rate of 4.21 per cent over March 2012, to estimate the cost of equity of 10.41 per cent for the reference services.[528]

1813. CEG also submitted a different method adopted by Bloomberg, using analysts' forecasts of near term dividend growth and its own model of transition and steady state growth, which estimates the prevailing market cost of equity at 12.7 per cent and MRP of 8.6 per cent. As such, the cost of equity of 11.09 per cent can be calculated using the MRP of 8.6 per cent; an equity beta of 0.8; and risk free rate of 4.21 per cent over March 2012 for the averaging period of the 20 days to 30 March 2012.[529]

Method 3: CEG's estimates of the cost of equity using the "normal" market conditions

1814. The third methodology relies on historical average data. CEG argued that it is possible to estimate the historical average risk free rate that can be used in conjunction with a historical average MRP estimate (such as the ERA's 6 per cent estimate). CEG adopted the historical average yield on inflation indexed CGS. Based on a time series from July 1993 since the RBA's inflation targeting policy, the average yield on indexed CGS was 3.40 per cent. CEG then argued that. if expected inflation going forward is 2.50 per cent, then a 5.99 per cent nominal CGS yield is required to deliver the same 3.40 per cent real yield using Fisher's equation. As a result, together with an equity beta of 0.8 and an MRP of 6.0 per cent, the real cost of equity is 8.20 per cent, which is equivalent to a nominal cost of equity of 10.78 per cent.[530]

1815. In conclusion, based on evidence presented by the CEG in relation to alternative approaches to estimating the cost of equity, Western Power proposed a revised cost of equity is 10.41 per cent. This estimate of the cost of equity was based on a MRP of 7.75 per cent, a risk free rate of 4.21 per cent, and an equity beta of 0.80. Western Power also noted that the revised cost of equity of 10.41 per cent is the lower bound of the cost of equity range recommended by CEG and is supported by cross-checks against alternative asset pricing models as recommended by E&Y.[531]

The Authority's Assessments

1816. Each of the above three proposed approaches to be adopted in the estimates of the cost of equity for the purpose of Western Power's revised Access Arrangement are

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[527] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 58-9.

[528] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 58-9.

[529] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 58-9.

[530] Competition Economists Group, 2012, *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, pp. 59-60.

[531] Western Power, 2012, Amended Access Arrangement Information for the Western Power Network: Response to the Economic Regulation Authority's 29 March 2012 Draft Decision, p. 151.

discussed in turn below. Since CEG's methods 1 and 2 are involved with the estimates of the cost of equity using the DGM, they are addressed jointly.

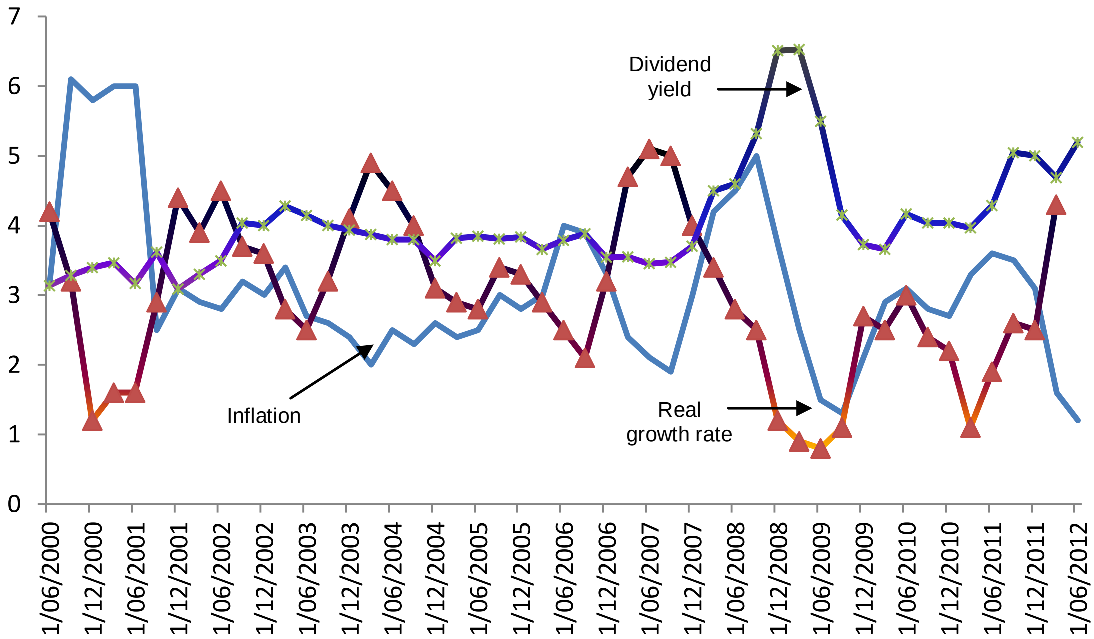
CEG's Methods 1 and 2

1817. The disadvantages of using the DGM, or any similar model or approach that involves many different assumptions about the inputs into the model to estimate the cost of equity, was discussed at length by the Authority in its previous regulatory decision on the revised access arrangement for WAGN Mid-West and South-West Distribution Systems. The Authority remains of the view that DGM and similar models or approaches are not suitable for the purpose of estimating the cost of equity for Australian regulated businesses as they are based on economic forecasts that are highly subjective and vary significantly across equity analysts and over time.[532]

1818. The Authority is of the view that as the DGM involves at least three forecasts (dividend yield, inflation and GDP growth), any error in these individual estimates compounds for the overall estimate of MRP.

1819. As an updated analysis, the Authority has recently conducted its own analysis of the behaviour of the three components, being (i) dividend yield; (ii) real rate of growth; and (iii) inflation, which are the key components used in any dividend growth model, for the period from June 2000 to June 2012. The Authority retains its view that each of these components is itself an estimate and as a result is subject to a high degree of uncertainty.

Figure 22 Quarterly Dividend Yield, Inflation and GDP Growth, June 2000 – June 2012, Per cent



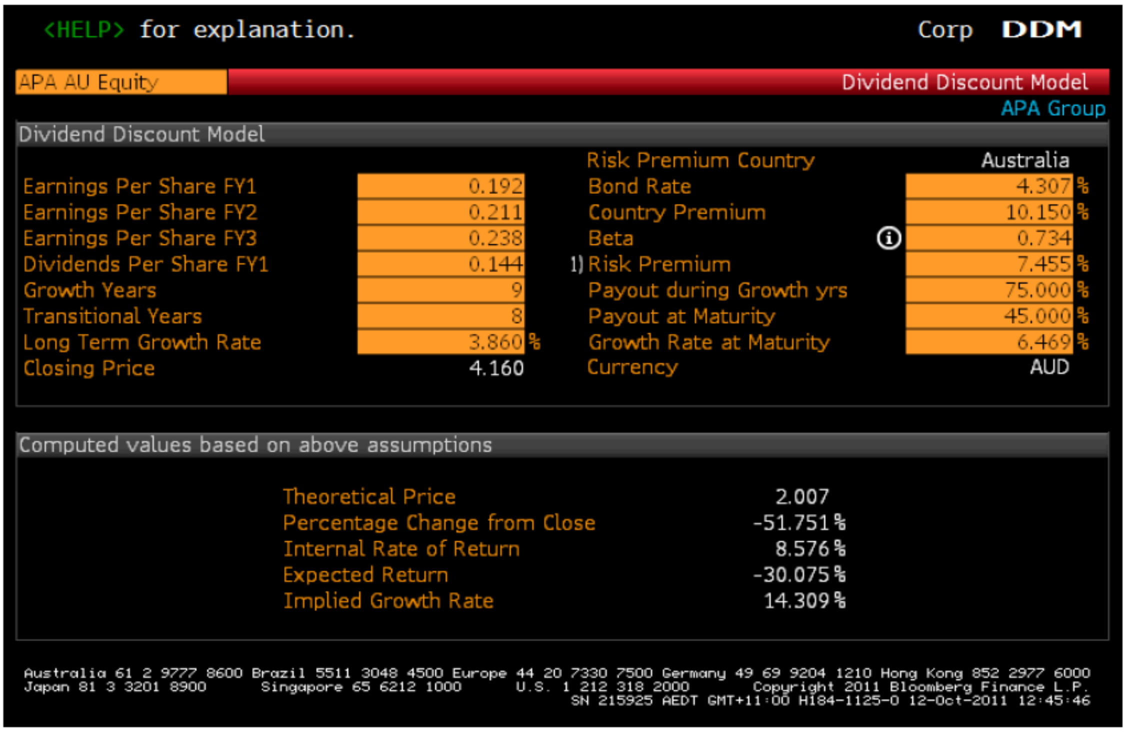
Source: Bloomberg

532 Economic Regulation Authority, 2010, *Draft Decision on WA Gas Networks Revision Proposal for the Access Arrangement for the Mid-West and South-West Gas Distribution Systems,* August 2010, pp 100-2.

1820. For example, as presented by CEG, the estimate of the internal rate of return is the key input in Bloomberg's Discount Model. The Authority has compared the model produced in the CEG report in May 2012 with the Bloomberg model in July 2012. The Authority notes that the internal rate of return reduced from 8.576 per cent in May 2012 to 7.285 per cent in July 2012, a difference of 15 per cent in just two months, as presented in Figure 23 and Figure 24 below. The Authority considers that it is difficult to explain the magnitude of this difference. The Authority is of the view that a difference of the same magnitude may affect other companies in the same sample adopted by CEG.

1821. The Authority is of the view that such a significant change in the estimate of the internal rate of return will result in a significant difference in the overall estimate of the cost of equity using Bloomberg's method. Bloomberg also notes that the internal rate of return is calculated based on more than 10 different assumptions as illustrated in the screenshot from Bloomberg below.

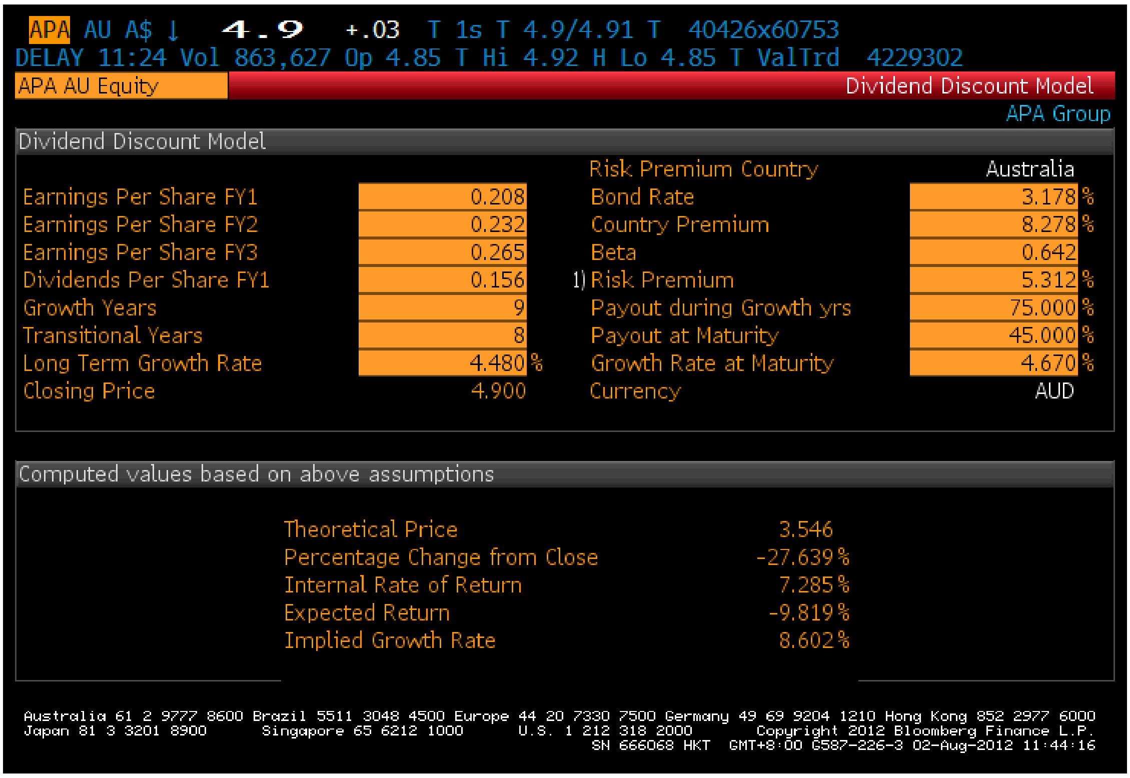
Figure 23 Bloomberg's Discount Model: APA AU Equity, May 2012



Source: Bloomberg

Source: CEG, 2012. Internal Consistency of Risk free rate and MRP in the CAPM May 2012, Figure 18, page 66.

Figure 24 Dividend Discount Model: APA AU Equity, July 2012



Source: Bloomberg.

1822. In summary, the Authority is not in a position to question the validity of the models applied by Bloomberg and the AMP, which were based on a set of unknown assumptions. However, the Authority expresses the same concern with the inputs (i.e. assumptions) to be used in the models. Outcomes derived from these two models are based on a very short timeframe. Unless these models are tested using a long data series and a sensible outcome is presented, the Authority is of the view that these two models are not suitable for the purpose of estimating the cost of equity for Western Power's revised access arrangement.

CEG's Method 3

1823. The Authority does not agree with CEG's argument that the "normal" risk free rate should be accompanied by the "normal" MRP using historical data. The Authority does not consider it is inconsistent to:

- estimate the forward-looking MRP using a long term historical data on equity risk premium; and
- estimate the nominal risk-free rate using the averaging period of 20 trading days in the month prior to when the decision is to be made.

1824. The MRP is unobservable. As such, a proxy needs to be developed to estimate the forward-looking MRP. Given all methods involved with forecasting are subject to a high level of uncertainty and fluctuation, using historical data for a long period of time is a viable option. Using historical data on equity risk premium for a long period of time to estimate the MRP assumes that investors expect what actually occurred in the past is the best possible proxy for the future. It appears that CEG agrees with this assumption.[533]

1825. In addition, based on its own analysis, the Authority is of the view that the averaging period of 20 trading days to estimate the nominal risk free rate of return is the best proxy for future patterns of the risk free rate for the next 5 years. This issue is addressed in a separate section, titled "the Nominal Risk Free Rate of Return", in Appendix 9.

Final Decision

1826. The Authority does not consider that Western Power and its consultant, CEG, have put forward any convincing evidence for a departure from the standard regulatory practice in Australia of using the Sharp-Lintner CAPM to estimate return on equity. The Sharp-Lintner CAPM requires the estimates of the risk free rate, the MRP and equity beta.

1827. On the grounds of the above analyses, the Authority considers that it is appropriate to estimate the return on equity using the MRP (which is estimated based on historical data on equity risk premium) and equity beta (which is estimated using Henry's approach). The Authority is of the view that there is no inconsistency regarding the estimate of the MRP and the adoption of a 20-trading day period to derive the nominal risk free rate.

[533] Competition Economists Group, 2012. *Internal Consistency of Risk free rate and MRP in the CAPM,* Prepared for Western Power, footnote 65 on p. 59.

Effective Tax Rate

Western Power's Initial Proposal

1828. Western Power proposed to adopt the current corporate tax rate of 30 per cent to calculate a pre-tax WACC.[534] The corporate tax rate under the current Access Arrangement is also 30 per cent.

Considerations of the Authority

1829. Consistent with Australian taxation law, the Authority has applied the current corporate tax rate of 30 per cent to calculate the tax liabilities within the post-tax building block that contributes to the determination of the revenue requirement.

1830. The resulting effective tax rate is an explicit endogenous outcome of the post-tax building block (refer paragraph 1306).

Final Decision

1831. The Authority approves the use of a corporate tax rate of 30 per cent.

Value of Imputation Credits (Gamma)

Western Power's Initial Proposal

1832. Western Power proposed an estimate of gamma of 0.25. This proposal was based on a recent decision by the Australian Competition Tribunal (**ACT**) with regard to the estimate of gamma.

Considerations of the Authority

1833. A full imputation tax system for companies has been adopted in Australia since 1 July 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below), many other countries have a partial imputation system, where only partial credit is given for the company tax.

1834. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

1835. A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation credits and therefore require a higher pre-tax income in order to justify investment.

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[534] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 260.

1836. The Authority is aware that the value of gamma was considered by the Australian Competition Tribunal in a recent application by Energex Limited[535] and this decision on the value of gamma has been taken into consideration, in relation to the estimates of the payout ratio and the value of theta, for the Authority's Final Decision on the proposed Access Arrangement.

Payout Ratio (F)

1837. The Authority considers that an estimate of the payout ratio of 70 per cent is appropriate based on the empirical evidence currently available. This estimate is consistent with the Tribunal's decision with regard to the value of the payout ratio.[536] The Authority is of the view that existing evidence still supports the use of a range of 70 per cent and 100 per cent for payout ratio. The lower bound of 70 per cent is from empirical evidence and the upper bound is from the view that imputation credits do have a value. However, in the absence of any new evidence and in the interest of regulatory certainty so as to not distort future investment decisions, the Authority has no basis to depart from the findings of the Tribunal in respect of gamma.

1838. In conclusion, the Authority's decision is to adopt the payout ratio of 70 per cent for the purpose of Western Power's proposed revised Access Arrangement.

Theta (θ)

1839. The dividend drop-off study is the only approach used by the Tribunal to determine the value of theta. The Tribunal considered that redemption rate studies should only be used as a check on the reasonableness of the market value of imputation credits as estimated from dividend drop-off studies. On this basis, the Authority may consider further evidence on the estimate of theta using redemption rate studies in the future when this sort of study has been refined on economically justifiable grounds (such as a consideration of any time value loss between when imputation credits are distributed and when they are redeemed, which is currently not taken into account in redemption rate studies).

1840. The Authority maintains its position in its previous regulatory decision[537] that dividend drop-off studies are affected by estimation issues, including multicollinearity and heteroscedasticity. As such, estimates of theta using dividend drop-off studies are inherently imprecise. As a result, the Authority is of the view that a range of evidence should be considered where available.

1841. For the same reason as discussed in paragraph 1837 with regard to the estimate of the payout ratio, the Authority considers that, in the absence of any reliable new evidence and in the interest of regulatory certainty, it should apply a value of theta which is consistent with the Tribunal's decision. Applying SFG's 2011 dividend

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535 Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

536 Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

537 For example, see Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, p. 140.

drop off study, the Authority has determined a value of theta of 0.35 for the purpose of this Final Decision.[538]

Gamma (γ)

1842. Based on an estimate of the payout ratio of imputation credits of 70 per cent, together with an estimate of theta of 0.35, the Authority concludes that a reasonable value of gamma for Western Power's proposed Access Arrangement is 0.25 (or 25 per cent). The estimate of gamma of 0.25 is consistent with the Tribunal's recent decision on gamma in *Energex Limited*.[539]

Final Decision

1843. The Authority approves Western Power's proposal in relation to gamma of 0.25.

[538] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 38.

[539] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 42.

SERVICE STANDARD BENCHMARKS

1844. Western Power has proposed significant changes to Service Standards Benchmarks (**SSBs**) to apply for the third access arrangement period. SSBs allow users to assess the value of reference services at the reference tariff, and also are an important point of reference for the application of the Service Standard Adjustment Mechanism (**SSAM**). The SSAM provides incentives for Western Power to improve service standard performance over time, and provides for penalties for under-performance.

Access Code Requirements

1845. A service standard is defined in section 1.3 of the Access Code as either or both of the technical standard, and reliability, of delivered electricity. SSBs are the benchmarks for service standards for a reference service in an access arrangement. A service provider is required to provide reference services at a standard at least equivalent to these benchmarks.

1846. Section 5.1(c) of the Access Code requires that an access arrangement include SSBs for each reference service.

1847. The requirements for SSBs are set out in section 5.6 of the Access Code. A service standard benchmark must be reasonable and must be sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

Current Access Arrangement

1848. The current access arrangement specifies SSBs for:

- transmission services;
- distribution services; and
- streetlighting.

1849. The method for deriving the SSBs involves taking the average performance on each measure for a sequence of historic monthly data.

Transmission network service standard benchmarks

1850. The transmission network service standard measures cover transmission circuits operating at 66 kV or above. Terminal station interconnecting power transformers are included, but zone substation supply transformers that form the interface between the transmission and distribution systems are not.

1851. In respect of the reference services A11 and B2 available to users directly connected to the transmission network, the SSBs are expressed in terms of Circuit

Availability; System Minutes Interrupted; Loss of Supply Events; and Average Outage Duration – as defined below:[540]

- Circuit availability refers to the availability of the transmission network. The circuit availability benchmark measures network availability and is defined as the percentage of total possible hours available (that is, the actual circuit hours available for transmission circuits divided by the total possible defined circuit hours available), where a higher percentage corresponds to a higher service standard;
- System Minutes Interrupted (for both meshed and radial transmission networks) records the period of network outages measured in minutes and is recorded for transmission meshed and radial networks separately. A meshed network refers to an electricity network where there is more than one path between network nodes. Specifically, the system minutes interrupted benchmark is the summation of megawatt minutes of unserved energy at substations that are connected to the meshed/radial transmission network divided by the system peak megawatts. The indicator provides a measure of the minutes of peak demand not supplied as a consequence of faults on the transmission network. A lower value of system minutes interrupted corresponds to a higher service standard;
- Loss of Supply Event Frequency records the frequency of events where the loss of supply exceeds two benchmarks (0.1 system minutes and 1.0 system minutes), where lower values on the two measures indicate a higher standard of service; and
- Average Outage Duration records the sum of all minutes of unplanned outage divided by the total number of unplanned outage events, where a lower value indicates a higher standard of service.

1852. A range of excluded services are specified for the SSBs for transmission, including force majeure events and interruptions triggered by a third party. Planned outages are included for the Circuit Availability and System Minutes Interrupted measures, but not for the Loss of Supply Event Frequency or Average Outage Duration measures.

1853. As noted by GBA in its report prior to the Draft Decision:[541]

> Unlike SAIDI and SAIFI, planned outages are included in the [Circuit Availability] measure, although the duration of extended planned outages is capped at 14 days for measurement purposes. Hence the measure captures not only the reliability of the transmission assets, but also how effectively Western Power manages asset maintenance.

Distribution network service standard benchmarks

1854. SSBs for the distribution system reference services A1 to A10, B1 and C1 are expressed in terms of two metrics – System Average Interruption Duration

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540 For detailed definitions, see Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 7 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

541 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 26.

Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**). The SAIDI and SAIFI benchmarks are used as reliability measures, with a lower value corresponding to a higher service level:

- SAIDI is a measure of the total number of minutes interruption a customer experiences per annum on average; and
- SAIFI is a measure of the total number of interruptions a customer experiences per annum on average.

1855. Exclusions to SAIDI and SAIFI comprise:

- major event days where the IEEE1366-2003 definition is exceeded;[542]
- outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation);
- planned outages; and
- force majeure events.

Streetlighting service standard benchmarks

1856. In respect of reference service A9 (Streetlighting Exit Service), where Western Power is responsible for the repair of faulty streetlights, the SSBs relate to the repair times for reported faults.

Proposed revisions

1857. In the proposed revisions to the access arrangement (September 2011), Western Power proposed three significant changes to the SSBs for the third access arrangement period, to:

- revise the level at which the SSBs are set, to quantify a *minimum level of service*, rather than the previous expected level of service;
- reduce the number of SSBs and change the definitions of the measures; and
- widen exclusions to include any that are accepted by the Authority in its service standard performance report.

1858. Western Power provided supporting information for the proposed revisions to service standard benchmarks in the access arrangement information.[543]

542 In essence, the 2.5 Beta Method under this definition excludes days which exceed all but the most extreme of observed values, based on historic data. Specifically, a major event day under the 2.5 Beta Method is one in which the daily total system SAIDI value exceeds a threshold value, T_{MED}, where $T_{MED} = e^{(\alpha = 2.5\beta)}$. (Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, 17 December, p .109.

543 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, Appendix Y. Additional information relevant to the consideration of Western Power’s proposed service standard benchmarks is contained in Western Power 2011, *Service Standard Performance Report Year Ending 30 June 2011*,

Minimum levels of service

1859. In its September 2011 proposed revisions, Western Power sought to move away from the target SSBs of the current access arrangement to 'minimum service' SSBs.[544]

1860. As a result, the SSBs proposed by Western Power for the third access arrangement generally are based on the 97.5 per cent probability of exceedence (**PoE**) level, whereas the SSBs for the current access arrangement are based on the expected (average) 50 per cent PoE level of performance derived from historic performance data.[545] That said, Western Power has proposed to retain the expected (50 per cent PoE) value of performance for the SSAM mechanism Service Standard Targets (**SSTs**).

Transmission network service standard benchmarks

1861. In its September 2011 proposed revisions, Western Power proposed for the third access arrangement period to discontinue the majority of the existing service standard measures for transmission, apart from the Circuit Availability measure. The current and proposed transmission SSBs, as well as the proposed Service Standard Adjustment Mechanism (**SSAM**) Service Standard Targets (**SST**s) are set out in Table 177.

1862. In addition, a new service standard measure was proposed by Western Power for transmission services in the third access arrangement period – the Individual Customer Service Measure. This was defined as the percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:

- an account manager for the full 12 month period;
- an annually reviewed customer service management plan; and
- an invitation to participate in an annual satisfaction survey.

1863. Western Power's proposed Customer Service measure SSB for transmission reference services is set out in Table 178. Western Power proposed to set the transmission system individual customer service measure SSB at 100 per cent.

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www.erawa.com.au, September and Economic Regulation Authority 2011, *2009-10 Annual Performance Report: Electricity Distributors,* www.erawa.com.au, March.

544 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 91.

545 The 97.5 per cent PoE applies where higher numbers signify better performance. Where lower numbers signify better performance, then the 2.5 per cent PoE applies.

Table 177 Transmission system SSBs and SSTs for reference services A11 and B2 for the current access arrangement and proposed for the third access arrangement period (in September 2011)

	AA2 year ending June 2010 SSB and SSAM SST	AA2 year ending June 2011 SSB and SSAM SST	AA2 year ending June 2012 SSB and SSAM SST	Proposed AA3 financial year 2013 – 2017 SSB (min. stand.)	Proposed AA3 financial year 2013 – 2017 SSAM SST
Circuit Availability (% of total time)	98.0	98.0	98.0	97.3	97.8
System Minutes Interrupted (meshed network) (minutes)	9.3	9.3	9.3	np	np
System Minutes Interrupted (radial network) (Minutes)	1.4	1.4	1.4	np	np
Loss of Supply Event Frequency (Number of events > 0.1 System Minutes)	25	25	25	np	np
Loss of Supply Event Frequency (Number of events > 1 System Minutes)	2	2	2	np	np
Average Outage Duration (Minutes)	764	764	764	np	np

Note: np = 'not proposed' by Western Power as a measure for AA3; **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA2** = second access arrangement; **AA3** = third access arrangement.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

Table 178 Transmission system individual customer service measure SSBs – proposed for the third access arrangement period (in September 2011)

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year SSB
Individual customer service measure	-	-	-	100%

Note: **AA3** = third access arrangement

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, September, p. 16.

Distribution network service standard benchmarks

1864. In its proposed revisions to the access arrangement (September 2011), Western Power proposed that the definition for the distribution network SAIDI and SAIFI measures be widened for the third access arrangement period to include distribution network average interruption duration and frequency that are related to interruptions *arising in the transmission network*. These were proposed to be defined as follows (change italicised):[546]

- SAIDI is an annual measure of the sum of the duration of each sustained (greater that 1 minute customer interruption (in minutes) attributable to *either or both of the transmission system and distribution system* (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period;
- SAIFI is an annual measure of the total number of sustained (greater than 1 minute) customer interruptions (number) attributable to *either or both of the transmission system and distribution system* (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.

1865. The wording of the exclusions for both measures also was proposed to be widened to exclude the events for the transmission network that also apply to the distribution network for these measures. In particular, it was proposed that exclusions cover:[547]

- For an interruption on either or both of the *transmission system* and *distribution system*, a day on which the major event day threshold, determined in accordance with IEEE1366-2003 definitions applying the "2.5 beta method", is exceeded.[548]

546 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 10.

547 Ibid.

548 The Authority notes that IEEE 1366-2003 standard uses the '2.5 Beta Method' to identify major event days which are excluded from the reliability standards and individual feeder standards. A major event day under the Beta Method is one in which the daily total system SAIDI value exceeds a threshold value, T_{MED}, where $T_{MED} = e^{(\alpha = 2.5\beta)}$ and β is the standard deviation of the historical data (Institute of Electrical and Electronics Engineers, *1366-2003: IEEE Guide for Electric Power Distribution Reliability Indices*).

- Interruptions on either or both of the *transmission system* and *distribution system* shown to be caused by a fault or other event on a third party system (for instance, without limitation, interruptions caused by an intertrip signal, generator unavailability or a consumer installation).

- Planned interruptions on either or both of the *transmission system* and *distribution system* caused by scheduled *works.*

- *Force majeure* events affecting either or both of the *transmission system* and *distribution system*.

1866. The SSBs expressed in terms of SAIDI for the reference services A1 to A10, B1 and C1 for each year of the current access arrangement period are set out in Table 179.

Table 179 Distribution system SAIDI SSBs and SSAM SSTs (minutes) – current access arrangement and proposed for the third access arrangement period (in September 2011)

	SWIN total	CBD	Urban	Rural short	Rural long
Existing arrangement					
AA2 year ending June 2010 SSB and SSAM SST	230	38	165	259	612
AA2 year ending June 2011 SSB and SSAM SST	224	38	162	253	588
AA2 year ending June 2012 SSB and SSAM SST	213	38	153	244	556
Proposed arrangement					
AA3 financial year proposed (minimum standard) SSB	-	56	200	360	720
AA3 financial year proposed SSAM SST	-	28	163	254	616

Note: The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR) ; **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA2** = second access arrangement; **AA3** = third access arrangement.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 77 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13 and p. 42.

1867. The SSBs expressed in terms of SAIFI for the reference services A1 to A10, B1 and C1 for each year of the current access arrangement period are set out in Table 180.

1868. Western Power's *proposed* SSBs expressed in terms of SAIDI and SAIFI for the third access arrangement period are shown in the last rows of Table 179 and Table 180. In both cases, Western Power proposed to discontinue the 'SWIN total' metric. The remaining SSB metrics had significantly higher allowances – increasing by around a third in some cases compared to those applying in the current access arrangement. The proposed SSAM service standard targets (**SSTs**) for the third access arrangement were also less onerous than the current access arrangement SSBs for all but the CBD. These changes reflected, among other things, the move to minimum standards for the SSBs and the inclusion of transmission interruptions in the measures.

1869. An additional two service standards for the distribution system were proposed for the third access arrangement period that are not included in the current access arrangement:

- Call Centre Performance percentage – measured as the number of fault calls responded to in 30 seconds divided by the total number of fault calls per year; and
- Circuit Availability – this is transmission Circuit Availability, but now included as a distribution performance measure as well.

Table 180 Distribution system SAIFI SSBs and SSAM SSTs (events) – current access arrangement and proposed for the third access arrangement period (in September 2011)

	SWIN total	CBD	Urban	Rural short	Rural long
Existing arrangement					
AA2 year ending June 2010 SSB and SSAM SST	2.5	0.24	1.92	3.12	5.00
AA2 year ending June 2011 SSB and SSAM SST	2.46	0.24	1.89	3.06	4.85
AA2 year ending June 2012 SSB and SSAM SST	2.41	0.24	1.83	2.98	4.80
Proposed arrangement					
AA3 financial year proposed (minimum standard) SSB	-	0.40	2.30	4.20	5.70
AA3 financial year proposed SSAM SSTs	-	0.22	1.90	2.91	4.77

Note: The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR) ; **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA2** = second access arrangement; **AA3** = third access arrangement.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 7 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

1870. Western Power's proposed Call Centre Performance percentage for each year of the third access arrangement period for the reference services A1 to A10, B1 and C1 to C4 is shown in Table 181.

Table 181 Distribution system Call Centre Performance SSB and SSTs – proposed for the third access arrangement period (in September 2011)

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year 2013 – 2017 SSB	Proposed AA3 financial year 2013 – 2017 SSAM SST
Call centre performance (percentage of calls responded to in 30 seconds)	-	-	-	75%	88%

Note: **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

1871. Western Power's proposed Circuit Availability for distribution reference services is shown in Table 182. As noted, this is the identical measure to that proposed for transmission networks.

Table 182 Distribution system SSB and SST for Circuit Availability – proposed for the third access arrangement period (in September 2011)

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year 2013 – 2017 SSB	Proposed AA3 financial year 2013 – 2017 SSAM SST
Circuit Availability (% of total time)	-	-	-	97.3	97.8

Note: **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

Streetlighting service standard benchmarks

1872. The service standard measure in respect of reference service A9 (Streetlighting Exit Service) – where Western Power is responsible for the repair of faulty streetlights – was not expected to change. The only proposed change by Western Power was that major regional towns be included in the Metropolitan area.

1873. The relevant SSBs applied in relation to repair times for reported faults are set out in Table 183. The benchmarks proposed for the next access arrangement period are the same as for the current period.

Table 183 Streetlighting SSBs – AA2 and proposed for the third access arrangement period (in September 2011)

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	AA3 proposed financial year
Metropolitan area	5 days	5 days	5 days	5 days
Major regional towns	5 days	5 days	5 days	5 days
Remote and rural towns	9 days	9 days	9 days	9 days

Note ; **AA2** = second access arrangement; **AA3** = third access arrangement.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 11.

Exclusions

1874. Western Power proposed a new clause 4.5.2 in the proposed revisions for the third access arrangement period which relates to exclusions. This clause stated that exclusions are usually first considered when the Authority publishes its service standard performance report under section 11.2 of the Code, and that any 'exclusion accepted by the Authority in such a report will be an exclusion for the purposes of this access arrangement and the Code'.[549]

Submissions

1875. In addition to Western Power's proposed revisions to its access arrangement (September 2011), service standard benchmarks are addressed in submissions received during the first round of consultation. These submissions were addressed in the Draft Decision.

1876. A number of submissions on the Authority's Draft Decision (second round of consultation), other than from Western Power, referred to service standards. The relevant points are included in the sections below.

Considerations of the Authority

1877. The Authority has given separate consideration to the basis for setting SSBs, the particular service standards for which SSBs are established and the proposed SSBs, and to exclusions. These are set out in what follows. The SSTs for the SSAM are considered in paragraphs 2120 to 2248.

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549 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 17.

Setting benchmarks as minimum service standards

1878. Western Power stated in its access arrangement information that 'if the service standard benchmarks are not set at a minimum service level, additional expenditure would be required to improve the certainty the SSBs can be met'.[550]

1879. The minimum standards approach was proposed by Western Power to address two concerns. The first is to ensure that it does not breach section 11.1 of the Code, specifically its obligations set out in its transmission and distribution licences.[551] Second, Western Power noted that not meeting the SSTs results in any gain sharing mechanism surplus being foregone in a year when the SSBs are not reached.

1880. Western Power noted that Clause 6.26 of the Access Code implies that gain sharing above-benchmark surplus can only be realised if all SSBs are met in a particular year:

> 6.26 An above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period by failing to comply with section 11.1. {Note: Section 11.1 requires a service provider to maintain a service standard at least equivalent to the service standard benchmarks set out in the access arrangement or access contract.}

1881. Clause 5.14C in the current access arrangement, and now clause 7.4.3 in the third access arrangement period, mirrors clause 6.26 of the Access Code.[552] Western Power stated that as a result it lost gain sharing benefits in the current access arrangement period due to not achieving all its SSBs in 2009/10 and 2010/11.[553]

1882. The Authority acknowledged in its Draft Decision that Clause 6.26 and Section 11.1 of the Code may be interpreted to create a link between the SSBs and the gain sharing mechanism, to prevent gain sharing rewards from occurring at the expense of achievement of the SSBs.

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550 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92.

551 Clause 11.1 of the Code states: 'A service provider must provide reference services at a service standard at least equivalent to the service provider's service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.'

552 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, September, p. 39. Clause 7.4.3 of the AA3 states 'In any year in which an above-benchmark surplus is calculated to be a positive value the above-benchmark surplus does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks for that year as set out in section 4 of this access arrangement'.

553 Western Power states that 17 out of 19 SSBs were achieved in 2009-10 and 2010-11, and that as a result, no gain sharing incentives were achieved in these years. The standards not achieved in 2009-10 related to SAIDI on long rural lines and Loss of Supply Event Frequency (number of events > 0.1 system minutes). The standards not achieved in 2010-11 related to Circuit Availability and System Minutes Interrupted (radial networks).

1883. The Authority therefore accepted that there is a potential to create a large additional penalty should a SSB not be achieved – that may not be proportionate to the resulting cost to consumers of the under-performance.

1884. Given this potential for a penalty 'discontinuity', the Authority considered that there may be unintended consequences from these provisions in the Access Code. On this basis, the Authority accepted in the Draft Decision that the proposed minimum SSB approach provides a means to remove the 'discontinuity' in the SSAM.

1885. This move was supported by WACOSS in its submission on the Draft Decision, which accepted:[554]

> ... Western Power's proposal to move to a combination of minimum standards and performance targets to enable it to earn rewards on a target-by-target basis. It is reasonable for Western Power to earn some part of the service standard bonus where it meets some, but not all of the performance targets.

1886. In the Draft Decision, the Authority was satisfied that as the proposed new 'minimum standards' SSBs levels correspond to the 97.5 per cent probability of exceedence (**PoE**) performance – relating to a defined statistical distribution – the SSBs are sufficiently detailed and complete to enable a user to determine the value represented by the reference service at the reference tariff. The Authority noted that additional information on the detail of the SSBs is provided by the corresponding service standards targets (**SSTs**), which are informed by the 50 per cent PoE levels from the same defined statistical distributions. On this basis, the Authority considers that the proposed minimum standard SSBs meets the requirement for SSBs under section 5.6 of the Access Code.

1887. At the same time, the Authority in its Draft Decision was satisfied that the 'minimum standard' specification of the SSBs is reasonable as it addresses the disproportionate penalty effect, while not detracting from the information that allows the user to determine the value represented by the reference tariff, as noted above. The Authority considers that such an approach helps to ensure that the objectives for the gain sharing mechanism at section 6.21 of the Access Code are achieved.

Transmission system service standards benchmarks

1888. This section considers both the requirement for transmission service standards, and the relevant SSB minimum standards.

Circuit Availability

1889. Western Power proposed in September 2011 to retain the transmission Circuit Availability SSB for the third access arrangement period. Western Power stated that retention of this service standard recognised 'the importance of security of the transmission network for customers that receive transmission and distribution reference services'.[555] The Authority agreed in the Draft Decision that this SSB should be retained.

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554 WACOSS 2012, *WACOSS Submission on the ERA's Draft Decision*, www.erawa.com.au, p. 18.

555 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 90.

1890. Western Power further proposed to set the transmission Circuit Availability SSB for the third access arrangement period at a lower 'minimum standard' (97.3 per cent) than the current access arrangement benchmark (98 per cent) (see Table 177 above and Figure 25 below). Western Power stated that the proposed minimum standard SSBs for the third access arrangement period, including the proposed Circuit Availability minimum standard SSB, were set in accordance with:[556]

- meeting a level of service that is likely 97.5 per cent of the time where higher levels reflect better performance (that is a 97.5 per cent PoE level) based on the historical data for the past five years (or alternatively a 2.5 per cent PoE level where lower levels reflect better performance);[557]
- the likelihood of achieving better service due to the forecast expenditure; and
- comparison with the current (access arrangement) SSBs.

1891. As noted above, the Authority accepted in the Draft Decision that SSBs need to be configured to minimum standards, and that setting the minimum standard SSB level is a reasonable approach to address the potential penalty discontinuity associated with section 6.26 of the Access Code.

1892. In the case of the transmission Circuit Availability measure, the Authority further considered that:

- the performance over the recent 60 months of historic data does not appear to exhibit any statistically significant trend improvement in transmission circuit availability (Figure 25), hence application of a (stationary) statistical distribution of best fit to derive the initial target levels for the third access arrangement period is acceptable;[558]
- any improvement in performance in the third access arrangement period, such as from the Mid West Energy Project improving Circuit Availability in the north country region, would be picked up as an improvement in the SSB level in the fourth access arrangement period, provided that the method to derive the SSB and SSAM targets remained unchanged;
- the method used to derive the minimum standard SSB at the 97.5 per cent PoE is acceptable.

1893. The Authority in its Draft Decision noted that the 97.5 per cent PoE level derived from the five years of historical data used for the Circuit Availability calculation suggests a minimum standard of 97.8 per cent, given Western Power's method. However, Western Power proposed to adjust the level of the SSB down by 0.5 per

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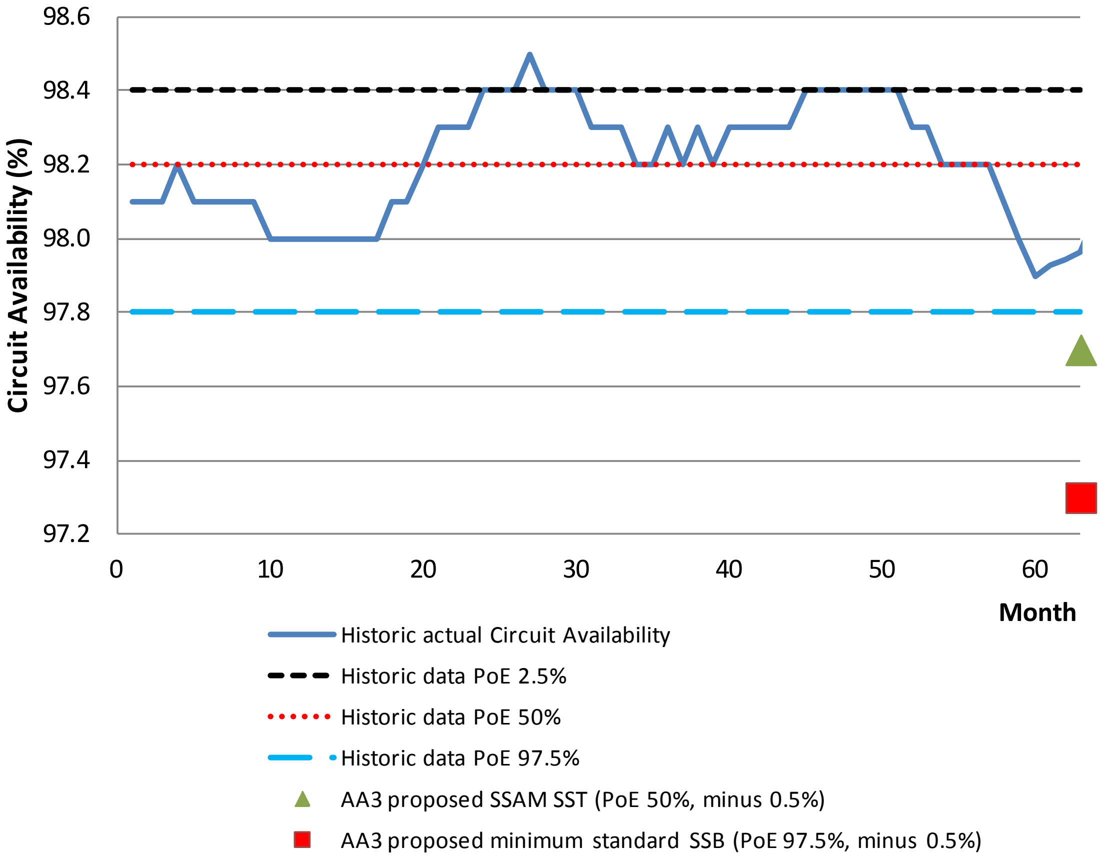
556 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92.

557 Western Power further states that a 'period of five years ensures that the effects of year-on-year volatility in performance is minimised and is consistent with the period used by the Australian Energy Regulator in determining targets for the Service Target Performance Incentive Scheme (Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92).

558 A simple OLS regression has an R^2 of 0.38, when the last three observations are removed. The Authority also notes that it accepted that there would not be improvement in the transmission network performance over AA2 (see Economic Regulation Authority 2009, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, July, p. 82).

cent – to be 97.3 per cent. Western Power stated that this adjustment was to account for the proposed increased level of capital works during the third access arrangement period.

Figure 25 Circuit availability – historical performance and proposed revised SSB and SST (September 2011)



Note: **SSB** = Service Standard Benchmark; **SSAM SST** = Service Standard Adjustment Mechanism Service Standard Target

Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 112; Western Power 2011, embedded spreadsheet in *Response to GB8 and GB11*, www.erawa.com.au, December, p. 3.

1894. However, based on analysis by GBA, the Authority in its Draft Decision considered that a 0.2 per cent reduction in the minimum standard was justified.

1895. The Authority in the Draft Decision thus required that the ‘minimum standard’ Circuit Availability service standard benchmark be set at 97.6 per cent. This is the estimated 2.5 per cent PoE level derived from the application of a Weibull distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during the third access arrangement period. Western Power accepted this requirement in its revised proposed access arrangement (May 2012).

1896. The foregoing analysis was based on 5 years of historic data through to 2010/11. More recent 2011/12 data for Circuit Availability performance has now been provided by Western Power. Accordingly, the Authority has updated the estimates for the Circuit Availability benchmark. The revised 97.5 per cent PoE level is

97.9 per cent (see **Appendix 3** for detail). Reducing this by 0.2 per cent gives a SSB for Circuit Availability of 97.7 per cent.[559]

Required Amendment 23

The minimum standard Circuit Availability SSB should be set at 97.7 per cent. This is the estimated 97.5 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during the third access arrangement period.

Table 184 below provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).

Transmission individual customer service measure

1897. A new service standard measure was proposed by Western Power in its proposed revisions to its access arrangement for transmission services in the third access arrangement period – the Individual Customer Service Measure. This is defined as the percentage of transmission users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:

- an account manager for the full 12 month period;
- an annually reviewed customer service management plan; and
- an invitation to participate in an annual satisfaction survey.

1898. The Authority did not consider that this measure provided incentive for Western Power to improve its transmission networks service performance. Accordingly, the Authority in the Draft Decision required that Western Power must either not implement the measure, or, to warrant the resources involved, include in a reporting element relating to the outcomes of the satisfaction survey.

1899. Western Power in its amended access arrangement information (May 2012) states that it will not implement the measure as an SSB, as it does not have data at this point to set a reasonable target for the customer satisfaction survey. However, Western Power notes that it still intends to proceed with the elements set out in paragraph 1897, and to begin to collect data on the outcomes of the customer satisfaction survey. The Authority is satisfied that this approach is reasonable.

[559] Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to **Appendix 4** for further detail).

Other transmission service standards

1900. In its proposed revised access arrangement, Western Power proposed to discontinue a number of the existing AA2 transmission service standard measures for the third access arrangement period (see the 'np' cells in Table 177) These are:

- System Minutes Interrupted (for both meshed and radial transmission network) - the summation of MW minutes of unserved energy at substations which are connected to the meshed transmission network divided by the system peak MW for included services, where a lower value of system minutes interrupted indicates a higher standard of service;

- Loss of Supply Events – defined as the frequency of events where the loss of supply exceeds two benchmarks (0.1 system minutes and 1.0 system minutes), where lower values on the two measures indicate a higher standard of service; and

- Average Outage Duration – the sum of all minutes of unplanned outage divided by the total number of unplanned outage events, where a lower value indicates a higher standard of service.

1901. The Authority in its Draft Decision did not accept Western Power's arguments for discontinuing these measures. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 32

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed and radial circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and
- Average Outage Duration, measured in minutes.

1902. However, Western Power has not accepted the Authority's required amendment as set out in the Draft Decision. To this end, Western Power in its amended access arrangement information (May 2012), stated that it does not accept the amendment because:[560]

- its proposed reference service measures meet the requirements of the Access Code

- the Authority's proposed network-based measures are not required under the Access Code

- Western Power's existing reporting requirements and the commitment in its September 2011 submission to report on additional transmission network

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[560] Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 183.

performance measures, allows stakeholders to separately assess the performance of the transmission and distribution networks and to compare Western Power's performance with network businesses in other jurisdictions

- transmission network measures do not represent the actual experiences of customers receiving a transmission reference service because the performance of the reference service is significantly better than the performance of the transmission network
- transmission network performance is likely to have a greater effect on customers receiving a distribution reference service
- including transmission network events in SAIDI and SAIFI preserves the compliance and financial incentives to perform on the transmission network.

1903. In response, the Authority considers – as noted in its Draft Decision – that transmission network performance is a key component for the performance of all reference services, including for reference services for large customers connected to the transmission network.[561] Section 5.1 of the Access Code is clear that service standards are required for each reference service.

1904. The Authority accepts that the transmission performance standards may have shortcomings with regard to measuring the service level for transmission reference tariff customers. However, the Authority considers that Western Power has not proposed an alternative, acceptable suite of measures that more closely tracks the outcomes for transmission reference services.[562]

1905. Submissions from stakeholders supported retaining the existing transmission service standard measures. WAMEU stated that 'the removal of these measures will provide an avenue for Western Power to avoid a clear assessment of transmission performance'.[563]

1906. The Authority's view is that the current suite of transmission service performance measures provides a proxy for service performance relating to transmission reference services. To omit these performance measures would diminish, rather than enhance, outcomes against the requirement under section 5.6 of the Access Code to implement SSBs that are reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

1907. In this context, the Authority notes that inclusion of Loss of Supply Event Frequency and Average Outage Duration measures, in addition to the overall transmission Circuit Availability measure, are consistent with, and allow comparison with, the transmission network performance outcomes in the National Electricity Market. The Authority notes that these measures were introduced for the current access

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561 Reference services for large customers connected to the transmission network include the transmission reference tariffs TRT1 and TRT2.

562 The transmission individual customer service measure proposed by Western Power was not accepted in its proposed form by the Authority. Western Power has subsequently chosen not to implement the measure.

563 WAMEU 2011, *Submission*, www.erawa.com.au, November.

arrangement on the basis that transmission benchmarks 'should be consistent with those that apply to transmission businesses in the National Electricity Market'.[564]

1908. The Authority notes that Western Power will continue to report on these measures under its other reporting requirements. However, the requirement for SSBs for reference services under sections 5.1 and 5.6 of the Access Code means that these measures should be retained, as set out above.

1909. With regard to the System Minutes Interrupted measure, Western Power states that:[565]

> Further, Western Power does not believe it is appropriate to include the system minutes interrupted measure as an SSB because:
>
> - the measure is not considered to be statistically sound and is not included in revenue determinations for other transmission businesses
>
> - the measure is not independent of the other transmission network measures that the Authority is proposing to include as SSBs

1910. Western Power notes that System Minutes Interrupted measure was considered by the ACCC when establishing the original transmission service standards for the National Electricity Market, but was replaced by the Loss of Supply Event Frequency Measure due to the measure's unsound statistical properties. These properties relate to the potential for stochastic weather or other unpredictable events to cause variation, which cannot be adequately captured by a one-point measure such as an average, or addressed through exclusions.[566]

1911. As a consequence, the Authority has further considered this issue and accepted that the System Minutes Interrupted measure has some less than desirable statistical characteristics. Nevertheless, having reviewed the original consultant's report on this matter, the Authority is not convinced that these issues are sufficient to outweigh the benefits of retaining the measure at this point in time.

1912. Furthermore, the Authority notes that the original analysis observed that all measures are subject to these issues, to a greater or lesser degree, and that exclusions can assist in overcoming these statistical problems.[567] Given this, the Authority notes that the exclusions for the System Minutes Interrupted measure relate to:[568]

> - Unregulated transmission assets.
>
> - Outages shown to be caused by a fault or other event on a '3rd party system' e.g. intertrip signal, generator outage, customer installation.

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564 Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 104.

565 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 183.

566 SKM 2003, *Transmission Network Service Provider – Service Standards: Final Report*, www.accc.gov.au, Appendix F, p. 74.

567 SKM 2003, *Transmission Network Service Provider – Service Standards: Final Report*, www.accc.gov.au, Appendix F, p. 76.

568 Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 8.

- Force majeure events.

1913. 'Force majeure' is defined under the Access Code as 'facts or circumstances beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome'.[569] Force majeure may be defined more broadly, as including:[570]

> ...circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:
>
> - fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature..

1914. The Authority therefore considers that there are reasonable grounds for exclusion of events that cause System Minute Interruptions beyond those considered to be reasonable under good electricity practice. The Authority also considers that the move to minimum standards SSBs should help to ensure that this measure does not set an unreasonable level of performance.[571]

1915. The Authority is particularly concerned to ensure that there are incentives to maintain radial networks performance, as these networks – unlike meshed networks – do not have redundancy. In this context, the Authority accepts that the Loss of Supply Event Frequency and Average Outage Duration measures together can provide an equivalent performance measure to System Minutes Interrupted, but notes that these measures are not disaggregated for radial networks.

1916. Accordingly, the Authority considers that the System Minutes Interrupted SSB measure provides a useful indicator of performance in relation to transmission reference services, particularly for radial networks, and should be retained.

1917. The Authority notes that Western Power could consider collecting disaggregated data for Loss of Supply Event Frequency and Average Outage Duration – for meshed and radial networks separately – with a view to substituting these disaggregated measures for the System Minutes Interrupted measures in the fourth access arrangement.

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569 Western Australian Government, *Electricity Networks Access Code 2004*, www.slp.wa.gov.au, p 22.

570 Australian Energy Regulator 2011, *Final: Electricity transmission network service providers Service target performance incentive scheme*, www.aer.gov.au, App. E.

571 For example, the deterioration in the System Minutes Interrupted performance by Western Power in 2010-11, to 4.8 system minutes, was due largely to a pole top fire on the single circuit Merredin-Carrabin-Yerdillon-Southern Cross 66 kV line, which resulted in a loss of 3.45 system minutes (Geoff Brown and Associates 2012, *Technical Review*, www.erawa.com.au, p 30). The Authority notes that the resulting level of performance would still have met the proposed minimum standard for this measure for the third access arrangement of 5.0 system minutes (Table 184).

Required Amendment 24

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed and radial circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of 0.1 to 1 minute duration and greater than 1 minute duration; and
- Average Outage Duration, measured in minutes.

Table 184 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).

1918. The Authority has received updated historic performance data from Western Power that includes the most recent 2011-12 performance data. Accordingly, the Authority has updated its estimates of the transmission SSBs and SSTs for the third access arrangement (Table 184 – see **Appendix 3** for detail).[572]

[572] Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to **Appendix 4** for further detail).

Table 184 Transmission SSBs and SSTs for the third access arrangement period

	SSB	SST	Distribution of best fit
Circuit availability (per cent)	97.9 – 0.2 = 97.7	98.3 – 0.2 = 98.1	Smallest extreme value
System minutes interrupted			
Meshed (minutes)	12.5	-	Logistic
Radial (minutes)	5.0	1.9	Percentile estimate
Loss of supply event frequency			
0.1 to 1 minute (events)	33	24	Percentile estimate
Greater than 1 minute (events)	4	2	Percentile estimate
Average outage duration (minutes)	886	698	Weibull

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on data supplied by Western Power

Distribution network service standard benchmarks

1919. This section considers both the requirement for distribution service standards, and the relevant SSB minimum standards.

SAIDI and SAIFI

1920. In its proposed revisions to its access arrangement (September 2011), Western Power proposed to retain for the third access arrangement period most of the distribution network unplanned SAIDI and SAIFI SSBs from the current access arrangement, but with two changes:

- exclude the unplanned SAIDI and SAIFI 'SWIN total' measures; and
- amend the retained SAIDI and SAIFI measures to include transmission outages.

Discontinuing SWIN total measures for SAIDI and SAIFI

1921. The Authority accepted in the Draft Decision that the 'SWIN total' measures for both planned and unplanned distribution network SAIDI and SAIFI would continue to be reported as part of Western Power's licence compliance obligations. The Authority also agreed that the remaining SAIDI and SAIFI measures will capture performance by feeder category. The Authority noted that the 'SWIN total' measures do not contribute to the distribution network SSAM. On that basis, the Authority accepted the proposal to discontinue the reporting of the SAIDI and SAIFI 'total SWIN' SSBs.

Incorporating transmission outages in the SAIDI and SAIFI measures

1922. Western Power proposed to incorporate transmission outages in the remaining SAIDI and SAIFI measures.

1923. Western Power was, in essence, seeking to remove the network outage duration and frequency measures from the transmission network service standards and incentives, and to incorporate these into SAIDI and SAIFI respectively.

1924. However, the Authority in its Draft Decision considered that separate information for the performance of the distribution and transmission networks – as is currently the case – allows distribution network users or applicants to assess the value of a reference tariff.

1925. The Authority also had significant concerns that the effect of this change would be to dilute the attribution of overall performance to distribution and transmission networks, and as a corollary, to obscure priorities for improvement. This change also would diminish the ability of large transmission-connected users or applicants to determine the value represented by a reference service at a reference tariff, and hence would not be consistent with the requirements of section 5.6 of the Access Code.[573]

1926. In addition, as noted above, the Authority did not accept Western Power's argument that transmission networks performance is unrelated to the provision of reference services, whether these be for large transmission-only customers, or for distribution customers.

1927. Finally, the Authority considered that the definition of the SSAM targets for the distribution network for 2011/12 need to be maintained – as these accounted for investments in improved service standard performance that were paid for by users during the current access arrangement period. Redefining these targets is not in the interests of network users, particularly as the Authority considers that the investments made to improve these service levels during the current access arrangement period need to be accounted for (see paragraph below).

1928. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 33

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

573 The Access Code states (p. 65):

5.6 A service standard benchmark for a reference service must be: (a) reasonable; and (b) sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

1929. In its Amended Access Arrangement, Western Power does not accept this amendment because:[574]

- the service distribution customers receive is affected by transmission network interruptions and therefore is relevant in assessing the value of distribution reference services
- Western Power's proposed reference service measures meet the requirements of the Access Code
- the Authority's proposed network-based measures are not required under the Access Code
- Western Power's existing reporting requirements and commitment to report on additional transmission network performance measures allow stakeholders to separately assess the performance of the transmission and distribution networks.

1930. However, the Authority does not accept Western Power's assertions, as:

- The Authority is of the view that retaining the transmission network SSBs is desirable, so as to meet the requirements of the Access Code, specifically section 5.6 (see above).
- Distribution customers will be able to determine the value of a reference service by considering both the transmission and distribution SSBs:
  - for duration of interruptions, combining both SAIDI on the distribution network, based on network type, plus system minutes interrupted on the transmission network; and
  - for frequency of interruptions, combining SAIFI with Loss of Supply Event Frequency on the transmission network.
- Existing reporting requirements do not provide a substitute for achieving section 5.6 of the Access Code.
  - Nevertheless, the Authority notes that the Electricity Distribution Licence Performance Reporting Handbook requires Western Power to report on performance measures relating to distribution network customers. These performance measures include data relating to the frequency and duration of outages for distribution licence customers, whether or not they arise from a distribution or transmission outage.[575]

1931. Accordingly, the Authority requires that the definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

574 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 187.

575 Economic Regulation Authority 2011, Electricity Compliance Reporting Manual, www.erawa.com.au p. 91.

Required Amendment 25

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

Setting SSBs for SAIDI and SAIFI

1932. As with the transmission network measures, the Authority accepted in its Draft Decision that the SSB for these distribution network service standard measures should be configured as a minimum standard SSBs based on the 97.5 per cent PoE analysis, so as to avoid a large penalty discontinuity for under-performance.

1933. However, the Authority considered that setting the minimum standard SSBs on the basis of the most recent five years of data would not take account of the investments made during the current access arrangement, paid for by customers, to improve performance on these measures.

1934. Accordingly, the Authority considered that setting the third access arrangement targets based on the more recent three years data would more fairly reflect the investments that were made in the current access arrangement to improve performance on the SAIDI and SAIFI measures. Western Power accepted these amendments.

1935. The Authority notes in this context that Western Power has proposed that if transmission network events are excluded from the SAIDI and SAIFI measures, another set of service standard benchmarks would apply, as set out in Table 79 of its revised proposed access arrangement (May 2012). These estimates differ from those estimated by the Authority in the Draft Decision. The Authority wrote to Western Power seeking insight as to why this was the case, and a response was received in August 2012.[576]

1936. In its response, Western Power observed that the differences between the amended proposed SSBs and those of the Authority in its Draft Decision are generally small, and reflect different interpretation of test statistics and rounding. The exception to this observation is the Rural Short SAIDI and SAIFI SSBs, where the Authority utilised estimates based on the Box-Cox and Johnson transformations. Western Power noted that these approaches require a manual reverse-transformation process, which introduces a greater risk of error, indicating that this was one reason why these statistical approaches were not adopted.

1937. The Authority accepts that the use of the Box-Cox and Johnson transformations are not straightforward, particularly in interpreting the confidence level data back into the non-transformed units. For these reasons, the Authority has reconsidered its approach and elected to exclude these distributions.

1938. However, the Authority considers that even with this exclusion, the method chosen by Western Power for selection of distribution of best fit for the revised proposed

576 Western Power 2012, *Response to question FD15*, www.erawa.com.au.

access arrangement is not consistent with its originally stated approach. Western Power state that:

> The distribution of best fit can be based on the largest p-value and the lowest Anderson-Darling (**AD**) test statistic. Western Power chose its distributions based on their p-value whereas it appears the ERA used the AD statistic. Both methods are statistically valid and this is why the differences are not significant. Western Power proposes that the distribution of best fit be based on the p-value to be consistent with the selection criteria documented in the report... provided in February.

1939. The Authority considers that, consistent with Western Power's original approach, selection of the statistical distribution with the lowest Anderson-Darling value is preferred, provided that the accompanying p-value is greater than 0.05. The p-value confirms whether the data is consistent with the chosen distribution at the 95 per cent confidence level. This preferred approach is summarised by Minitab (the software program adopted by both Western Power and the Authority for determining the statistical properties of the data) as follows:[577]

> The Anderson-Darling statistic measures how well the data follow a particular distribution. For a given data set and distribution, the better the distribution fits the data, the smaller this statistic will be.
>
> Use the corresponding p-value (when available) to test if the data come from the chosen distribution. If the p-value is less than a chosen alpha (for example, 0.05), then reject the null hypothesis that the data come from that distribution.

1940. Generally, the Authority considers that the best approach is to choose the distribution with the lowest Anderson-Darling value, and then adopt it, provided that $p > 0.05$.

1941. The Authority has received updated historic performance data from Western Power that includes the most recent 2011-12 performance data. Accordingly, the Authority has updated its estimates of the distribution SSBs and SSTs for the third access arrangement (Table 185 – see **Appendix 3** for detail).[578]

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[577] Minitab 2012, *What is the Anderson-Darling goodness of fit test statistic?*, http://www.minitab.com/en-TW/support/answers/answer.aspx?ID=731&P=0&R=312&M=43&S=45, accessed 9 August 2012.

[578] Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to **Appendix 4** for further detail).

Required Amendment 26

Western Power is required to adopt the SAIDI and SAIFI service standard benchmark measures estimated by the Authority from the most recent three years of data (Table 185 provides the Authority's estimates – see Appendix 3 for detail).

Table 185 Revised SAIDI and SAIFI SSBs and SSTs for the third access arrangement period (based on 3 years of historic data)

	SSB	SST	Distribution of best fit
SAIDI (minutes)			
CBD	39.9	20.3	Percentile
Urban	183.0	136.6	Percentile
Rural short	227.8	207.8	Weibull
Rural long	724.8	582.2	Largest extreme value
SAIFI (events)			
CBD	0.26	0.14	Logistic
Urban	2.12	1.36	2 parameter exponential
Rural short	2.61	2.27	Lognormal
Rural long	4.51	4.06	Lognormal

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on historic data supplied by Western Power

Call centre performance

1942. The Authority in its Draft Decision broadly accepted Western Power's proposal for the Call Centre Performance measure, including the proposed SSBs.

1943. However, the Authority did not accept Western Power's proposed definition for this measure.[579] The Authority considered that the wording of the definition raised the prospect that calls could be left ringing, or once answered, simply diverted to an automated message. The performance standard should instead be defined to:

579 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 13.

- start at the point the phone starts ringing at the call centre;
- exclude the period of time related to automated messaging – as occurs with the Australian Energy Regulator's Service Target Performance Incentive Scheme; and
- limit the time of any automated messaging.

1944. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 35

The Authority requires that for the Call Centre Performance service standard benchmark measure:

- The definition point 'First speaking with a person in 30 seconds or less' be amended to:
  - First speaking with a person in 30 seconds or less, but excluding the time that the caller is connected to an automated interactive service (to a maximum of three minutes) that provides substantive information or elicits the caller's postcode, and which informs within the first 30 seconds that the call will be responded to by a human operator within three minutes.'
- The definition point 'First receiving an automated interactive message service message in 30 seconds or less' be deleted.
- The definition point 'The fault call response time commences when the postcode is automatically determined or when a valid postcode is entered by the caller or when the call is placed in the queue to be responded to by a human operator' be amended to:
  - 'The fault call response time commences when the call first enters the call centre and starts ringing.'

The Authority requires the exclusions be defined as follows:

One or more of:

- Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller.
- Calls abandoned during the first three minutes of an automated message.
- Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator.
- All telephone calls received on a major event day which is excluded from SAIDI and SAIFI.
- A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

1945. WACOSS in its submission on the Draft Decision, supported the establishment of a (modified) call centre performance measure.

1946. Western Power has not accepted this amendment, stating that:[580]

- Western Power's proposed definition of call centre performance meets the Access Code requirements – it provides an expectation to distribution reference service customers of the value provided to them by the call centre

- Western Power has addressed the Authority's concerns by amending its proposed definition of call centre performance to give precedence in the measure to a call placed in the queue for response by a human operator (while maintaining the relevance of the automated interactive message service) and has made it clear that a call left ringing will not be included as a call responded to.

1947. The Authority accepts that automated interactive messaging can provide information to customers. The Authority's concern in the Draft Decision was to ensure that such messaging did not provide an avenue to divert the caller from an operator, where this response was sought. The Authority notes that Western Power has revised the definition of the proposed Call Centre Performance measure by including performance in relation to calls where the caller elects to be placed in a queue to be responded to by a human operator, whether at the beginning of the call, or following an automated message regarding power interruptions in the relevant area and related restoration information.

1948. The Authority therefore accepts the revised Call Centre Performance Definition as proposed by Western Power.[581]

The Authority has received updated historic performance data from Western Power that includes the most recent 2011-12 performance data. Accordingly, the Authority has updated its estimates of the Call centre performance SSB for the third access arrangement (

1949. Table 186 – see **Appendix 3** for detail).[582]

Required Amendment 27

Western Power is required to adopt the Call Centre Performance service standard benchmark measure estimated by the Authority from the most recent five years of data (

Table 186 provides the Authority's estimates – see Appendix 3 for detail).

[580] Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 193.

[581] Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 194.

[582] Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to **Appendix 4** for further detail).

Table 186 Revised Call centre availability SSBs and SSTs for the third access arrangement period (based on 5 years of historic data)

	SSB	SST	Distribution of best fit
Call centre availability (percentage of calls responded to in 30 seconds)	77.5	87.6	Logistic

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on historic data supplied by Western Power

Circuit availability

1950. As noted above, the Authority does not accept that transmission related performance measures should be mixed with distribution network measures. The Authority accordingly required that Western Power remove transmission network Circuit Availability as a distribution network service standard benchmark measure in the Draft Decision. Western Power accepted this required amendment.

Worst performing feeders

1951. WAMEU's submission in 2011 suggested that the service standards be expanded to incorporate performance on the worst performing feeders.

1952. The Authority in its Draft Decision for the third access arrangement period noted that it had proposed this measure in its Draft Decision on the current access arrangement. In a submission subsequent to the Draft Decision on the current access arrangement, Western Power requested that the Authority reconsider the need for a worst performing feeder measure for the reason that the SAIDI and SAIFI measures for the 15 per cent of customers served by the worst performing feeders would fulfil the same role in indications of service quality as the existing SAIDI and SAIFI measures for Rural-long feeders. Western Power indicated that the measures for the 15 per cent of customers served by the worst performing feeders would be predominantly served by rural-long feeders, and the difference in recorded SAIDI and SAIFI measures, although different, is not of sufficient magnitude to materially affect a user's assessment of the value of a reference tariff (Table 187).[583]

[583] Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 112.

Table 187 Comparison of SAIDI and SAIFI for the worst 15 per cent of customers served and for rural-long feeders

	SAIDI		SAIFI	
	Worst 15% of customers served	Rural-long feeders	Worst 15% of customers served	Rural-long feeders
2005/06	631	472	5.47	3.69
2006/07	728	624	6.30	4.72
2007/08	711	611	6.03	4.99
2008/09	711	573	5.91	4.27

Source: Economic Regulation Authority 2009*, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network,* www.erawa.com.au*,* p. 112.

1953. In its Final Decision on the current access arrangement, the Authority accepted Western Power's contention that there would be substantial overlap between measures of SAIDI and SAIFI for the 15 per cent of customers served by the worst performing feeders and for the existing category of rural-long feeders. The Authority also observed that there is a strong correlation between the measures for the two categories of customer groups. On this basis, the Authority considered that the SSBs for the rural-long feeders adequately capture service reliability for the worst affected customers and the Authority did not maintain the requirement for amendment of the proposed access arrangement revisions.

1954. The Authority also noted that the reliability of supply to the worst served customers may be measured by the number of customers entitled to payments for outages lasting more than 12 hours under Section 19 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

1955. WACOSS in its submission on the Draft Decision stated that:

> ....Western Power should report the performance of the worst ten or fifteen per cent of feeders. Such reporting would provide greater transparency around Western Power's progress in addressing the performance of poorly performing parts of the network and provide a level of encouragement to improve performance of such parts of the network towards median levels. The Council notes that Western Power argued against such reporting on the basis that the reporting would inevitably focus on rural long feeders, which form the full set of such poorly performing feeders.
>
> However, this problem can be addressed by reporting performance of the worst ten or fifteen per cent of feeders within each of the categories of CBD, urban, rural short, and rural long feeders. A number of east coast jurisdictions take this approach to enable transparent tracking of poorer sections of the network over time. It would not be onerous for Western Power to provide this data.

1956. However, the Authority remains of the view that there is sufficient existing information on performance in relation to worst served customers, as these customers are concentrated in the rural areas. The Authority therefore does not require that Western Power develop such a reporting tool.

MAIFI

1957. The Authority notes that it gave attention in its final decision for the first access arrangement to a service standard that captures momentary interruptions, in particular the inclusion of a service standard benchmark for the average number of momentary interruptions of one minute or less per distribution network customer per year (as reflected by a Momentary Average Interruption Frequency Index (**MAIFI**)). The Authority did not persist in this requirement due to a submission from Western Power that it was not practically possible to accurately produce MAIFI data without a multi-million dollar investment.[584]

1958. Western Power noted as part of its access arrangement information (September 2011):[585]

> During the stakeholder engagements that informed this revisions submission, customers indicated that they would value Western Power reducing the number of momentary interruptions, as even an instantaneous break in electricity supply can lead to machinery having to be reset, significantly disrupting productivity.
>
> We have listened to this feedback and are taking action to reduce the number of momentary interruptions, however, we do not currently have sufficient data to include a measure of momentary interruptions as a service standard benchmark. We will seek to improve monitoring of momentary interruptions during AA3, so that we will be in a stronger position to consider their inclusion as a service standard benchmark for AA4.

1959. The Authority in its Draft Decision noted the stakeholder feedback reported by Western Power. On this basis, the Authority considered that MAIFI is an important measure which provides information on service levels that are of value to customers.

1960. In its Draft Decision, the Authority required Western Power to collect monthly data for the average number of momentary interruptions of one minute or less per distribution network customer for each of the distribution sub-classes (CBD, Urban, Rural short and Rural long), and report these as part of its annual service standards benchmarks report to the Authority. This would provide a basis for establishing service standard benchmarks and service standard targets for the fourth access arrangement period for a Momentary Average Interruption Frequency Index measure.

1961. Western Power accepted this amendment.

Streetlighting service standards

1962. The only change proposed by Western Power in its proposed access arrangement revisions for the Streetlighting service standard measure was to shift results for major regional towns to be under the broader category of Metropolitan regions.

1963. The benchmarks for the third access arrangement period are the same as for the current period.

1964. The Authority accepted this proposal in the Draft Decision.

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584 Economic Regulation Authority 2007, *Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, www,erawa,com.au, March, paragraph 184.

585 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 88.

1965. Citelum in its submission on the Draft Decision suggested that the Streetlighting service standard benchmarks (SSB's) proposed are at best basic.

1966. Citelum further noted that it had conducted an audit of the City of Perth's Public Lighting Network and identified in excess of 76 streetlights not working. This in one sense echoes the points made in WALGA's submission during the first round of consultation, which noted that the measurement of street light repair standards continues to be questioned by Local Governments.

1967. The Authority notes that the SSBs relate to repair times, not to the proportion of lights that are not working. It is up to the local government authority to notify lights that are not functioning properly, and there will always be a proportion that has problems. The Authority considers that this is a matter for appropriate monitoring and enforcement of standards.

1968. That said, the Authority considers that the broader points in Citelum's submission warrant consideration in an appropriate forum. The scheduled review of the Access Code in relation to the arrangements for street lighting could provide such a forum.

Exclusions

1969. Western Power included a new clause 4.5.2 in the proposed revisions for the third access arrangement period which relates to exclusions. This clause stated that 'exclusions are usually first considered when the Authority publishes its service standard performance report under section 11.2 of the Code', and proposes that any 'exclusion accepted by the Authority in such a report will be an exclusion for the purposes of [the] access arrangement and the Code'.[586]

1970. In the Draft Decision, the Authority did not consider that the proposed clause was acceptable on the basis that it provided incentive for Western Power to introduce exclusions without review at the time of the annual service standard report.

1971. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 38

Only those exclusions that are approved by the Authority in the access arrangement may be included for the purposes of the service standards measures. The proposed clause 4.5.2 must be removed.

1972. Western Power did not accept this amendment in its revised proposed access arrangement revisions. Rather, Western Power makes it clear in the amended access arrangement information that the clause was not intended to allow introduction of exclusions without the Authority's approval.

1973. To provide greater clarity, Western Power proposes to replace clause 4.5.2 in the revised proposed access arrangement with the following alternate wording:[587]

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586 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 17.

587 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 197.

> Whether or not particular circumstances meet the criteria to be an exclusion, such that the resulting units are not included in the measure, may be considered by the Authority when it publishes Western Power's actual service standard performance against the service standard benchmarks under section 11.2 of the Code. Where the Authority accepts an exclusion in such a report, it will be an exclusion for the purposes of the application of this access arrangement and the Code.

1974. The Authority considers that this amended clause addresses its concern, and accepts Western Power's revised proposed amendment to clause 4.5.2.

WAFarmers Proposed Service Standard

1975. In its submission to the Authority on Western Power's proposed access arrangement revisions, WAFarmers raised concerns regarding the conduct of Western Power staff and contractors when entering and conducting work on farm land. Although Western Power's Customer Charter sets out clear guidelines for Western Power's staff and contractors, WAFarmers view is that this is often not complied with and considers that a reportable service standard measuring Western Power's performance in this area is necessary.

1976. The Authority in the Draft Decision noted that dealing effectively with issues relating to access to private property is an important component of a service provider's delivery of an efficient level of service. The Authority considered that a service standard benchmark would provide a useful measure of whether Western Power is complying with good electricity industry practice, and required that a service standard measuring compliance with Western Power's Customer Charter should be introduced:

> **Draft Decision Amendment 39**
>
> The proposed revised access arrangement should include a service standard measuring compliance with Western Power's Customer Charter. The benchmark must be set at 100 per cent.

1977. WAFarmers in its submission on the Draft Decision supports this amendment. WAFarmers notes that assessment of Western Power's service delivery needs to consider both access to, and conduct on, properties. WAFarmers states that responses by Western Power to complaints by members of WAFamers through Western Power's web-based processes have not been satisfactory and demonstrate why change is required. WAFarmers and Western Power have agreed to work to develop programs to improve customer service.

1978. Western Power has not accepted this amendment in its revised proposed access arrangement revisions. Western Power states that the measure would not meet a number of its own criteria for assessing service standard benchmark measures, because:[588]

- the aspect of service that is targeted by this performance measure would only be valued by a relatively small proportion of customers

[588] Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 198.

- the Access Code requires service standard benchmarks for each reference service. Access to land is not a reference service and therefore the Access Code does not require a service standard benchmark relating to access to land

- data is not available to support the setting of a minimum service standard using the same approach as used to set the other minimum service standards

- the outcome can be distorted in a number of ways – those who own or lease land that Western Power needs to access may make it difficult for Western Power to provide notification

- Western Power can amend its customer charter at any time to reflect the actual level of service.

1979. The Authority notes that the criteria established by Western Power to assess SSB performance measures are not directly relevant to the Authority's decision whether to introduce a new SSB.

1980. Western Power suggests that there are barriers to its performance in this area that might be better managed by other action:[589]

> From a practical perspective, Western Power does not hold or have access to accurate information about the owner or lessee of land and it is not always obvious where property boundaries are. This means that there are often difficulties in identifying the appropriate person to inform about intended access. This is particularly difficult in rural areas when assets are located on private land, often well inside private property boundaries.
>
> Securing access to, or developing accurate information on, the owner or lessee of land would further improve notification to landholders. Western Power is aware, for example, that the Western Australian Department of Agriculture and Food (DAFWA) has a database that provides up-to-date information on farm boundaries and landowner and/or lessee contact details for farming properties. However, for privacy reasons Western Power is not able to access to those details without permission from those on the database. Without access to this database or development of an alternative, Western Power will continue to have difficulty providing notification of property access consistent with the current Customer Charter.

1981. In light of Western Power's submission, the Authority has reconsidered this issue. The Authority acknowledges Western Power's intent to maintain good practice – as set out in its customer service charter. The Authority also notes the practical barriers to achievement of the desired outcome. In light of these practical barriers, the Authority encourages Western Power to work with WAFarmers to resolve this problem, and notes the dialogue which has been opened, particularly the undertaking to develop or access a database of land owners that wish to be contacted prior to Western Power entering their land.

1982. The Authority therefore will remove its requirement for an SSB in relation to compliance with Western Power's customer service charter.

1983. That said, in the meantime, the Authority also will evaluate a licence condition that requires reporting by Western Power of the number of complaints in relation to land access and conduct during access. Should improvement to acceptable levels of

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589 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 198.

complaint not be forthcoming through voluntary action by Western Power, then the Authority will consider establishing the licence condition, which could be subject to penalties for non-compliance.

PRICING METHODS, PRICE LIST AND PRICE LIST INFORMATION

Access Code Requirements

1984. Section 5.1(e) of the Access Code requires an access arrangement to include pricing methods under Chapter 7 of the Access Code.

1985. Section 7.1 of the Access Code defines “pricing methods” to mean the structure of reference tariffs included in an access arrangement, which determines how target revenue is allocated across and within reference services.

1986. Section 7.2 of the Access Code provides that an access arrangement may contain any pricing methods; provided that the pricing methods collectively meet the objectives set out in sections 7.3 and 7.4 and otherwise comply with the Chapter 7. A note under section 7.2 gives examples of tariffs that may result from pricing methods, indicating that tariffs or parts of tariffs may be set to take into account matters such as different classes of users, different voltage levels, different connection points, demand levels, energy quantities and times of use.

1987. Sections 7.3 and 7.4 of the Access Code set out the objectives for pricing methods, as follows:

> 7.3 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) reference tariffs recover the forward-looking efficient costs of providing reference services; and
>
> (b) the reference tariff applying to a user:
>
> (i) at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and
>
> (ii) at the upper bound, is equal to, or is less than, the stand-alone cost of service provision.
>
> 7.4 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) the charges paid by different users of a reference service differ only to the extent necessary to reflect differences in the average cost of service provision to the users; and
>
> (b) the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively; and
>
> (c) the structure of reference tariffs enables a user to predict the likely annual changes in reference tariffs during the access arrangement period; and
>
> (d) the structure of reference tariffs avoids price shocks (that is, sudden material tariff adjustments between succeeding years).

1988. Section 7.5 of the Access Code requires that the Authority, in reconciling any conflicting objectives for the pricing methods or determining which objective is to prevail, should have regard to the Code objective, and where necessary must permit the objectives of section 7.3 to prevail over the objectives of section 7.4.

1989. Section 7.6 of the Access Code provides guidance for establishing components of tariffs:

> 7.6 Unless an access arrangement containing alternative pricing methods would better achieve the Code objective, for a reference service:
>
> (a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and
>
> (b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

1990. Section 7.7 of the Access Code requires that tariffs be established as "postage stamp" tariffs in certain circumstances:

> 7.7 The tariff applying to a standard tariff user in respect of a standard tariff exit point must not differ from the tariff applying to any other standard tariff user in respect of a standard tariff exit point as a result of differences in the geographic locations of the standard tariff exit points.

1991. Section 7.9 of the Access Code provides for "prudent discounts" to be made available to some users:

> 7.9 A service provider may propose in its access arrangement to discriminate between users in its pricing of services to the extent that it is necessary to do so to aid economic efficiency, including:
>
> (a) by entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and
>
> (b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1992. In sections 7.9 and 7.10 of the Access Code, "equivalent tariff" means:

(i) For a reference service – the reference tariff; and

(ii) For a non-reference service – the tariff that it is reasonably likely would have been set as the reference tariff had the non-reference service been a reference service.

1993. Section 7.10 of the Access Code provides for discounts for users connecting distributed generation plant:

> 7.10 If a user seeks to connect distributed generating plant to a covered network, a service provider must reflect in the user's tariff, by way of a discount, a share of any reductions in either or both of the service provider's capital-related costs or non-capital costs which arise as a result of the entry point for distributed generating plant being located in a particular part of the covered network by:
>
> (a) entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and

(b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1994. Section 7.11 of the Access Code requires an access arrangement to include a detailed policy setting out how discounts under sections 7.9 and 7.10 will be implemented, including a detailed mechanism for determining when a user will be entitled to receive a discount and for calculating the discount to which the user will be entitled.

1995. Section 7.12 of the Access Code requires that the value of any tariff equalisation contributions be recovered as a tariff component from users of the distribution network:

> 7.12 If an amount is added to the target revenue under section 6.37A and is intended to be recovered from users of reference services through one or more reference tariffs, then the recovery must have the objective of:
>
> (a) applying only to users of reference services provided in respect of exit points on the distribution system; and
>
> (b) being equitable in its effect as between users referred to in section 7.12(a); and
>
> (c) otherwise being consistent with the Code objective.

Price list and price list information

1996. Section 5.1(f) of the Access Code requires an access arrangement to include a price list under Chapter 8 of the Access Code. A "price list" is defined in the Access Code as the schedule of reference tariffs in effect in an access arrangement for a covered network.

1997. Chapter 8 of the Access Code sets out the requirements and processes for a service provider to submit price lists to the Authority for approval and for the Authority to approve or not approve a proposed price list.

1998. An access arrangement may, or may not, include a requirement for a service provider to submit price lists to the Authority for approval. Under section 4.36 of the Access Code, the Authority may require price lists to be submitted to it for approval if it considers that to do so would improve the operation of the access arrangement.

1999. If a service provider's access arrangement requires the service provider to submit price lists to the Authority for approval section 8.1 of the Access Code requires that the service provider must submit a proposed price list to the Authority at least 45 business days before the start of each pricing year (other than the first pricing year). A proposed price list must be accompanied by price list information. "Price list information" is defined as a document which would reasonably be required to enable the Authority, users and applicants to understand how the service provider derived the elements of the proposed price list and to assess the compliance of the proposed price list with the access arrangement.

2000. Sections 8.2 to 8.6 of the Access Code set out the process for the Authority to approve or not approve a proposed price list. The Authority is obliged to approve a proposed price list if it determines that the proposed price list complies with the price control and pricing methods in the service provider's access arrangement.

2001. Sections 8.7 and 8.8 of the Access Code require a service provider to submit price lists to the Authority, even if the access arrangement does not require the service provider to submit a copy of its price lists to the Authority for approval. In these circumstances, the role of the Authority is to publish the submitted price list and price list information.

Current Access Arrangement

2002. "Pricing methods" are included in the current access arrangement at section 9 and indicate the allocation of costs to particular reference services and particular charges of reference tariffs.

2003. A price list (2009/10) was included in the current access arrangement at Appendix 5. Subsequent to the Authority's approval of the current access arrangement, this price list was revised to incorporate variations to reference tariff charges made in accordance with the price control for the years 2010/11 and 2011/12.

2004. The current access arrangement includes constraints on changes to reference tariffs at times of revisions of the price list. These constraints are:

- +/- (CPI + 13 percentage points) for the transmission network; and
- +/- (CPI + 18 percentage points) for the distribution network.

Proposed Revisions

2005. As noted in paragraph 199, for the purposes of calculating the maximum target revenue each year when setting annual tariffs, Western Power proposed a number of changes in its proposed revisions to the access arrangement:

- the published CPI data relating to the most recent December quarter compared to the December quarter in the previous year would be used rather than the March quarter, which is the requirement in the existing access arrangement;
- the formula for calculating the maximum target revenue was amended to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year so the difference in actual revenue compared to the target revenue must be estimated and then recalculated in the subsequent financial year. In the current access arrangement, this was noted in the text of the access arrangement but not explicitly included in the formula; and
- the requirements for calculating the maximum revenue cap were changed from "will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" to "will use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]".

2006. As set out in paragraphs 196 to 197 above, Western Power proposed to include all network access services, whether they are reference or non-reference services, within the revenue cap.

2007. As noted in paragraph 198, Western Power proposed a new method of calculating the side-constraints for the transmission and distribution network which will vary annually based on CPI, percentage change in revenue requirements, correction factors (including an adjustment for under and over-recovery of revenue, adjustments to revenue from the current access arrangement and the TEC) and an additional 2 per cent. The formula for calculating these side constraints is contained in Western Power's revised proposed revisions to the access arrangement.[590]

2008. In the access arrangement information, Western Power noted that its pricing methods, prudent discounting policy and policy on discounts for distributed generation remain unchanged from the current access arrangement.[591]

2009. Western Power did not propose adopting its revised side constraint for the first year of the third access arrangement period and instead proposed an amendment to the Price List Information to incorporate "tariff increase moderations."[592] This proposed amendment is discussed further in the Authority's considerations below.

2010. Western Power proposed introducing four new reference tariffs in relation to the proposed bi-directional reference services. In the Price List Information included with the proposed revisions, Western Power noted that implementation of the new tariffs would not be complete until six months after approval of the third access arrangement. Consequently, the forecast number of customers on these tariffs was zero for the 2012/13 year. Western Power anticipated that in the second year of the third access arrangement period customer numbers would be known and able to be forecast with some degree of accuracy so would be included in the 2013/14 estimate of revenue.[593]

2011. Western Power proposed amending the streetlight tariff to:

- update the list of streetlight asset types to include all types currently in use; and
- separate the list of streetlight asset types into "current" and "obsolete" asset types, with "current" assets being those that are still offered for installation and "obsolete" assets being those no longer offered.

Considerations of the Authority

Target Revenue Cap

2012. In the Draft Decision, the Authority did not approve the transmission network revenue cap and the distribution network revenue cap proposed by Western Power. Consequently, Western Power was required to amend its proposed revised Price List and Price List Information for 2012/13 to be consistent with the approved transmission network revenue cap and distribution network revenue cap target.

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590 Proposed revised access arrangement, p. 31-34.

591 Proposed revised access arrangement information, p. 308.

592 Proposed Price List Information section 8.14.

593 Proposed revised Price List, p. 7.

Draft Decision Amendment 40

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision.

2013. In response to the Draft Decision, Western Power has not accepted this amendment and has instead amended the 2012/13 Price List and Price List Information to reflect the revenue caps proposed by Western Power in the revised proposed revisions to the access arrangement.

2014. As the Authority has not accepted Western Power's revised proposed revisions to the access arrangement, the Authority requires the Price List and Price List Information for 2012/13 to be amended to be consistent with the transmission network revenue cap and distribution revenue cap approved by the Authority in this Final Decision.

Required Amendment 28

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Final Decision.

2015. In the Draft Decision, the Authority acknowledged that the March CPI is not available until the end of April so cannot be incorporated in time for a Price List to be submitted to the Authority at least 45 business days before the start of pricing year. Consequently the Authority accepted Western Power's proposed amendment to use the published CPI data relating to the most recent December quarter.

2016. The Authority noted that the proposed amendment to the formula for calculating the maximum target revenue, to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year, is in line with the text of the current access arrangement and reflects how it has been done in practice. Consequently, the Authority accepted Western Power's proposed amendment to the maximum target revenue formula.

2017. As discussed in paragraphs 1213, Western Power's revised proposed revisions to the access arrangement include a further amendment to the maximum target revenue to adjust for differences in the real TEC value that arise due to differences between forecast and actual inflation. The Authority has not accepted this adjustment and has required the revised proposed revisions to be amended as set out in Required Amendment 20.

2018. In the Draft Decision the Authority did not accept Western Power's proposed amendment of the requirement in the current access arrangement (from a requirement that Western Power "use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" to a requirement that Western Power "use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]"). The Authority considered that making such an amendment would be to the potential disadvantage of users as the requirement to not exceed the revenue cap is weakened. The Authority noted that the current access arrangement would still enable the revenue target to be slightly exceeded if it was not reasonably possible to stay within the maximum revenue cap.

2019. The Authority accordingly required the following amendment to the proposed revised access arrangement.

> **Draft Decision Amendment 41**
>
> Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended to be consistent with clause 5.27 and 5.38 of the current access arrangement.

2020. In response to the Draft Decision, Western Power has not accepted the required amendment. In the amended access arrangement information, Western Power notes that it is:

> … concerned the previous [current] wording ("will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap") creates an upward bias on price increases due to the K-factor adjustment always catching up for a short-fall in revenue from previous years (given the requirement to always set prices to collect less than the revenue target).

2021. In the revised proposed revisions to the access arrangement, Western Power has deleted both the current wording and its proposed revised wording, resulting in the following amended sections 5.6.1 and 5.7.1:

> 5.6.1 The *transmission system* revenue cap for *revenue cap services* determines the maximum transmission *revenue cap service* revenue (MTR_t) for Western Power's *transmission system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement, Western Power will use its reasonable endeavours to ensure that the actual transmission revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.~~
>
> 5.7.1 The *distribution system* revenue cap for *revenue cap services* determines the maximum distribution *revenue cap service* revenue (MDR_t) for Western Power's *distribution system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement, Western Power will use its reasonable endeavours to ensure that the actual distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.~~

2022. The Authority agrees that there are difficulties with both the current wording of these provisions and the wording proposed by Western Power in its proposed revisions to the access arrangement.

2023. The current wording is confusing as it is not actually correct that the revenue caps (TR_t and DR_t) determine the maximum revenue caps (MTR_t and MDR_t). The maximum revenue caps are made up of a number of variables as shown below. It would be more correct to say something along the lines of "are used to determine".

$$MTR_t = TR_t + TAA2_t + TK_t$$

$$MDR_t = DR_t + TEC_t + DAA2_t + DK_t$$

2024. Furthermore, as Western Power notes in the amended access arrangement information, Western Power's ability to influence the actual revenue it will earn in any particular year is limited to the prices that are set in the price list. Consequently, a requirement for Western Power to ensure actual revenue cap service revenue is within a reasonable margin of the maximum revenue cap (as required under the current sections 5.6.1 and 5.7.1) is arguably impractical and unreasonable.

2025. The Authority considers the intention of section 5.6.1 and 5.7.1 was that reasonable endeavours should be made to ensure forecast revenue for year t, based on the proposed price list for year t, did not exceed the maximum revenue cap.

2026. Consequently, the Authority requires the following amendment.

Required Amendment 29

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended as follows:

> 5.6.1 The *transmission system* revenue cap for *revenue cap services* ~~determines~~ is used to determine the maximum transmission *revenue cap service* revenue (MTR_t) for Western Power's *transmission system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement,~~ Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ transmission revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.
>
> 5.7.1 The *distribution system* revenue cap for *revenue cap services* ~~determines~~ is used to determine the maximum distribution *revenue cap service* revenue (MDR_t) for Western Power's *distribution system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement,~~ Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.

2027. Under the current access arrangement only reference services are included within the revenue cap. As the Access Code only requires the Price List to cover reference services, under the current access arrangement there is no need to allocate any of the revenue cap to other services when preparing the Price List.

2028. However, as set out earlier in this Final Decision, the Authority has accepted Western Power's proposal to modify the price control to include all network access services, whether they are reference or non-reference services, within the revenue cap. Consequently, target revenue will need to be allocated in some way between reference and non-reference revenue cap services. The Authority understands Western Power intended to achieve this by including non reference access service revenue in forecast revenue recovered when preparing the Price List Information.

Prior to the Draft Decision, Western Power advised the Authority that it had erroneously deducted standby services from its forecast transmission revenue in the proposed 2012/13 Price List Information. Standby services are non reference network access services and therefore now fall within the revenue cap under Western Power's proposed revised access arrangement.

2029. In the Draft Decision the Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 42

The proposed revised Price List for 2012/13 must be amended to include revenue from standby services in forecast transmission revenue.

2030. In response to the Draft Decision, Western Power accepted the amendment and submitted a revised 2012/13 Price List which includes revenue from standby services in forecast transmission revenue. The Authority considers that Western Power has adequately complied with Draft Decision Amendment 42.

2031. In the Draft Decision, the Authority agreed in principle with Western Power's proposed approach of including non reference access service revenue in forecast revenue recovered when preparing the Price List Information and required the proposed revisions to the access arrangement to specifically state this methodology.

Draft Decision Amendment 43

The proposed revised access arrangement must be amended to explain how the revenue cap will be allocated between reference and non reference access services.

2032. In response to the Draft Decision, Western Power has accepted the required amendment and revised clause 6.3.1 of the revised proposed revisions to the access arrangement to state that the revenue cap will be allocated between reference and non-reference access services by deducting the expected non-reference service revenue from the revenue cap to determine the reference service revenue.

Side Constraints

2033. The current access arrangement includes annual side constraints of:

- +/- (CPI + 13 percentage points) for the transmission network; and
- +/- (CPI + 18 percentage points) for the distribution network.

2034. The values of these side constraints reflect the increases in target revenue for transmission and distribution in the "smoothed" tariff path for the access arrangement period and do not make provisions for rebalancing of tariffs.

2035. The side constraints Western Power proposed for the third access arrangement period are more complex and provide for a reference tariff to be increased so that the proportional increase in nominal revenue from the reference tariff from the previous year is less than or equal to the proportional increase resulting from:

- inflation escalation;

- the year to year increase in target revenue that was determined in the financial model for the access arrangement;
- adjustments to target revenue that result from carry-over and cost pass-through mechanisms under the price control; and
- a further two per cent.

2036. The formula allowed a proportional increase in revenue from the reference tariff sufficient to recover increases in costs, carryovers from the previous years and cost pass-through, plus a further two per cent. The additional two per cent allows for "rebalancing" of reference tariffs, i.e. for there to be a change in relative reference tariffs reflecting a shift in cost recovery between services.

2037. In the Draft Decision the Authority noted there was a slight difference between the specification of the formula in relation to the value of adjustments to the annual revenue cap as a proportion of the revenue cap for transmission and for distribution. In practice, the difference in the specification of the adjustment parameters would probably not have a material effect on the side constraints unless there is a large departure of actual revenue from the values of target revenue that were determined in the financial model for the access arrangement. Western Power advised that it had adopted different formulae as the likelihood of revenue variation differs for each service. However, the Authority considered it would be clearer to users if the formula for each service was consistent.

2038. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 44

Western Power must revise the specification of the adjustment parameters in the side constraints for transmission and distribution to make them consistent.

2039. In response to the Draft Decision, Western Power has accepted this amendment and has amended the distribution side constraint to be consistent with the transmission side constraint. The Authority considers the requirement to make both side constraints consistent has been complied with.

2040. Western Power notes that, in preparing the 2012/13 price list for the revised proposed revisions to the access arrangement, it identified that the side constraint proposed in the initial submission did not operate as expected with q^{xy}_{t} on the numerator and q^{xy}_{t-1} on the denominator. Western Power states:

> It was found that changes in customer numbers, energy consumption or demand between 2011/12 and the forecasts for 2012/13 restricted changes in prices. This is not the intention of the side constraint. The purpose of the side constraint is to mitigate the effects of price shock on individual customers during AA3, not restrict price movements due to changes in customer numbers, energy consumption or demand between years. To address this unintended outcome of the side constraint Western Power has refined the formula to have q^{xy}_{t} on both the numerator and denominator.

2041. The Authority has reviewed the revised formula and considers it results in a better mechanism to mitigate price shock as the constraint is applied to the change in prices for a reference service between years rather than to the change in revenue.

2042. The submission from WACOSS in response to the Draft Decision considers that the side constraints on changes in relative tariffs among tariff classes should be set at a real rate of change of 1 per cent rather than the 2 per cent proposed by Western Power. WACOSS does not consider that Western Power has demonstrated that current tariff levels contain cross-subsidies or are otherwise inappropriate. WACOSS is concerned that permitting 2 per cent real rebalancing of tariffs might result in the movement of costs to those customer classes where users are less able to avoid tariff increases in the short term, which it considers would result in less efficient tariffs.

2043. The Authority notes that section 6.18.6 of the National Electricity Rules specifies the side constraint that must be applied to regulated network tariffs in the National Electricity Market. The formula is essentially the same as that proposed by Western Power (including Western Power's revised specification of the numerator and denominator as set out in paragraph 2040 above) and includes a factor of 2 per cent.

2044. The Authority considers a factor of 2 per cent is appropriate to provide sufficient scope for rebalancing to reflect changes in costs whilst ensuring customers are protected from price shocks. However, the Authority recognises the concerns raised by WACOSS that such a mechanism may result in higher tariffs to some customer classes and that such rebalancing should be scrutinised. As the purpose of the rebalancing factor is to reflect changes in the distribution of costs between reference services to ensure tariffs are cost reflective, the Authority will require Western Power to provide details in the Price List Information setting out any such rebalancing and the reasons for it.

Required Amendment 30

The Price List Information must set out details of rebalancing between reference services and the reasons for it with supporting information.

2045. As most of the parameter values of the side constraint (in particular the inflation and carry-over under the revenue cap) will only become known at the time of the annual revision of reference tariffs, it is not possible to predict changes in the reference tariffs ahead of these parameter values being determined.

2046. The Authority notes the concerns raised in the Verve Energy submission about the proposed amendments to the side constraints on the basis that the proposed methodology could result in uncertain and variable values and unexpected and/or unwarranted outcomes.

2047. However, the Authority notes this is the consequence of the nature of the revenue cap price control, which incorporates carryovers and cost pass-throughs. That is, under the revenue cap price control Western Power is able to earn a fixed level of revenue, so any increase in customer volumes and numbers would lead to a reduction in tariffs and, conversely, a decrease in customer volumes and numbers would lead to an increase in tariffs.

2048. In its Final Decision in relation to the second access arrangement period, the Authority accepted that providing a regulated business with an opportunity to re-balance tariffs and tariff charges will generally provide the business with the opportunity to develop efficient tariff levels and structures. However, the revisions to reference tariffs in the second access arrangement period included a large increase in reference tariffs. The Authority considered that allowing a margin in the side constraints on tariff changes for rebalancing of tariffs would, potentially, have the effect of exacerbating price shocks for some network users. Therefore, the Authority considered that a balance between objectives of efficiency in the level and structure of reference tariffs and avoiding price shocks was best achieved by setting the side constraints on adjustments to reference tariffs at a level just sufficient to provide for recovery of target revenue and a smooth path of tariff changes over the second access arrangement period.

2049. However, as the target revenue approved by the Authority in this Final Decision will lead to considerably lower tariff increases than experienced in the past, the Authority considers Western Power's proposed side constraint meets the requirement of section 7.4(d) of the Access Code to mitigate the effects of price shock on individual customers.

Pricing Methods

2050. As noted above, Western Power stated in the access arrangement information that its pricing methods are unchanged from the current access arrangement. As set out in the Price List, Western Power determines the value of individual reference tariffs and the individual charges of the reference tariffs by applying a cost allocation model. Under this model, costs are allocated to cost pools and location zones, then to customer groups (corresponding to reference services), and then to charges that make up each reference tariff. Criteria for the allocation of costs relate generally to:

- the characteristics of a user at a connection point and measures of each user's proportional share of use of the network relative to other users; and
- the amount of costs that can be allocated to a user at a connection point such that the total charges paid by the user under a reference tariff are an amount generally between the incremental cost of service provision and the stand-alone cost of service provision.

2051. In its submission during the first round of public consultation, the WAMEU noted that under a revenue cap there was a tendency for regulators to not be involved in tariff setting as the allowed revenue is fixed and such an approach can lead to the service provider developing tariffs that are not cost reflective. As a result, the pricing signals that tariffs are intended to provide can be muted or even counterproductive.

2052. The WAMEU submission also noted that, whilst much of the capital expenditure is provided to address increases in peak demand, often the tariffs are set in terms of consumption. The submission noted that it is widely recognised that the increasing penetration of air conditioning has been the major contributor to the increasing demands on networks and that, as the air conditioning load is heavily weather dependent, it has also led to a reduction in network load factors, due to the high demand occurring for relatively short periods.

2053. The WAMEU submission expressed concern that the continuing approach for tariffs to reflect consumption means that there is a trend for high load factor consumers to subsidise consumers with low load factors. Whilst this loss of cost reflectivity provides a benefit to low load factor consumers, it also avoids providing price signals to those who are causing the bulk of the need for increased peak capacity in the networks.

2054. The WAMEU submission recommends that the Authority should require Western Power to develop tariffs that:

- are cost reflective as this provides equity to all; and
- provide a strong price signal to consumers that have high demands for relatively short periods of time.

2055. The WAMEU submission contended that, unless there are tariff changes along these lines, Western Power will continue to seek large increases in revenue to manage the increase in peak demand that could be mitigated if there was a more appropriate tariff structure.

2056. The submission from Landfill Gas and Power during the first round of public consultation noted that it has found the network tariffs to be reasonable since their inception but considers there is now a need for a new class of "time of use" tariffs in order to promote more efficient use of the network, which is especially relevant in managing the costs of system peaks. It noted the current "time of use" tariffs adhering to the traditional broadly defined "peak" and "off-peak" time periods have no regard for seasonality, public holidays or other "shoulder" features and noted that, whereas the Wholesale Electricity Market (**WEM**) facilitates the development of innovative "time of use" tariff signals, these signals are dissipated when combined with the averaging implicit in the network tariffs.

2057. The submission from WACOSS in response to the Draft Decision encourages the Authority to require Western Power to develop off-peak tariff arrangements. WACOSS notes that such tariffs are available in other jurisdictions in Australia and considers that off-peak tariffs could and should be introduced within the AA3 period to encourage demand to shift from peak to off-peak times, enabling significant savings in capital expenditure. WACOSS also notes that it would be very concerned if compulsory time of use tariffs were introduced.

2058. The Authority considers some of the points raised in submissions have merit. However, in considering the pricing methods under the proposed access arrangement revisions, the Authority does not have a role in approving levels and structures of reference tariffs to the level of detail that would enable the Authority to impose particular tariff structures, such as those proposed in these submissions.

2059. The role of the Authority in assessing and approving the magnitude and structure of particular reference tariffs is limited. The Authority is required to consider whether the proposed pricing methods will result in reference tariffs meeting the requirements of section 7.2 of the Access Code, and the objectives of sections 7.3 and 7.4 of the Access Code. The efficiency requirements of these objectives are broad, requiring only that the reference tariffs recover the forward-looking efficient costs of providing reference services and that the reference tariff applying to a user recovers an amount of revenue that is greater than the incremental cost of service provision and less than the stand-alone cost of service provision.

2060. Submissions from Griffin Power and ERM Power to both the first round of public consultation and to the Draft Decision take the view that the current practice of allocating 20 per cent of Transmission Use of System (**TUOS**) charges to generators is fundamentally flawed. ERM Power considers this leaves generators exposed to open-ended changes in network charges that are not quantifiable at the time of a power station investment decision. ERM Power provided the Authority with a paper prepared by Synergies Economic Consulting, which it considers sets out the shortcomings of Western Power's current arrangements for setting TUOS charges and identifies an alternative pricing model.

2061. Synergies Economic Consulting argues that the TUOS charge allocation to generators is inconsistent with the Access Code, because:[594]

- it imposes a risk on prospective generator investors to which they are individually unable to respond once the generation investment is made, with the consequence that generation entry will be delayed or less capacity will be installed than would otherwise be the case;
- it presents weaker incentives for load to reduce peak demand and for generators to increase peak output than would otherwise be the case, thereby reducing the efficiency of investment in, operation of and use of the network;
- there are no offsetting efficiency benefits arising from the generator TUOS charges, such as improved decision making over location, lower transaction cost or guaranteed access to network services for generators, that offset these outcomes; and
- the regulation of transmission in Australia reduces the importance of TUOS as a signal of future efficient Transmission Network Service Provider (**TNSP**) investment.

2062. As set out in the Draft Decision, the Authority has considered the points in the Synergies Economic Consulting paper and the proposed alternative approach. The Authority is not convinced, however, that the proposed generator TUOS charge allocation is inconsistent with the economic efficiency objectives of the Access Code for the following reasons:

- all market participants face risks relating to future network charges – if generators do not wish to bear those risks, then they should be able to manage the identified risks through contractual arrangements;
- the incentives for loads to manage their peak demands remain significant; and
- allocation of TUOS charges to generators does provide some locational signalling, as Western Power's transmission pricing model allocates transmission costs on the basis of the costs of the network assets used by a connection at any particular location, which vary across Western Power's network.

2063. Nevertheless, the Authority considers that this is a complex issue and consideration of the proposed alternative arrangements should be incorporated with that of other potential reforms to improve the overall market arrangements – as part of the review of the Access Code.

2064. Taking the above matters into account, the Authority is satisfied that the pricing methods applied by Western Power are consistent with the objectives of sections 7.3 and 7.4 of the Access Code.

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594 Synergies Economic Consulting 2012, *Revision of the Generator Transmission Use of System Charges in Western Australia: A report for NewGen*, www.erawa.com.au, p. 40.

Proposed Price List for 2012/13

2065. In the proposed revisions to the access arrangement, Western Power did not apply its proposed side constraints to the proposed price list for the 2012/13 financial year.[595] Instead it noted in the Price List Information[596] that its intention at the start of the third access arrangement period was to set all prices to their cost reflective levels after many years of flat scaled increases.

2066. Western Power noted in the Price List Information that:

> Unfortunately, this method results in unrealistic outcomes for some tariffs. In order for some customers not to be unduly disadvantaged in year one, some of the tariff increases and decreases have been slightly modified.
>
> Specifically, increases for RT4 and RT10 were slightly reduced to be more in line with the increases in other tariffs. As the increases for RT6-RT8 were lower than average, the decision was made to slightly increase these tariffs to enable moderation of large increases in other tariffs. This approach is similar to how the side-constraints will operate during AA3.
>
> This decision means that revenue from RT4 is not between incremental and stand-alone costs in the first year. However, RT4 revenue should move to the cost reflective level over the course of the AA3 period (with inter-year movements subject to the side constraints proposed in the Access Arrangement).

2067. In the Draft Decision the Authority noted there was significant variation in Western Power's estimate of the incremental and stand-alone cost of service provision costs between the approved Price List Information for 2011/12 and the proposed Price List Information for 2012/13. The changes between the two years varied between a reduction of 0.1 per cent in the incremental cost for the RT2 reference tariff and a 56 per cent increase in the incremental cost for the RT4 reference tariff. There also appeared to be little relationship between the change in incremental cost of service and the stand-alone cost of service provision for each reference tariff. For example, the incremental cost for the RT6 tariff increased by 33 per cent compared with the previous year whereas the stand-alone cost of service provision reduced by 1 per cent.

2068. The Authority considered that, given that Western Power stated it had not changed its pricing methods from the current access arrangement, the significant variations appeared strange. Western Power did not provide any explanation or information about why its assessment of incremental and stand-alone costs varied so significantly from the current approved price list.

2069. The Authority also noted that the estimated costs would reduce as a result of the Authority not approving Western Power's proposed target revenue.

2070. The Authority accordingly required the following amendment to the proposed revised access arrangement.

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595 Access Arrangement Information, p. 314.

596 Appendix F.2, p. 73.

Draft Decision Amendment 45

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision. Western Power should include commentary to explain any material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information.

2071. In response to the Draft Decision, Western Power's amended access arrangement information states it has accepted this amendment. In the 2012/13 Price List Information, Western Power notes that it has amended its estimates of incremental and stand-alone costs to exclude the cost of the Tariff Equalisation Contribution, which had previously been included, on the basis that it does not form part of network costs. Other than this, Western Power considers there are no material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information.[597]

2072. The Authority notes that Western Power has not based its revised 2012/13 Price List on the target revenue costs approved in the Draft Decision. Furthermore, the Authority's Final Decision has not approved Western Power's proposed revised revenue caps. The Authority notes Western Power's statement that, other than removing the Tariff Equalisation Contribution, there are no material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information, however, there is insufficient information provided in the Price List to enable the Authority to confirm this. Consequently, the Authority does not consider Draft Decision Amendment 45 has been complied with.

Required Amendment 31

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Final Decision. Western Power should include sufficient information to enable a comparison with the estimate of incremental and stand-alone costs in the current 2011/12 Price List Information, and to explain any material variations.

2073. Section 7.5 of the Access Code requires that the Authority, in reconciling any conflicting objectives for the pricing methods or determining which objective should prevail, must have regard to the Code objective and, where necessary to reconcile a conflict, must permit the objectives of section 7.3 to prevail over the objectives of section 7.4. The effect of this is that the requirement that tariffs should be set somewhere between the incremental and stand-alone cost of providing the relevant service prevails over the requirement to avoid sudden material tariff adjustments between succeeding years.

2074. As discussed in paragraph 2066 above, Western Power's proposed Price List for 2012/13 included tariffs which did not meet this requirement. Accordingly, in the Draft Decision the Authority required the following amendment.

597 Western Power 2012/13 Price List Information p. 56

Draft Decision Amendment 46

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

2075. In response to the Draft Decision, Western Power states it has accepted this amendment and Table 15 of the revised 2012/13 Price List Information shows forecast revenue for each reference service is between incremental and stand-alone costs of service provision. The Authority considers Western Power has complied with the required amendment but, as the 2012/13 Price List Information must be updated as a result of this Final Decision, this requirement will be reviewed again as part of the Price List approval process.

Required Amendment 32

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

2076. In the Draft Decision the Authority noted there was a wide variation in the percentage change to specific tariffs for 2012/13 compared with 2011/12 ranging from -53 per cent to +118 per cent. Whilst the Authority recognised that, if Western Power had only been applying flat scaled increases over many years, there may be a divergence from their cost reflective levels, it considers that as far as possible whilst still complying with section 7.3 of the Access Code, any rebalancing should be phased in over a period of time so as to avoid sudden material tariff adjustments between succeeding years as required under section 7.4 (d) of the Access Code.

2077. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 47

Western Power's proposed side constraint must apply from the first year of the third access arrangement.

2078. In response to the Draft Decision, Western Power has accepted the amendment and revised the access arrangement so that the side constraint applies from the first year of the third access arrangement period. The Authority considers Draft Decision Amendment 47 has been adequately complied with.

Bi-directional Tariffs

2079. As set out in the Draft Decision, the Authority considers the views expressed in submissions in relation to further improvements such as consolidating the bi-directional tariffs with the existing exit only reference tariffs and more sophisticated time of use tariffs to better manage the cost of system peaks should be given consideration by Western Power in the future. However, given the general support expressed in submissions for the proposed tariffs and the pragmatic approach Western Power has taken of basing the proposed bi-directional tariffs on the proposed exit only tariffs, the Authority considers the proposed tariffs meet the requirements of sections 7.3 and 7.4.

2080. The Authority notes the Office of Energy's view that it would be helpful for pricing guidelines to be published in relation to non-reference bi-directional services for plant larger than 1 MVA. However, there is no requirement under the Access Code for guidelines for non-reference services to be published.

2081. As discussed above in paragraph 163 the threshold for the proposed business bi-directional tariffs of 1 MVA is consistent with the Access Code requirement for the use of average, non-locational tariffs for all connections below 1 MVA. Western Power has advised that the threshold of 1MVA will allow the reference service to cover the greater portion of the market for bi-directional services and that installations above 1MVA would be charged on the basis of the existing entry and exit reference services for distribution customers (A8 and B1).

Streetlight Tariffs

2082. In the Draft Decision, the Authority noted the points raised in WALGA's submission to the effect that the existing street lighting service model results in local governments being almost powerless to influence the level of service or cost and, as street lighting is a public good, the costs would be better shared between users and the public.

2083. A submission from Citelum[598] in response to the Draft Decision also raises concerns about the current model for street lighting services. Citelum considers that the regulated delivery model for public lighting would be better served if the service was classified as a negotiated service, regulation removed and all public lighting assets transferred to local government authorities.

2084. As set out in the Draft Decision, the Authority acknowledges there are different, and potentially better, models for recovering the cost of street lighting. However, for the purposes of this review, the Authority can only apply the requirements of the Access Code, which provides for Western Power to recover its efficient costs through network charges and requires that tariffs comply with sections 7.3 and 7.4 of the Access Code.

2085. In the Draft Decision, the Authority reviewed the updated list of streetlight asset types included in the proposed Price List for 2012/13. The Authority noted that Western Power has added 10 new asset types to the list of streetlight assets. However, all of the new asset types were included in Table 3 of the Price List, which relates to obsolete asset types. No submissions received during the first round of public consultation referred to the addition of new asset types. Given that the new types related to obsolete light types, the Authority was concerned these proposed changes might lead to increases in charges to users.

2086. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 48

Western Power's proposed additions to streetlight asset types must ensure existing assets are not charged on a higher band compared with the current access arrangement.

598 Citelum's submission notes it is a global leader in Urban Lighting and Traffic Management services for local public authorities and is interested in becoming a market participant in the Western Australian public lighting market.

2087. In response to the Draft Decision, Western Power has confirmed that no customers will be worse off and that the additional categories for obsolete light types simply make the prices for the obsolete streetlights more transparent to its customers. The submission from Citelum considered that developing individual item tariffs in relation to public lighting creates confusion for public lighting customers. However, no other submissions received have put this view. The Authority considers Draft Decision Amendment 48 has been adequately complied with.

ADJUSTMENTS TO TARGET REVENUE IN THE NEXT ACCESS ARRANGEMENT PERIOD

Access Code Requirements

2088. Sections 6.6 to 6.32 of the Access Code provide for the target revenue for an access arrangement period to be adjusted to reflect certain events, or outcomes of the previous access arrangement period. In the circumstances of the access arrangement for the Western Power Network, these sections of the Access Code provide (to the extent permitted by the terms of the access arrangement) for the target revenue for the fourth access arrangement period (due to commence on 1 July 2017) to be adjusted to take into account the relevant events or outcomes in the third access arrangement period.

2089. The events and outcomes that may give rise to adjustments to target revenue under these sections of the Access Code are:

- the service provider incurring certain costs during the third access arrangement as a result of unforeseen (force majeure) events (sections 6.6 to 6.8 of the Access Code);
- the service provider incurring greater or lesser non-capital costs or capital-related costs as a result of changes in the Technical Rules for the Western Power Network (sections 6.9 to 6.12 of the Access Code);
- the amount, nature and timing of new facilities investment in the third access arrangement being different to the forecast for that period, consistent with an investment adjustment mechanism set out in the access arrangement (sections 6.13 to 6.18 of the Access Code);
- demand growth and/or efficiency gains achieved by the service provider, consistent with a gain sharing mechanism set out in the access arrangement (sections 6.19 to 6.28 of the Access Code); and
- the service provider achieving service standards during the third access arrangement that are different to the service standard benchmarks established in the access arrangement, consistent with a service standards adjustment mechanism set out in the access arrangement (sections 6.29 to 6.32 of the Access Code).

Current Access Arrangement

2090. The current access arrangement includes adjustment mechanisms for unforeseen events and changes to the Technical Rules. These mechanisms allow for certain costs incurred by Western Power to be carried over from one access arrangement period to the next and, under the adjustment mechanism applying to changes in the Technical Rules, a carryover of benefits to the third access arrangement period.

2091. The current access arrangement includes an investment adjustment mechanism that allows for the carryover from one access arrangement period to the next period of costs or benefits arising from differences in forecast and actual capital costs associated with differences between forecast and actual new facilities investment. The investment adjustment mechanism applies only to certain classes of new facilities investment:

- new facilities arising from the connection of new generation capacity to the transmission or distribution network from 1 July 2009;
- new facilities investment arising from the connection of new load to the transmission system or distribution system from 1 July 2009;
- new facilities investment in relation to the augmentation of the capacity of the transmission system or distribution system for the provision of covered services from 1 July 2009; and
- new facilities investment undertaken for augmentation of the distribution system under the Regional Power Improvement Program and State Underground Power Program.

2092. The current access arrangement includes a gain sharing mechanism that provides a financial reward to Western Power for out-performance of the forecast of operating expenditure in the second access arrangement period.

2093. The current access arrangement includes provision for a deferral of revenue from the second access arrangement period with the deferred amount (escalated for inflation and by the rate of return) to be included in target revenue in the third or subsequent access arrangement periods.

2094. The current access arrangement includes an adjustment mechanism referred to as the "D-factor scheme" under which Western Power is able to carry-over to the third access arrangement period certain costs incurred in the second access arrangement period arising from a deferral of capital projects and from the implementation of demand management initiatives.

2095. The current access arrangement includes a service standard adjustment mechanism that provides a financial reward or penalty depending on Western Power's actual performance compared to benchmark service standard measures.

2096. Paragraphs 1196 to 1288 of this Final Decision outline the proposed adjustments to target revenue for the third access arrangement period in respect of outcomes and events from the current access arrangement.

Proposed Revisions

2097. In the proposed access arrangement revisions, Western Power maintained the adjustment mechanisms included in the current access arrangement, with the exception of the deferral of revenue. Western Power did not include provisions for deferral of revenue as it proposed to recoup the entire amount of the deferred revenue from the first to second access arrangement periods during the third access arrangement period.

2098. Western Power proposed a significant change to the service standards adjustment mechanism and a number of amendments to the existing adjustment mechanisms for the gain sharing mechanism and the D-factor.

2099. Western Power also proposed to amend the manner in which it treats depreciation when establishing the opening capital base for the fourth access arrangement period.

2100. The proposed revisions are discussed further below.

Considerations of the Authority

2101. The Authority has considered the proposed revisions to each adjustment mechanism separately as set out below.

Gain sharing mechanism and efficiency and innovation benchmarks

2102. The gain sharing mechanism provides an additional incentive to Western Power to achieve operating cost efficiencies during an access arrangement period as it ensures Western Power retains such benefits for five years from when the efficiency is achieved. Western Power proposed to adjust the gain sharing mechanism to:

- exclude costs relating to superannuation costs for defined benefit schemes, costs associated with non-revenue cap services, licence fees and the Energy Safety Levy from the calculation of the above benchmark surplus as it considers these costs to be outside its control;
- introduce an ex-post growth adjustment to the efficiency and innovation benchmark when calculating the above-benchmark surplus; and
- adjust the above-benchmark surplus formula to cater for the proposed five-year period for the third access arrangement period.

2103. Western Power also proposed to amend the current clause 5.14C of the access arrangement, which states that in any year in which an above-benchmark surplus is calculated to be a positive value but Western Power fails to meet service standard benchmarks for that year, the above-benchmark surplus for that year is deemed to be zero. Western Power proposed amending the clause (now renumbered to clause 7.4.3) to reflect the wording of section 6.26 of the Access Code:

> In any year in which an above-benchmark surplus is calculated to be a positive value the above-benchmark surplus does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks for that year as set out in section 4 of this access arrangement.

2104. In the Draft Decision, the Authority agreed that costs relating to superannuation for defined benefit schemes, licence fees and the Energy Safety Levy are outside the control of Western Power and that it is therefore reasonable that such costs should be excluded from the gain sharing mechanism. However, this was subject to Western Power having clearly identified the amounts of these costs in its forecast operating costs for the third access arrangement period so that, when the gain sharing mechanism is applied, there is no difficulty in excluding these costs from the original forecast operating expenditure as well as from the actual operating expenditure. The Authority noted that Western Power has provided these details in section 14.3.3 of the amended access arrangement information in Table 101 and, on that basis, accepted that sufficient information has been provided to enable the expenditure to be excluded from both forecast and actual operating expenditure. As noted in the Draft Decision, the Authority intends to amend its access arrangement information guidelines to ensure this information is disclosed in the regulatory accounts.

2105. Western Power's reason for excluding the cost of non-revenue cap services from the operation of the gain sharing mechanism is stated as:

> "The customer-driven nature of non-revenue cap services means that the operating costs will vary from the forecasts. For example, if we had forecast to undertake 100 units of an activity but were subsequently required to undertake 200 units to meet increased customer demands, costs would be increased and so would revenue. Similarly if customer demand was lower, then costs and revenue will be lower.
>
> If these costs were subject to the GSM it would provide increased incentive to reduce these costs, which could potentially result in a conflict with the need to respond appropriately and effectively to customers' requirements."[599]

2106. In the Draft Decision the Authority considered that, in principle, this was not unreasonable. However, there needs to be a clearly stated method of attributing costs to the non-revenue cap services that is applied consistently for both the forecast and actual costs. Without a clearly stated method there is a risk that Western Power will over-allocate actual costs to the non-revenue cap services to gain benefits under the gain sharing mechanism. The Authority required Western Power to provide details of the methodology it proposes to use. The Authority also noted its intention to amend its access arrangement information guidelines to ensure this information is disclosed in future regulatory accounts.

2107. As discussed above, Western Power has included scale escalation in its forecast operating expenditure for the third access arrangement period. Western Power proposes that a similar adjustment should be incorporated into the gain sharing mechanism by substituting the forecast scale factors used to derive the efficiency and innovation benchmark for the third access arrangement period, with the actual scale factors when calculating the above-benchmark surplus at the end of the third access arrangement period. Western Power considers it should not be rewarded or penalised for variations from forecast operating expenditure that are attributable to differences in the scale factors driving expenditure (such as customer numbers, line length, number of feeders or zone substation capacity) and that, conversely, customers should not pay more under the gain sharing mechanism because of slower growth.

2108. Western Power's proposed adjustment is similar in nature to its proposals to exclude costs over which it has no control and costs relating to non-revenue cap services discussed above. In the Draft Decision the Authority considered that, in principle, this is not unreasonable. However, there needs to be a clearly stated method for making this adjustment that includes establishing the scaling factors used in the forecast and verifying the actual scale factors. As discussed above, the Authority has not accepted Western Power's proposed scaling factors.

2109. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 49

Western Power must provide a clearly stated methodology for making this adjustment which is based on the scaling factors approved by the Authority in this draft decision and includes details of how actual scaling factors will be verified.

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599 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, pp 301 - 302.

2110. In response to the Draft Decision, Western Power notes in the amended access arrangement information that it has amended the access arrangement to include a "clearly stated method for making scale escalation adjustment to the efficiency and innovation benchmarks in response to this amendment". However, Western Power has based the method on its proposed scale escalation factors rather than those determined by the Authority in the Draft Decision.

2111. The Authority has reviewed the scale factors again as part of this Final Decision and determined the values to be used for calculating Western Power's target revenue. The scale factors used for the scale escalation adjustment must be consistent with those approved by the Authority as set out in Table 21.

2112. Western Power notes that the data used for the scaling factors will be verifiable against the Western Power Annual Report. The Authority is concerned that these parameters, although reported in the Annual Report, may not be independently audited as part of that exercise. The Authority requires that the actual values reported for scaling factors be independently audited.

Required Amendment 33

Western Power must amend the gain sharing mechanism methodology and values to use the scaling factors, including economy of scale factors, and operating costs approved by the Authority in this Final Decision. The actual values used for scaling factors must be independently audited. The audit must be carried out by an independent auditor approved by the Authority, with Western Power managing and funding the audit. The scope of the audit will be determined by the Authority.

2113. The Authority accepts the proposed changes to the above-benchmark surplus formula to enable it to be applied for five years as this is consistent with Western Power's proposed target revisions commencement date.

2114. The Authority notes the proposed revision to clause 7.4.3 is consistent with section 6.26 of the Access Code and accepts the proposed revision as reasonable given that it reflects the requirements of the Access Code. However, the Authority notes it is not clear how, in the event that service standard benchmarks are not achieved, it will be determined whether and to what extent there is a relationship between cost savings and the underperformance on service standards. Given this issue, an alternative would be to maintain the requirement of the current clause 5.14C, with a new proviso that "unless, or to the extent, that Western Power demonstrates to the satisfaction of the Authority that the above benchmark surplus is unrelated to Western Power failing to achieve the service standard benchmarks".

2115. In the Draft Decision the Authority accepted Western Power's proposed amendment on the basis that it complied with the Access Code, but requested that further consideration should be given by Western Power to the Authority's proposal as set out in paragraph 2114 above.

2116. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 50

Western Power must amend its proposed revision to clarify how, in the event that service standard benchmarks are not achieved, it will be determined how and to what extent there is a relationship between costs savings and the underperformance on service standards.

2117. In response to the Draft Decision, Western Power agrees that additional clarity would be useful. However, it notes that the circumstances of an event where a service standard benchmark is not achieved can vary significantly so, therefore, it would not be appropriate to state in the access arrangement how the relationship between cost savings and underperformance will be determined as the relevant factors may vary in each case. In the amended access arrangement, Western Power has provided a high level overview of the general process Western Power would follow to determine the relationship between cost savings and underperformance:

> If there is underperformance on a service standard in a year, Western Power will demonstrate to the Authority how and to what extent there is a relationship between cost savings and underperformance on that service standard, through consideration of:
>
> - which service standard benchmark has not been met in that year
> - an analysis of the causes for not meeting the service standard benchmark in that year
> - the categories of operating expenditure that impact on the achievement of that service standard benchmark
> - after normalising the operating expenditure in those categories for CPI, inflation and scale escalation factors, whether there has been an underspend in those operating expenditure categories
> - any other issues that are relevant.
>
> This information will be used to determine whether there has been underspending in an area that directly or in part impacts on the service standard benchmark against which Western Power has underperformed.

2118. The Authority agrees that the circumstances leading to failures to achieve service standard benchmarks will vary. The process proposed by Western Power is reasonable and likely to capture most aspects of any underperformance. The Authority considers this process should be included in the revised proposed revisions to the access arrangement. The Authority notes, in the event of any failure to meet service standard benchmarks, Western Power bears the onus of proof to demonstrate that any above-benchmark surplus has not arisen due to the failure to meet service standard benchmarks.

Required Amendment 34

Western Power must amend its revised proposed revisions to the access arrangement to include the process for how it will be determined and to what extent there is a relationship between costs savings and the underperformance on service standards as set out in Western Power's amended access arrangement information.

2119. As the Authority has not approved Western Power's proposed operating costs, the Efficiency and Innovation Benchmarks, as set out in Table 27 of the revised proposed revisions to the access arrangement, must be amended to be consistent with the Authority's determination of efficient operating costs.

Required Amendment 35

Western Power must amend Table 27 of the access arrangement to be consistent with the Authority's determination of efficient operating costs as set out in this Final Decision.

Service Standard Adjustment Mechanism

2120. Section 6.30 of the Access Code requires that an access arrangement include a service standards adjustment mechanism (**SSAM**). The SSAM is defined under section 6.29 as a mechanism in an access arrangement detailing how the service provider's performance during the access arrangement period – against the SSBs – is to be treated by the Authority at the next access arrangement review.

2121. Under the SSAM, an amount is added to, or deducted from, the target revenue for each of the transmission system and the distribution system for the next access arrangement period.

2122. Under the SSAM in the current access arrangement (clause 5.24A and 5.24B), each service standard for which there is a SSB has an accompanying specification of:

- a scheme of penalties and rewards for under-performing or out-performing against the targets established in the access arrangement;
- a target value, which is set equal to the SSB for each year of the second access arrangement period;
- a band around the target value – which is not relevant to the calculation of the reward or penalty for performance that varies from the target value, but which is shown to provide an indication of the expected performance;

- a cap on the 'revenue at risk' for the combined transmission service standards penalties – set at one per cent of maximum transmission revenue;[600] and
- no cap on the distribution network 'revenue at risk' during the current access arrangement.

2123. The current access arrangement transmission network SSAM measures relate to:

- Circuit Availability;
- System Minutes Interrupted (meshed network); and
- System Minutes Interrupted (radial network).

2124. The current access arrangement distribution network SSAM measures relate to:

- SAIDI – CBD (Minutes);
- SAIDI – Urban (Minutes);
- SAIDI – Rural short (Minutes);
- SAIDI – Rural long (Minutes);
- SAIDI – CBD (Events);
- SAIDI – Urban (Events);
- SAIDI – Rural short (Events); and
- SAIDI – Rural long (Events).

2125. The SSAM rewards or penalties are derived from the product of the 'service standard difference' (**SSD**) in each year, and the SSAM incentive rates. The SSD is the difference between actual performance on a measure and the target performance. The SSD in the current access arrangement is calculated as follows:[601]

$$SSD_{2009/10} = (SSB_{2009/10} – SSA_{2009/10})$$

$$SSD_{2010/11} = (SSB_{2010/11} – SSA_{2010/11}) - (SSB_{2009/10} – SSA_{2009/10})$$

$$SSD_{2011/12} = (SSB_{2011/12} – SSA_{2011/12}) - (SSB_{2010/11} – SSA_{2010/11})$$

Where:

SSD_t is the service standard difference in year t;

SSB_t is the service standard benchmark in year t; and

SSA_t is the actual service performance in year t.

2126. Western Power incentive rates for the transmission network SSAM for the current access arrangement are set out in Table 188.

600 Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 15 - 17.

601 Ibid.

2127. Western Power incentive rates for the distribution network SSAM for the current access arrangement period are set out in Table 189.

2128. Western Power proposed a 'transitional SSAM' to apply to:

- the SAIDI and SAIFI measures (with an additional exclusion in this case for these measures of the interruptions shown to be caused by a fault or other event on the transmission system); and
- the Circuit Availability measure.

2129. Western Power also proposed that:[602]

> The rewards and penalties are applied to the performance year in this access arrangement period (the rewards or penalties for the transitional SSAM SSBs are applied to the financial year ending 30 June 2013) and:
>
> - the reward or penalty for circuit availability will be allocated to the performance of the transmission system;
> - the reward or penalty for SAIDI and SAIFI will be allocated between the performance of the transmission system and distribution system in a fair and reasonable manner except for the reward or penalty for transitional SSAM SSBs which will be allocated to the performance of the distribution system;
> - the reward or penalty for call centre performance will be allocated to the performance of the distribution system.
>
> The rewards and penalties applied to each year as allocated to each of the transmission system and distribution system are summed for each of the transmission system and distribution system.

2130. Western Power further proposed that the sum of the rewards or penalties for the transmission system applied to each year is capped at 1 per cent of the Maximum Transmission Revenue for that year, and for the distribution system at 5 per cent of the Maximum Regulated Distribution Revenue for that year.[603]

602 Ibid.
603 Ibid.

Table 188 Transmission network SSAM incentive rates for the current access arrangement and proposed for AA3

	AA2 financial year 2010 – 2012	Revised access arrangement proposed AA3 – incentive rate financial year 2013 – 2017	Amended revised access arrangement proposed AA3 – incentive rate financial year 2013 – 2017
Circuit Availability ($ as at 30 June 2012 per 0.1 per cent)	-405,090	-712,798	-1,181,191 (reward side) -598,550 (penalty side)
System Minutes Interrupted (meshed network) ($ as at 30 June 2012 per system minute)	81,018		-
System Minutes Interrupted (radial network) ($ as at 30 June 2012 per system minute)	27,006		-

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 15 (with ERA conversion to $ million as at 30 June 2012); and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

Table 189 Distribution network SSAM incentive rates for the current access arrangement period and proposed for AA3

	AA2 financial year 2010 – 2012	Revised access arrangement proposed AA3 – incentive rate financial year 2013 – 2017	Amended revised access arrangement proposed AA3 – incentive rate financial year 2013 – 2017
SAIDI ($ as at 30 June 2012 per SAIDI minute)			
CBD	237,653	68,346	69,987 (reward and penalty side)
Urban	237,653	488,756	535,400 (reward and penalty side)
Rural short	8,858	199,256	219,734 (reward and penalty side)
Rural long	8,858	62,535	66,263 (reward and penalty side)
SAIFI ($ as at 30 June 2012 per 0.01 SAIFI event)			
CBD	111,265	76,911	68,895 (reward and penalty side)
Urban	111,265	431,779	519,575 (reward and penalty side)
Rural short	4,861	188,792	208,990 (reward and penalty side)
Rural long	4,861	87,798	96,599 (reward and penalty side)
Call centre performance ($ as at 30 June 2012 per 0.1 per cent)			
	-	-60,190	-54,246 (reward side) -32,781 (penalty side)

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 17 (with ERA conversion to $ million as at 30 June 2012); and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

Transmission network SSAM targets and incentive rates

2131. Western Power's proposed transmission network SSAM service standard targets (**SST**s) relating to the Circuit Availability measure were set from the 50 per cent Probability of Exceedence (**PoE**) levels. These PoE levels were derived from a best fit statistical analysis of the most recent five years of actual monthly performance data (refer to paragraph 1890 above for a more detailed description of Western Power's analytical method). The SSAM SSTs proposed by Western Power in September 2011 are set out at Table 177 above.

2132. Western Power proposed incentive rates for the transmission network SSAM for AA3 are set out in Table 188 above:

- The Circuit Availability total 'revenue at risk' was half of 1 per cent of the maximum transmission revenue. The incentive rate of $ per 0.1 per cent service standard difference (**SSD**) is the division of this total revenue at risk by the difference in per cent between the SSAM SST and the minimum standard SSB, multiplied by 0.1 per cent.

Distribution network SSAM targets and incentive rates

2133. Western Power's proposed distribution network SSAM SSTs were set from the 50 per cent PoE levels derived from a best fit statistical analysis of the most recent five years of actual monthly performance data (using a similar statistical approach as for setting the transmission SSBs – refer to paragraph 1890 above for a more detailed description of Western Power's analytical method). The resulting proposed SSAM SSTs are set out at Table 179, Table 180 and Table 181.

2134. Western Power proposed incentive rates for the distribution network SSAM for AA3 are set out in Table 189 above.

2135. The SAIDI and SAIFI incentive rates of $ per minute and $ per 0.01 event SSD are derived by.

- deriving a 'value of customer reliability' (**VCR**) for each of the Western Australian central business district, urban and rural customer classes – drawing on estimates from a study conducted for VENCorp in Victoria in 2008;
- apportioning the resulting VCR in $/kWh between the two types of events (around half to each type of event respectively);
- determining the average MWh demand/minute for each customer class (to inform the SAIDI incentive rate);
- determining the average MWh demand/event duration for each customer class (to inform the SAIFI incentive rate);
- combining the respective measures to give a $/minute (for SAIDI) and $/event (for SAIFI) incentive rate.

Summary of Submissions

2136. In addition to Western Power's September 2011 submission, the SSAM mechanism was addressed in submissions in 2011 from:

- Alinta;
- ERM Power;
- Perth Energy; and
- Western Australian Major Energy Users.

2137. These submissions were summarised and considered in the Draft Decision.

2138. A number of submissions on the Authority's Draft Decision, other than from Western Power, referred to the SSAM. The relevant points are included in the sections below.

Considerations of the Authority

2139. The Access Code does not provide guidance for the operation of a SSAM, other than the general requirements of section 6.31 for the mechanism to be:

- sufficiently detailed and complete to enable the Authority to apply the mechanism at the next access arrangement review; and
- consistent with the Code objective.

2140. In the context of the SSAM, consistency with the Code objective requires that the mechanism provides incentives for a service provider to incur costs efficiently to achieve, and potentially improve on, service standards benchmarks established for the access arrangement period, that provide equal or greater benefits to customers.[604] These costs may be of a capital nature, such as costs of replacing network assets subject to failure, or a non-capital nature, such as costs of undertaking preventative maintenance or employing additional work crews to restore supply more quickly when an outage occurs.

2141. The Authority has assessed the consistency of the proposed SSAM with the Code objective by giving attention to:

- the specification and operation of the proposed SSAM formula and the resultant incentives for actions to achieve and out-perform the proposed SSAM targets;
- the performance criteria proposed to be applied in determining the penalty and reward adjustments, particularly the proposed SSAM targets; and
- the value of incentive rates proposed to be applied in determining penalty and reward adjustments.

2142. These matters are addressed below.

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604 Efficiency here implies that Western Power should undertake expenditures to improve reference services only up to the point where the marginal costs of service improvement equal the marginal benefits of the service improvements to users of the network.

SSAM incentive formula

2143. Western Power's proposed revisions to the access arrangement (September 2011) proposed a change in the formula that calculates the annual SSAM reward or penalty for both the transmission and distribution networks.

2144. The existing second access arrangement SSAM service standard difference (**SSD**) was configured such that only an incremental improvement in net performance – compared to that in the year before – was rewarded. Under this approach, performance in any year could be above the SSAM target, but a penalty still apply, if the net difference between the actual services standard performance (**SSA**) and the service standard target (**SST**) is less than the year before. Conversely, performance may be below the target, but reward would still be received, provided that the net performance shortfall to the target was less than in the year before. The formula that applied in the current access arrangement for the second and subsequent years was:

$$SSD_t = (SST_t – SSA_t) - (SST_{t-1} – SSA_{t-1})$$

2145. The proposed method on the other hand aims to institute a simple difference in each year to calculate the SSD:

$$SSD_t = (SST – SSA_t)$$

2146. The Authority in its Draft Decision considered that neither the existing nor the proposed formula are ideal, suggesting that:

- the existing formula:
  - under-rewards Western Power for most of the access arrangement (**AA**) because the benefit of increasing the level of service is largely captured by consumers;
  - creates incentives to delay improvements in service to late in the AA;
- the proposed formula on the other hand:
  - over-rewards Western Power because the benefit of increasing the level of service is largely captured by it, at the expense of consumers;
  - creates incentives to undertake improvements early in the AA (or else to defer to the start of the next AA).

2147. The Authority considered two potential alternative formulas as a means to overcome the shortcomings of the above.

2148. The first alternative included an 'attenuation factor' (**AF**) in the existing formula that conditions the influence of the second difference term:

$$SSD_t = (SST_t – SSA_t) – \mathbf{AF} * (SST_{t-1} – SSA_{t-1})$$

2149. This is referred to as the ***factor*** approach.

2150. The second alternative took the proposed approach as the formula for the SSAM – but amended it to update the SST every year to incorporate the most recent 12 months of historic data (recalling that the SST is set on the basis of the most recent available 60 months of data). This is referred to as the ***ratchet*** approach.

2151. Analysis by the Authority for the Draft Decision suggested that the factor formula could be superior to the existing approach or to Western Power's proposed approach – in the sense that there is a more reasonable sharing of the benefits of higher levels of service between Western Power and its customers. In consequence, the Authority in its Draft Decision required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 51

Western Power should establish the SSAM formula as follows

$SSD_t = (SST_t - SSA_t) - AF^* (SST_{t-1} - SSA_{t-1})$ for the first and subsequent years of the AA

where:

SSD_t is the service standard difference in year t, and SST_{t-1} is the service standard difference in year t-1;

SST is the SSAM target;

SSA_t is the actual service performance in year t, and SSA_{t-1} is the actual service performance in year t-1, with respect to the SSAM measure;

AF is the 'attenuation factor' that takes the value 0.6.

2152. Western Power in its revised proposed revisions to the access arrangement (May 2012) does not accept the SSAM formula proposed by the Authority for the AA3 period, suggesting that:[605]

- the value likely to be delivered to customers is constrained to a level much less than the estimate of the value to customers of reliability (VCR)
- the Authority's reasoning is based on the incorrect assumption that Western Power will undertake inefficient investment that customers will be required to pay for.

2153. Western Power in the amended access arrangement information (May 2012) argues that its proposed formula should be adopted as:[606]

> The Authority's formula limits the financial incentive to Western Power to less than the value to customers of service performance. This reduces the incentive for Western Power to improve service, even though customers may place a higher value on service improvements.
>
> ...Western Power's proposed formula should be adopted as it is consistent with the formula used by the AER for electricity businesses in other jurisdictions. The AER's formula has been proven to achieve the appropriate balance between providing incentives for electricity businesses to pursue investment that delivers service

605 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 210.

606 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 211.

improvements to customers and ensuring customers pay no more than the estimated value to those customers of those improvements.

2154. Western Power's position hinges on the following points (the following order is not the same as Western Power's, but is intended to ease the flow of argument):

- investments in reliability that are not forecast prior to the regulatory period will not be recovered through the Investment Adjustment Mechanism (**IAM**), and hence will not enter the capital base until the next access arrangement;
- Western Power would not be over-rewarded in the event that capital expenditure was forecast for reliability improvements;
- forecast growth capital will not lead to net improvements in service standard outcomes;
- mathematical exposition which purports to prove that Western Power would not be over-remunerated under its proposed formula; and
- Western Power's proposed SSAM formula will lead to consistent incentives through the access arrangement period.

2155. Each of these points is addressed in what follows.

Investments in reliability and the IAM

2156. The Authority in the Draft Decision set out the results of modelling which supported its choice of the 'factor' formula.[607] That modelling assumed that Western Power would receive a return on and return of capital invested on an 'as incurred' basis.

2157. Western Power points out that this could only occur through the IAM. However, capital expenditure for the specific purpose of improving services levels and reliability are not eligible for the IAM.

2158. The Authority accepts this point.

Forecast capital expenditure for reliability improvements

2159. Another potential way in which capital expenditure for the specific purpose of improving services levels and reliability could be included in the capital base, as it was incurred, would be if it was included in the forecast of capital expenditure for the regulatory period.

2160. Western Power notes that if this was the case, then it would be expected that the SSAM SSTs for the forthcoming regulatory period would be adjusted such that the expectation was that Western Power would achieve the targets 50 per cent of the time.

2161. The Authority accepts that where capital expenditure for reliability improvements was forecast, then the SSAM SSTs would be reviewed to account for any expected improvement.

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607 Economic Regulation Authority 2012, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 309.

Forecast growth capital and improvements in service and reliability

2162. To the extent that growth capital leads to improvements in service and reliability, then there could be rewards from the SSAM in addition to the return on, and of, the growth capital on an as incurred basis (the latter would result from the growth capital being included in the capital base either through the ex ante forecast of capital expenditure, or through the IAM).

2163. Western Power asserts in this context:[608]

> While some growth-related and asset replacement capital works may result in localised improvements in service levels, service levels deteriorate as assets continue to age. Generally, without the work program, service levels would deteriorate due to asset age. Western Power has sought to balance these improvements and deteriorations across the network so that average service levels are maintained.

2164. The Authority considers that there is potential for net improvements to service and reliability from significant growth and asset replacement investments, which would lead to reward under the SSAM as well as return on, and of, capital on an as incurred basis. A case in point would be the Mid West Energy Project, which is likely to lead to reliability improvements and hence improvements in service standards across a major portion of the network. Investments in wood poles would be another class of investment which could potentially lead to significant improvements in some portions of the network.

2165. That said, the Authority recognises that it would be difficult to separate out these effects, so as to determine the overall net impacts.[609] On this basis, the Authority considers that it is reasonable to ignore this investment for the purposes of the SSAM, and hence to conclude that capital expenditure for the purposes of improving services levels and reliability that is not forecast prior to the regulatory period is only likely to be included in the capital base at the next reset.

Outcomes of modelling

2166. Western Power presents a mathematical exposition to indicate that it would not be over-rewarded under its proposed SSAM formula. The following extracts from the amended access arrangement information (May 2012) summarise Western Power's arguments (the Authority's comments are in italics):[610]

> 1) The net benefit to Western Power of a reliability improvement is the difference between the revenue received from customers (through the SSAM and if the capital expenditure is added to the capital base, through the return on and return of the capital investment) and the present value of the initial capital investment. That is: the present value of the amount paid by customers > the present value of the investment.
>
> *[in shorthand, this condition may be written as C > X, where:*

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608 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 214.

609 In the case of the Mid West Energy Project, an explicit net present value was placed on reliability improvements under the New Investment Facilities Investment Test process. However, this would be just one element in any required calculation of net impacts on service standards and reliability.

610 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 211 - 213.

C = the present value of the amount paid by customers; and

X = the present value of the investment]

2) As the investment may not be added to the capital base and the return on and return of the asset could be zero, Western Power will not seek to undertake investments unless it delivers at least the value available under the financial incentive scheme.

3) The financial incentive Western Power receives reflects the value of the service *outcome* to customers. Undertaking the investment alone is not enough to ensure the receipt of the benefit under the financial incentive scheme - the service improvement must also be delivered. Any investment will be subject to a risk assessment that the service outcome will be delivered, increasing the hurdle rate for going ahead with any investment. Therefore, all investment that results in a financial benefit will be at a cost less than the financial incentive received.

4) The capital investment will only meet the net benefits test if the present value of the reliability improvements exceeds the present value of the initial capital investment.

[in shorthand, this condition may be written as B > X, where:

B = the present value of the reliability benefits to customers; and

X = the present value of the investment]

5) [Point 1) and point 4) together] implies that the present value of the amount paid by consumers to Western Power must always be less than the present value of the reliability improvements. If not, the net benefits limb of NFIT [New Facilities Investment Test] would not be met, the capital investment could not be added to the capital base, the revenue earned by Western Power would decrease and the investment would be less commercially viable. Therefore, customers will never pay more for reliability improvements than they value the reliability improvements.

[in shorthand, this assertion may be written as C < B, since:

from 1) C > X; and

from 4) B > X;

however, the Authority does not view this as a mathematical proof, as C < B, or equally C > B, while still meeting the condition in 1) and 4) that both are greater than X]

6) The cost to customers during the access arrangement period is limited to the financial incentive payment. The cost to customers in subsequent access arrangement periods is limited to the regulated return on and of the investment for the life of the investment, assuming that the capital expenditure is added to the capital base and any carryover benefits from the financial incentive Western Power receives no further additional financial incentive in subsequent access arrangement periods despite the service improvement benefit to customers of that investment continuing for the life of that investment.

2167. Finally, Western Power also states that it would not undertake an investment where the forecast costs are more than the expected financial benefit, asserting that.

- There are no examples where Western Power could make service standard improvements at zero or low cost.
- Western Power would not invest up to the value to customers, due to the risks associated with the investment [see points 2) and 3) above].

2168. The Authority considers each of the points made by Western Power in what follows.

2169. The Authority accepts the first point, given that Western Power would be unlikely to proceed with an investment that delivered a net loss.[611]

2170. The second point states that Western Power would only invest up to the value of the SSAM incentive payments. This implies than none of the investment would be included in the capital base. The Authority notes that this appears to be at odds with point 5). The Authority considers that Western Power should ensure that its investments are efficient, and hence would pass the New Facilities Investment Test (**NFIT**). The Authority notes in this context that Western Power should be able to assess the reliability and service standards of its networks, and the returns to investment in the same.[612] The Authority also notes that investments in reliability may be included for consideration in the NFIT. Together, these elements should assist any case for efficient capital expenditures associated with reliability and service improvement under the NFIT.

2171. The Authority accepts the third point, although again, similar to the arguments made in the previous paragraph, considers that any discount to service level outcomes should be limited if Western Power undertakes an appropriate assessment of the business case.

2172. The Authority accepts the fourth point. This is not to say that the present value of the reliability benefits *must* be greater than the present value of the investment, simply that any portion that is assessed to not meet the NFIT could be excluded from the capital base.

2173. The Authority does not accept the assertion of the fifth point, for the reason of the italicised comments in paragraph 2166 at sub-points 1), 4) and 5).

2174. The Authority also does not accept the sixth point. As noted above, the Authority considers that Western Power has not accounted in 1) for the potential for there to be additional payments under the SSAM in the second regulatory period (see the points made at paragraph 2168). As a result, it is not true to state that ‘the cost to customers in subsequent access arrangement periods is limited to the regulated return on and of the investment for the life of the investment’. Any consideration of the cost to customers must take account of this potential for additional payment under the SSAM.

2175. Finally, the Authority considers that Western Power has misconstrued the examples set out in the Draft Decision. These are intended to illustrate the polar extremes, so as to help inform the assessment. While the Authority accepts that the opportunity

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611 However, the Authority notes that the formula presented by Western Power that is associated with the first point (labelled 1 on page 211 in Western Power’s amended access arrangement information) is correct for a capital expenditure made in the early years of an access arrangement, but fails to take into account payments under the SSAM that may occur in the following regulatory period, for a capital expenditure made in the latter years of a regulatory period. For example, where three years of most recent historic data are used to set the SSAM SST, then a capital expenditure made in the final year of a regulatory period would result in the SST only being adjusted by either one third or one fifth (for SSTs based on three years of historic data or five years, respectively), with the result that there would be SSAM rewards over the whole of the second regulatory period.

612 Stochastic events may lead to year to year variation in service standards performance. The Authority recognises that this creates risk for Western Power with regard to any investments in service standard performance improvement. That said, the SSAM incentive payments generally over-reward Western Power for investments in performance improvement, providing a margin for error.

for zero or low cost actions may be limited, this does not mean that 'no regrets' or low cost actions with significant rewards are not possible, or even available.

2176. Overall, the Authority considers that Western Power's exposition does not address the merits of the various proposed SSAM formulae set out at paragraphs 2144 to 2150 above. In this context, the Authority notes that Western Power's mathematical formulation of the present value of the amount paid by customers is incorrect. Furthermore, the net present value of the amount paid by customers under the various alternative SSAM formulas has not been estimated, nor has this amount been compared to the net present value of the value of customer reliability improvements.

2177. The Authority has modelled these various outcomes, albeit in a spreadsheet model rather than through mathematical reasoning (see **Appendix 5** for detail). The modelling is similar to that adopted for the Draft Decision, but amended to:

- recognise that capital investments in service standard improvement will only be included in the capital base at the next regulatory period;
- adopt a central customer discount rate of 8 per cent, consistent with the Productivity Commissions recommendations for cost benefit analysis (higher rates were assessed as a sensitivity).[613]

2178. This modelling – which takes into account the potential for SSAM payments to occur in the second subsequent regulatory period (for investments made later in the initial regulatory period) – recognises that the differences between Western Power's proposed formula and the factor formula depend on the size of the factor.

2179. The Authority acknowledges that its analysis does not take into account all of the risks that Western Power needs to consider when undertaking a project to improve service standards. These include that the project may not perform as expected in terms of delivering service standards, or that rewards may be delayed due to natural variation in year to year performance.

2180. The modelling suggests that Western Power's proposed formula is similar in outcome to an optimally configured factor formula.[614] The Authority has therefore concluded that Western Power's proposed formula provides reasonable incentives for Western Power to undertake projects to improve services, while retaining an acceptable proportion of the benefits for customers.

2181. The Authority therefore considers that, on balance, Western Power's proposed formula is acceptable.

[613] See for example, Productivity Commission 2010, *Valuing the Future: the social discount rate in cost-benefit analysis*, www.pc.gov.au, p. 62.

[614] It is worth noting that Western Power's proposed formula equates to the factor formula, where the factor is set to zero (0). An optimal factor for the factor formula is around 0.1 at an 8 per cent discount rate, and lower at higher discount rates. This suggests that the optimal factor is between 0 and 0.1.

Transmission network SSAM

SSAM target measures

2182. Western Power proposed that the SSAM for transmission networks in AA3 only apply in respect of the Circuit Availability measure.

2183. Western Power proposed to discontinue the SSAM incentives in relation to the System Minutes Interrupted (meshed network) and System Minutes Interrupted (radial network) measures, in line with its proposal to remove these measures as SSBs. Western Power's rationale for discontinuing these as SSBs and as SSAM measures, is as follows:[615]

> These are measures of the performance of the transmission network rather than the reference service received by transmission-connected customers. The definition of service standard benchmarks relating to network performance (rather than reference services) is not consistent with the requirement of section 5.1 of the Access Code to specify a service standard benchmark for each reference service.

2184. As noted at paragraphs 1903 to 1916 above, the Authority does not consider that these reasons justify the omission of the System Minutes Interrupted measures as service standards. The Authority considers that these two measures, absent effective alternatives, provide information on the transmission reference tariff service performance. The information provided by the measure for radial networks is particularly important, as these networks have no redundancy.

2185. The Authority required in the Draft Decision that a number of other transmission measures be included in the SSAM – namely the System Minutes Interrupted measures (0.1 to 1 minute, and greater than 1 minute), and Average Outage Duration measure. Western Power rejected these requirements in its revised proposed revisions to the access arrangement (May 2012).

2186. The Authority considers Western Power's position with regard to each of the foregoing transmission measure categories in what follows.

Circuit Availability

2187. Western Power proposed that the SSAM service standard target (**SST**) target for Circuit Availability in AA3 should be set at a lower standard (97.7 per cent) than that applying in the current access arrangement (98.0 per cent). Western Power stated that this expected level of performance should be achievable 50 per cent of the time, as it is informed by the average actual performance over the last five years.

2188. The Authority noted in the Draft Decision that the 97.7 per cent level is derived as the Weibull distribution 50 per cent PoE level for the last five years of monthly data (98.2 per cent availability), less a 0.5 per cent reduction to account for the proposed increased level of capital works during the AA3 period.

2189. As noted at paragraph 1895 above, the Authority considered that a 0.5 per cent reduction is not justified, but rather only a 0.2 per cent reduction below the historic performance parameters is warranted, taking account of the increased capital

[615] Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 90.

works anticipated during AA3. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 52

The Circuit Availability target must be set at 98.0 per cent. This is the 50 per cent probability of exceedence level derived from the application of a Weibull distribution to the last five years of historic data, but with a reduction of 0.2 per cent included.

2190. In its revised proposed revisions to the access arrangement (May 2012) Western Power accepted this required amendment.

2191. The foregoing analysis was based on 5 years of historic data through to 2010-11. More recent 2011/12 data for Circuit Availability performance has now been provided by Western Power. Accordingly, the Authority has updated the estimates for the Circuit Availability benchmark. The revised 50 per cent PoE level is 98.3 per cent (see Appendix **3** for detail). Reducing this by 0.2 per cent gives an SST for Circuit Availability of 98.1 per cent.[616]

Required Amendment 36

The Circuit Availability SST should be set at 98.1 per cent. This is the estimated 50 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.

System Minutes Interrupted

2192. In its Draft Decision, the Authority required that Western Power retain the System Minutes Interrupted (meshed and radial networks) as SSAM measures.

2193. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 53

The System Minutes interrupted (meshed and radial networks) measures must be retained as a SSAM incentive measure. The SSAM SST for this measure should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data.

616 Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to Appendix **4** for further detail).

2194. Western Power rejected this requirement in its revised proposed revisions to the access arrangement (May 2012). Western Power considers that:

- network-based measures are not required under the Access Code, whereas reference service measures are;
- transmission network measures provide little information to transmission reference service customers;
- transmission performance will be included with the distribution network performance measures;
- the measures are statistically unsound;
- the measures are not independent of other transmission network measures that the Authority is proposing to include in the SSAM;
- the proposed reference service measures will ensure that reliability improvements are targeted where it is economically efficient, rather than inefficiently biasing investment to improving reliability of radial networks.

2195. As noted at paragraphs 1903 to 1906 above, the Authority considers that the transmission network service outcome is a key component for the performance of all reference services, including for transmission reference services for large customers connected to the transmission network.

2196. Given this, the Authority does not consider that network based measures are not required under the Access Code, or that these provide little information to transmission reference service customers. While the Authority accepts that there is not a direct one for one relationship between the network performance and the individual customer's reference tariff service level, the Authority nevertheless considers that the network based measures provide a reasonable proxy for the transmission reference tariff service levels. The Authority notes that the radial networks measure provides unique information that is not provided by the other transmission network measures. The Authority therefore does not consider that Western Power has made a case for dropping these measures as a minimum standard SSB.

2197. The Authority considers that retaining the transmission network measures is preferred to rolling in transmission performance to the distribution performance measures, as it allows the attribution of performance to the separate networks to be observed. Rolling transmission performance into the distribution network measures does not provide information for transmission connected customers, whether these customers be large generation or load connections.

2198. The issue of statistical soundness of the System Minutes Interrupted measures was considered in paragraphs 1909 to 1916 above. The Authority considered that in the absence of alternatives, the measure should be retained – although noted that it may be desirable to begin collecting data to allow an eventual move away from this measure.[617]

[617] The Authority has noted the potential overlap with other transmission measures, and suggested at paragraph **1914** that Western Power consider collecting disaggregated data for meshed and radial networks for Loss of Supply Event Frequency and Average Outage Duration for meshed and radial networks, so as to allow this measure to be discontinued.

2199. However, recognising Western Power's fifth point above (under paragraph 2194), the Authority considers that the System Minutes Interrupted (meshed networks) measure could assume less importance as a SSAM incentive measure, provided that alternative measures could be substituted.[618] In this context, the Authority considers that the Loss of Supply Event Frequency and Average Outage Duration measures together provide equivalent information *for the meshed network*. As the Authority is proposing to include these measures in the SSAM (see below), it is prepared to accept discontinuing the System Minutes Interrupted (meshed networks) measure in the SSAM.

2200. That said, the Authority considers that it remains important to ensure that the maintenance of service levels for the radial networks are not neglected. This is particularly the case given the apparent recent deterioration in performance on this measure, and also the recognised need for the wood pole replacement program.[619] On this basis, the Authority considers that the System Minutes Interrupted (radial networks) measure be retained in the SSAM for AA3.

2201. The Authority has received updated historic performance data from Western Power that includes the most recent 2011/12 performance data. Accordingly, the Authority has updated its estimates of the transmission SSTs for the third access arrangement (Table 184 – see Appendix **3** for detail).[620]

Required Amendment 37

The System Minutes interrupted (radial networks) measure must be retained as a SSAM incentive measure. The SSAM SST for this measure should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see **Table 184** for the Authority's estimates).

Loss of Supply Event Frequency and Average Outage Duration

2202. The Authority in the Draft Decision gave consideration to requiring that unplanned Loss of Supply Event Frequency and Average Outage Duration measures be introduced as SSAM incentive measures.[621]

2203. The Australian Energy Regulator's transmission network Service Target Performance Incentive Scheme includes these incentive measures.[622] The Authority noted in the Draft Decision that performance of Western Power would

618 Circuit availability reflects the proportion of available time that the network elements are available. System minutes interrupted is a measure of the amount of time in minutes that meshed and radial circuit elements are not available.

619 See footnote **571** in the SSB section which refers.

620 Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to Appendix 4 for further detail).

621 Circuit availability reflects the proportion of available time that the network elements are available. System minutes interrupted is a measure of the amount of time in minutes that meshed and radial circuit elements are not available.

622 Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 43.

appear to be inferior compared to other transmission network service providers elsewhere in Australia – for example loss of supply events have averaged around 26 events per annum for Western Power, whereas comparable total reported loss of supply events from other jurisdictions averaged 8 events for a sample of network service providers in 2010 (Table 190).[623]

2204. The Authority accordingly required the following amendments to the proposed revised access arrangement.

Draft Decision Amendment 54

The Loss of Supply Event Frequency measures must be retained and included as SSAM incentive measures. The SSAM SSTs should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data.

Draft Decision Amendment 55

The Average Outage Duration measure must be retained as SSAM incentive measures. The SSAM SST must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data.

2205. Western Power rejected these requirements in its revised proposed revisions to the access arrangement (May 2012). Western Power considers that:

- network-based measures are not required under the Access Code, whereas reference service measures are;
- transmission network measures provide little information to transmission reference service customers, as their experience is significantly better than the average network performance on this measure;
- transmission performance will be included with the distribution network performance measures, and will allow improvements to be targeted where these are economically efficient;
- Western Power would continue to monitor and report Loss of Supply Event Frequency to enable stakeholders to compare performance with other transmission networks if required.

2206. The Authority notes that these points are the same as those made for the System Minutes Interrupted measures, and considers that the same responses apply (see paragraphs 2195 to 2199 above).

623 The Authority considers that while the comparison requires approximation, given the different 'collars' on the measures in each jurisdiction, as the Western Power collar is 0.1 events, and as the collars in Table 213 are very similar, then the fact that Western Power's average is significantly higher shows a lower level of performance overall.

Table 190 Transmission incentive measure weightings and 2010 performance for selected National Electricity Market transmission networks

Parameter	Weighting (MAR %)	2010 performance (with exclusions, by relevant unit)
TransGrid		
Circuit availability – transmission line availability	0.20	98.8%
Circuit availability – transformer availability	0.15	98.4%
Circuit availability – reactive plant availability	0.10	95.4%
Loss of supply event frequency > 0.05 (x) system minutes	0.25	3 events
Loss of supply event frequency > 0.25 (y) system minutes	0.10	1 event
Average outage duration – total	0.20	861 minutes
Powerlink		
Circuit availability – critical	0.15	98.7%
Circuit availability – non-critical elements	0.085	98.8%
Circuit availability – peak hours	0.15	98.6%
Loss of supply > 0.2 system minutes	0.15	0 events
Loss of supply > 1.0 system minutes	0.30	0 events
Average outage duration	0.15	779 minutes
ElectraNet		
Circuit availability – total transmission	0.30	99.7%
Circuit availability – critical circuit peak	0.20	99.7%
Circuit availability – critical circuit non-peak	0.0	99.5%
Loss of supply event frequency > 0.05 (x) system minutes	0.10	11 events
Loss of supply event frequency > 0.2 (y) system minutes	0.20	6 events
Average outage duration – total	0.20	130 minutes
Transend		
Transmission circuit availability – critical	0.2	99.5%
Transmission circuit availability – non-critical	0.1	99.4%
Transformer circuit availability	0.15	99.1%
Loss of supply event frequency > 0.01 system minutes	-	9 events
Loss of supply event frequency > 1.0 system minutes	-	2 events
Average outage duration – transmission lines	-	275 minutes

Source: Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 43; Australian Energy Regulator 2011, *Service standard compliance report 2010*, www.aer.gov.au, various network service provider reports.

2207. The Authority further notes that its technical advisor, GBA, considers that: [624]

> The transmission network is an important part of Western Power's asset base and comprises 40% of fixed assets by value. It is also the network into which the majority of the electricity delivered to consumers is injected.
>
> ...the number of interruptions and average interruption duration performance measures relate directly to the performance of the transmission network and in particular how this performance impacts directly connected customers... these performance indicators should be retained... these indicators could also be included in the SSAM.

2208. The Authority agrees with GBA and considers that these performance indicators should be retained and adopted as SSAM measures.

2209. The Authority notes that these measures together provide a substitute for the System Minutes Interrupted (meshed networks) measures, allowing that measure to be discontinued under the SSAM.

2210. The Authority has received updated historic performance data from Western Power that includes the most recent 2011-12 performance data. Accordingly, the Authority has updated its estimates of the transmission SSBs and SSTs for the third access arrangement (Table 184 – see Appendix 3 for detail).[625]

Required Amendment 38

The Loss of Supply Event Frequency (0.1 to 1 system minutes and greater than 1 system minutes) and the Average Outage Duration measures must be included as SSAM incentive measures. The SSAM SSTs must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see **Table 184** for the Authority's estimates).

Transmission incentive rate and weightings

2211. The Authority observed in the Draft Decision that Western Power had estimated an incentive rate for the transmission network which places 0.5 per cent of the average annual maximum transmission revenue forecast for AA3 at risk.[626] Conversely, Western Power would realise this amount as a reward if its performance exceeded the proposed Circuit Availability SST. The Authority noted in the Draft Decision that

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[624] Geoff Brown and Associates 2012, Technical Report, www.erawa.com.au, p. 37 and 45.

[625] Western Power considers that inclusion of the 2011/12 data renders the estimates inconsistent with current service performance. The Authority does not consider that this argument is substantiated (refer to Appendix **4** for further detail).

[626] This estimate is contained in a spreadsheet provided to the Authority, with the resulting values set out in the proposed access arrangement (see the tables at Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42).

this appeared to be at odds with Western Power's clauses in the proposed access arrangement that:[627]

> 7.5.9 Notwithstanding section 7.5.8 of this *access arrangement*, the sum of the rewards or penalties for the *transmission system* applied to each year is capped at 1% of TR_t for that year as defined in section 5.6.6.

2212. The Authority also noted in the Draft Decision that Western Power had developed its incentive rate by applying the amount of revenue at risk to the units of difference between the PoE 50 per cent SST and the PoE 97.5 (minimum standard) SSB. The Authority did not have a problem with this general approach. However, the Authority noted that most of the best fit statistical distributions applied to setting the SSB and SST – such as the Weibull distribution – are not symmetric. In these cases, the Authority considered that Western Power should apply separate incentive penalty and reward rates so as to evenly span the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively. The reward rates and penalty rates in this case will be asymmetric, with 1 per cent revenue at risk and 1 per cent of revenue available as a reward.

2213. The Authority observed in the Draft Decision that Western Power had not proposed any weightings in its SSAM proposal, as it had only proposed the Circuit Availability measure. However, the Authority considered that with the SSAM encompassing a broader range of measures, that a weighting system be developed similar to the Australian Energy Regulator's Service Target Performance Improvement Scheme.

2214. The Authority accordingly required the following amendments to the proposed revised access arrangement.

[627] Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

Draft Decision Amendment 56

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue, taking account of the revisions to allowable transmission revenue set out in this draft decision;

- apply separate incentive penalty and reward rates where non-normal distributions are applied, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively;

- adopt the weightings set out in the Draft Decision to allocate the revenue at risk across the various measures.

Revenue at risk

2215. Western Power noted in its amended access arrangement information (May 2012) that the average annual maximum transmission revenue at risk was set to 0.5 per cent because the other 0.5 per cent of transmission revenue at risk was to be allocated to SAIDI and SAIFI performance, under its proposal to include transmission performance in those measures.

2216. The Authority accepts Western Power's explanation. However, the Authority considers that as it is requiring that the transmission performance SSAM be kept separate from distribution performance SSAM, the proposed amounts should be increased to 1 per cent of transmission revenue. In calculating this amount, Western Power will need to take account of the revisions to allowable transmission revenue set out in this Final Decision.

Separate incentive penalty and reward rates

2217. Western Power in its amended proposed revisions to the access arrangement (May 2012) accepted the Authority's requirement that separate incentive penalty and reward rates be utilised where non-normal distributions are applied.

Weightings

2218. In the Draft Decision, the Authority required that Western Power adopt weightings to allocate the revenue at risk across the various measures, informed by the following comments by the Australian Energy Regulator:[628]

> The Australian Energy Regulator has accepted weightings that placed half of the revenue at risk for parameters related to 'security of supply' (i.e. circuit availability) and allocated the remainder equally to parameters related to 'reliability of supply' (i.e. loss of supply) and 'operational response' (i.e. duration of an outage). The Australian

628 Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 28 and p. 30.

> Energy Regulator considered this weighting structure to be consistent with the services more highly valued by customers and the objectives of the STPIS.
>
> ...it has been argued that with the aggregate incentive under the scheme set at one per cent of revenue, a parameter specific weighting of less than 10 per cent of the total revenue at risk is too weak to provide an incentive for a TNSP to maintain or improve service performance.

2219. Western Power did not accept the Authority's weightings for the SSAM measures – to derive the overall SSAM performance – as set out in the Draft Decision. Western Power states:[629]

> If the Authority determines that transmission network performance measures should be included in the SSAM, then the transmission revenue at risk weightings would need to be allocated across circuit availability, loss of supply event frequency and average outage duration and further consultation between Western Power and the Authority would need to occur to agree the appropriate weightings.

2220. The Authority considers that it remains valid to follow the broad approach set out by the Australian Energy Regulator. However, given that the Authority now accepts that the System Minutes Interrupted (meshed networks) is not required as a SSAM measure, there is a need to amend the weightings that were set out in the Draft Decision.

2221. The Authority considers that Circuit Availability should still have a weighting of 0.5, with the other 0.5 split between the other measures. The Authority also considers that the System Minutes Interrupted (radial networks) should have a minimum weighting of 0.1, so as to not overpower this measure.[630] That leaves 0.4 to be allocated among the remaining measures. The Authority has allocated a 0.2 weighting to Average Outage Duration and 0.1 to each of the Loss of Supply Event Frequency measures (see Table 191).

2222. Western Power requests that if the additional transmission network measures are included, then the weightings need to be 'negotiated'. However, the Authority notes that there is no process for negotiating. The Authority has stipulated the weights. Western Power can either accept these or change these in its response. If the Authority considers that Western Power's proposed alternatives are unsatisfactory, then it has the option to reject Western Power's proposal and to impose its own set of weightings based on its judgment of what better meets the Code objective.

2223. The Authority notes that with these weightings summing to one (1), the maximum revenue at risk would be 1 per cent of the maximum transmission revenue, and the maximum reward 1 per cent of the maximum transmission revenue.

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629 Western Power 2012, *Amended access arrangement information for the Western Power Network*, www.erawa.com.au, p. 228.

630 Setting the weighting at the minimum 10 per cent recognises that radial networks are a reasonably small proportion of the overall network. Setting the importance to the minimum feasible of 10 per cent will help to ensure that there is a reasonable incentive to maintain performance, while minimising the risk of uneconomic investment.

Required Amendment 39

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue;
- adopt the weightings set out in Table 4 to allocate the revenue at risk across the various measures
- take account of the revisions to allowable transmission revenue set out in this Final Decision to calculate the reward and incentive penalty rates.

Table 191 Transmission network SSAM SST and incentive weightings for AA3

	SSAM SST	Weighting
Circuit Availability ($ per 0.1%)	98.1%	0.5
Loss of Supply Event Frequency (0.1 to 1 minute) ($ per event)	24 events	0.1
Loss of Supply Event Frequency (0.1 to 1 minute) ($ per event)	2 events	0.1
Average Outage Duration ($ per minute)	886 minutes	0.2
System Minutes Interrupted (radial networks) ($ per minute)	1.9 minutes	0.1

Source: Authority analysis

Distribution network SSAM

2224. Western Power proposes to retain the SAIDI, SAIFI measures in the SSAM, and to introduce a new Call centre performance measure.

SAIDI and SAIFI

2225. The Authority in the Draft Decision considered that rewarding or penalising performance against the SAIDI and SAIFI measure targets can provide an appropriate incentive for Western Power to maintain or improve performance on the network. The Authority thus accepted these measures for inclusion in the SSAM.

2226. However, the Authority did not consider, on balance, that amendment of the SAIDI and SAIFI measures to include transmission network events was justified (see above).

2227. The Authority therefore required that the SSAM SAIDI and SSAM SAIFI targets be reconfigured to apply to distribution networks only.

2228. Western Power estimated the SAIDI and SAIDI SSTs based on the 50 per cent PoE analyses of the best fit distribution to the most recent five years (60 months of rolling 12 monthly observations) of performance data that included both transmission and distribution network events (refer Table 179 and Table 180).

2229. In the Draft Decision the Authority considered that the method proposed for setting distribution network SSTs was acceptable and would provide appropriate reward or penalty for performance. However, in line with the discussion at paragraph 1933 to 1934, the Authority considered that these distribution network SSTs should be set on the basis of the most recent three years of historic data, as Western Power had undertaken explicit investment to improve SAIDI and SAIFI performance during AA2:

Draft Decision Amendment 57

Western Power must:

- adopt revised estimates that remove the transmission network events from the SAIDI and SAIFI measures;
- base the targets on the most recent three years of data.

2230. Western Power in amended proposed revisions to the access arrangement accepted that the targets should be based on the most recent three years of data, but rejected the recommendation that transmission network events be removed from the SAIDI and SAIFI events.

2231. However, as set out above in the transmission section, the Authority does not consider that transmission performance should be rolled into the distribution measures. Accordingly, the Authority requires that the distribution network SSAM SSTs be based on the most recent three years of 'distribution only' data.

Required Amendment 40

Western Power must adopt revised SAIDI and SAIFI SSAM SSTs that remove the transmission network events from the estimates. The SSAM SSTs must be set at the 50 per cent PoE level based on the best fit statistical distribution applied to the most recent three years of historic data (see Table 185 for the Authority's estimates).

Call centre performance

2232. Western Power also proposed to include a new Call Centre Performance measure as a SSAM measure. The Authority considered that there is merit in this measure, even though it is a process performance measure. The Authority notes that a telephone answering performance measure is a feature of the Australian Energy Regulator's Service Target Performance Incentive Scheme. The Authority accepted the inclusion of this measure as defined in the distribution network SSAM.

Distribution SSAM incentive rates

2233. Western Power's proposed incentive rates for the distribution network SSAM for AA3 are set out in Table 189.

2234. As noted at paragraph 2135, the SAIDI and SAIFI incentive rates of $ per minute and $ per event SSD are derived by.

- developing a 'value of customer reliability' (**VCR**) for each of the Western Australian central business district, urban and rural customer classes – drawing on estimates from a study conducted for VENCorp in Victoria in 2008;
- apportioning the resulting VCR in $/kWh between the two types of events (around half to each type of event respectively);
- determining the average MWh demand/minute for each customer class (to inform the SAIDI incentive rate);
- determining the average MWh demand/event duration for each customer class (to inform the SAIFI incentive rate);
- combining the respective measures to give a $/minute (for SAIDI) and $/event (for SAIFI) incentive rate.

2235. The Authority in the Draft Decision required:

Draft Decision Amendment 59

Western Power must:

- amend the SAIFI incentive rate to be '$ per 0.01 SAIFI event away from the SST'; and
- retain the proposed SAIDI incentive rate as being '$ per SAIDI minute away from the SST'.

2236. Western Power accepted these amendments.

2237. WAMEU noted in its submission on Western Power's original proposed revisions:[631]

> The Western Power proposal includes an approach to developing a cost impact relationship between SAIDI and SAIFI. Western Power uses the VENCorp concept and calculations of Value of Customer Reliability (VCR) to generate this relationship and uses a value of VCR of $62,256/MWh as the appropriate value for the SWIN. The WAMEU is very concerned at the magnitude of this value and its associate Major Energy Users (MEU) has raised similar concerns directly with AEMO. The

[631] WAMEU 2011, Submission, www.erawa.com.au, p. 87.

> MEU points to the way the AEMO assessed value of VCR has increased in real terms over the past decade whereas similar values used overseas are much lower and have varied little with time. This raises the concern that the AEMO developed VCR maybe considerably overstated. The ERA is requested to assess VCR in its own right and examine stakeholder views on this issue.

2238. The Authority in the Draft Decision noted that the Australian Energy Market Operator (**AEMO**) recently reviewed this issue. A report by Oakley Greenwood provided updated estimates of VCRs by customer type and by State, and includes corrections to the Victorian estimates.[632] The same report provides recommendations on escalation approaches. As a result the Authority required:

> **Draft Decision Amendment 58**
>
> Western Power must update its estimates of the Value of Customer Reliability to account for the findings of the Oakley Greenwood report – in particular to take account of the revised value of customer reliability estimates and the escalation method.

2239. Western Power accepted this amendment.

2240. Aside from that, the Authority accepted that Western Power's proposed approach is consistent with the Code objectives.

2241. The Authority in the Draft Decision noted that the incentive rates for the distribution network SSAM measures are derived independently of statistical distributions used to set the 'minimum standard' SSB and the SST. Hence, there is no issue in relation to an asymmetric penalty or reward rate.

2242. The Authority also noted in the Draft Decision that clause 7.5.10 of the proposed AA3 states:[633]

> 7.5.10 Notwithstanding section 7.5.8 of this *access arrangement*, the sum of the rewards or penalties for the *distribution system* applied to each year is capped at 5% of DR_t for that year as defined in section 5.7.6.

2243. For the removal doubt, the Authority noted that clause 7.5.10 implies that 5 per cent of distribution revenue is at risk, and that the total financial incentive (once the potential 5 per cent reward is accounted for) falls within a range of (plus or minus 5 per cent equals) 10 per cent of the distribution revenue. The Authority notes that this is consistent with the Australian Energy Regulator's distribution network Service Target Performance Incentive Scheme, which also provides for the sum of the incentives to lie between plus 5 per cent (the upper limit) and minus 5 per cent (the lower limit).[634]

2244. Western Power's proposed incentive rate for Call Centre Performance was originally set at $60,190 for every 0.1 per cent variation in performance.

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632 Oakley Greenwood 2011, *Valuing Reliability in the National Electricity Market: Final Report*, www.aemo.com.au, p. 32.

633 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

634 Australian Energy Regulator 2009, *Electricity distribution network service providers Service target performance incentive scheme*, www.aer.gov.au, p. 11.

2245. The Authority notes that this rate is calculated as 0.04 per cent of total distribution revenue for each 1 per cent variation in performance, which is consistent with the approach taken by the Australian Energy Regulator in its Service Target Performance Incentive Scheme. The Authority required that Western Power adjust the incentive rate to reflect the changes to total distribution revenue set out in this Final Decision.

2246. The Authority noted in the Draft Decision that the distribution applied to Call Centre Performance for the purposes of establishing the SSB and SST is a Weibull distribution, which is not symmetric around the SST. The Authority observed that assymmetric rewards and penalty rates would improve the allocation of incentives.

2247. The Authority thus required in the Draft Decision that:

Draft Decision Amendment 60

Western Power must:

- adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Draft Decision;
- apply separate incentive penalty and reward rates to the Call Centre Performance incentive, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively.

2248. Western Power accepted that separate incentive penalty and reward rates apply to the Call Centre Performance incentives. However, Western Power updated the rates for the distribution revenue to apply in its amended proposed revisions, which is not the same as that approved in this Final Decision. Accordingly, the Authority requires that this be amended to take account of the Final Decision determination on distribution network revenue.

Required Amendment 41

Western Power must adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Final Decision.

The "D factor" scheme

2249. The D-factor mechanism provides for the recovery in the next access arrangement period of operating expenditure that is incurred by Western Power as a result of deferring a capital expenditure project or in relation to demand-management initiatives.

2250. Western Power proposed retaining the D-factor in its current format but proposed that claims for deferred expenditure should only be made in relation to projects included in the D-factor Project List (provided to the Authority as confidential material) or the Transmission Network Development Plan. The current access arrangement requires that any expenditure claimed to have been deferred must have been included in Western Power's forecast capital expenditure in its revised access arrangement information or supporting documentation and in the Authority's allowed capital expenditure for the access arrangement period.

2251. Western Power considered the proposed revision would ensure there is documented evidence of any planned or potential capital investment that may be deferred by demand management or alternative options to network augmentation. Western Power noted that the D-factor Project List and the Transmission Network Development Plan included capital projects that are not certain enough to have been included in the third access arrangement expenditure forecasts at the time of their preparation. Western Power considered that linking the D-factor to these lists helps remove the bias towards capital investment solutions created by the investment adjustment mechanism.

2252. In its submission to the first round of public consultation, Synergy considered that D-factor projects and any associated funding should be treated no differently to any other new facility to enable Western Power to provide covered services. Synergy has also queried whether the D factor scheme is an adjustment that is allowed under the Access Code.

2253. The D-factor scheme was introduced in the second access arrangement review. Questions were raised at that time as to whether such a scheme was permitted as it was not one of the adjustments contemplated under Chapter 6 of the Access Code.

2254. In its final decision in relation to the second access arrangement period, the Authority accepted that a scheme such as the proposed D-factor scheme may have efficiency benefits in the provision of network services. The Authority considered the potential efficiency benefits of the proposed D-factor scheme arose due to the limited incentive that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. A saving in capital expenditure during an access arrangement period relative to the forecast for that period will give rise to a "reward" to the service provider of an amount equal to the rate of return and depreciation allowance on the amount of the saved investment. However, under a conventional scheme of regulation, any (above-forecast) non-capital costs that would be incurred by the service provider in achieving the efficiency gain in capital costs are not recoverable. Potentially a service provider may be worse off by delaying the capital project even though the substitution of non-capital costs for capital costs would have been efficient.

2255. Many non-network alternatives (including demand management programs) involve substituting non-capital costs for capital investment in a network to resolve network constraints. In circumstances where opportunities for non-network alternatives are not identified and addressed in cost forecasts for an access arrangement period, the potentially limited incentive to substitute non-capital costs for capital costs may create a disincentive for developing and implementing efficient non-network alternatives. This disincentive is increased by efficiency incentive schemes, as any additional non-capital costs incurred by the service provider may not only be unrecoverable, but may also reduce incentive payments that may otherwise accrue to the service provider from other, unrelated, efficiency gains.

2256. The D-factor scheme included in the current access arrangement seeks to address the disincentive to implement non-network alternatives to capital projects in resolving network constraints. In the final decision for the current access arrangement, the Authority took the view that section 6.2 of the Access Code is not exclusive as to the specific methods of price control (including adjustment mechanisms) and sections 6.1, 6.2 and 6.4 provide discretion as to the form of price control provided it meets the objectives in section 6.4 and complies with Chapter 6. The Authority considered it was appropriate to allow such adjustments under the access arrangement where there is a clear consistency with the objectives for a price control and the Code objective. On that basis, the Authority accepted that the proposed D-factor scheme was consistent with the requirements of the Access Code.

2257. On the particular provisions of the D-factor scheme, the Authority considered that the scheme as set out in Western Power's proposals for the second access arrangement period did not adequately constrain the operation of the scheme to circumstances where the deferral of capital expenditure or the implementation of demand management schemes is economically efficient. The original proposal required that there be an "approved" business case for the D-factor scheme to apply to an amount of expenditure; there was no explicit requirement for the business case to demonstrate efficiency in the relevant costs.

2258. The Authority determined that the operation of the D-factor scheme should be subject to any amount of operating expenditure or capital expenditure satisfying requirements of the Access Code that normally apply in determining amounts of costs that may be recovered through network tariffs. The Authority required the scheme to provide for the operation of the D-factor scheme to be subject to demonstration, to the Authority's satisfaction, that:

- any amount of operating expenditure satisfying the requirements of sections 6.40 and 6.41 of the Access Code, as relevant; and
- any amount of capital expenditure satisfying the requirements of section 6.51A of the Access Code.

2259. In the proposed revisions to the access arrangement, Western Power proposed that claims for deferred expenditure could only be made in relation to projects included in the D-factor Project List (provided to the Authority as confidential material) or the Transmission Network Development Plan. The D-factor Project List includes capital projects that are not certain enough to have been included in the expenditure forecasts for the third access arrangement period.

2260. In the Draft Decision, the Authority took the view that the D-factor Project List facilitates operation of the D-factor scheme as it assists assessment of whether a capital project has actually been deferred. However, the Authority also considered that it would be inconsistent with the objectives of section 6.4 of the Access Code and the Code objective for this list to include any projects that are not included in the current forecast of capital expenditure and that have been assessed under section 6.51A as meeting the tests under the Access Code for inclusion in the "forward-looking and efficient costs of providing covered services".

2261. The Authority therefore considered this proposed amendment moves the D-factor scheme away from its original purpose, which was to address the limited incentives that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. The current scheme applies only to deferrals of capital expenditure that have been included in the forecast of costs taken into account in determination of target revenue for the access arrangement period.

2262. In the Draft Decision, the Authority noted that Western Power has not claimed any expenditure in relation to the D-factor scheme. The Authority also gave further consideration to Synergy's submission that D-factor projects and any associated funding should be treated no differently to any other new facility to enable Western Power to provide covered services.

2263. The D-factor scheme was approved for the second access arrangement period to remove an apparent disincentive for the service provider to seek efficiency in capital costs where an increase in non-capital costs was necessary to achieve the efficiency on the basis that, otherwise, such non-capital costs could not be recovered. In the Draft Decision the Authority noted that, under the Access Code there is provision for the service provider to apply at any time under 6.76 and 6.41 to have these costs recovered, and took the view that the existing provisions of the Access Code in relation to the approval of non-capital costs, as set out in sections 6.40, 6.41 and 6.76, provide sufficient mechanisms to enable Western Power to claim any such costs as are contemplated by the proposed D-factor scheme.

2264. On this basis, the Authority did not consider that an additional mechanism such as the proposed D-factor scheme was necessary. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 61

The D-factor scheme must be removed from the proposed revised access arrangement.

2265. In response to the Draft Decision, Western Power has not accepted this amendment. Western Power notes that, while section 6.76 provides a mechanism for recovering operating costs during future access arrangement periods, the effect of subsequent sections of the Access Code, specifically section 6.79, is that operating costs incurred during the current access arrangement period cannot be recovered.

2266. As outlined above, if an application made for non-capital costs is approved by the Authority, then the Authority is bound by that determination when it next approves proposed revisions to the access arrangement. These clauses are virtually identical to those for pre approval of new facilities investment (i.e. sections 6.71, 6.72 and 6.74 of the Access Code). The only difference is that, in the case of new facilities investment, the Access Code only contains very general provisions regarding how the opening capital base for each access arrangement period should be established. However, in the case of non capital costs, section 6.4 only includes provision for forward looking costs.

2267. Consequently, as Western Power has adopted a roll forward method for establishing the opening capital base (which is one of the methods permitted by the Access Code), variations in capital expenditure during an access arrangement period compared with the amount forecast are included in the capital base providing the capital expenditure meets the new facilities investment test. This enables Western Power's return on and return of such investment to be included in target revenue at the next access arrangement review.

2268. However, in the case of non capital costs, there is no similar mechanism. As noted above, section 6.4 only refers to "forward looking costs". Section 6.4 also includes a number of specific items which must be included in target revenue. However, none of these relate to variations in non capital costs during an access arrangement period. The Authority therefore recognises there is currently no mechanism to allow retrospective recovery of non capital costs.

2269. As discussed in paragraphs 2259 to 2261, Western Power has proposed a change from the current D-factor scheme by including capital projects that are not certain enough to have been included in the expenditure forecasts for the third access arrangement period. The Authority considers this proposed amendment moves the D-factor scheme away from its original purpose, which was to address the limited incentives that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. The Authority requires Western Power to retain the existing provisions of the D-factor scheme, which applies only to deferrals of capital expenditure that have been included in the forecast of costs taken into account in determination of target revenue for the access arrangement period.

2270. Taking account of the concerns raised in Synergy's submission that D-factor projects and any associated funding should be treated no differently to any other new facility to enable Western Power to provide covered services, the Authority agrees that there is no need for the D-factor scheme to include capital expenditure as such expenditure can be rolled into the capital base, providing it meets the new facilities investment test. The Authority therefore requires the D-factor scheme to be amended to exclude expenditure in relation to new facilities investment.

2271. In relation to operating costs, as discussed above, the Authority recognises there is currently no mechanism to allow retrospective recovery of non capital costs and, therefore, accepts the need for the D-factor scheme in relation to operating expenditure. The current D-factor scheme only allows an amount in relation to operating expenditure to be added to target revenue at the next access arrangement period if there is an approved business case for the relevant expenditure that demonstrates to the Authority's satisfaction that the costs satisfy the requirements of sections 6.40 and 6.41 of the Access Code. The Authority considers this provision ensures that any operating expenditure approved under the D-factor scheme is required to meet the same efficiency test as any other operating expenditure.

2272. Clause 7.6.2 of the D-factor scheme states that an amount will be added to target revenue so that Western Power is financially neutral as a result of any additional non capital costs incurred as a result of deferring new facilities investment. The Authority considers that, for the avoidance of doubt, the clause needs to make clear that only costs in excess of any amounts already included in target revenue in relation to the deferred new facilities investment will be allowed.

2273. As discussed in paragraphs 388 to 389 above, the Authority has determined that the D-factor scheme should be extended to include network control services. Taking account of this and the matters discussed above, the following amendments are required to the D-factor scheme:

> 7.6.2 In the next access arrangement period, the Authority will add to Western Power's target revenue an amount so that Western Power is financially neutral as a result of:
>
> a) any additional non-capital costs incurred by Western Power as a result of deferring a new facilities investment project during this access arrangement period, <u>net of any amounts previously included in target revenue in relation to the deferred new facilities investment</u>; and

b) any additional non-capital costs ~~or new facilities investment~~ incurred by Western Power in relation to demand management initiatives <u>or network control services</u>.

7.6.3 In relation to 7.6.2a), the new facilities investment project that has been deferred must have been included in ~~either the D-factor Project List (provided to the Authority as confidential material) or the Transmission Network Development Plan.~~ <u>Western Power's forecast new facilities investment in its revised access arrangement information or supporting documentation, and in the Authority's allowed new facilities investment for this access arrangement period.</u>

7.6.4 In relation to 7.6.2a) and 7.6.2b), an amount will only be added to target revenue for the next access arrangement period if there is an approved business case for the relevant expenditure, and this business case is made available to the Authority. The business case must demonstrate to the Authority's satisfaction that:

a) the proposed non-capital costs satisfy the requirements of sections 6.40 and 6.41 of the Code, as relevant. ~~; and~~

~~b) the proposed new facilities investment satisfies the requirements of section 6.51A of the Code.~~

Required Amendment 42

The D-factor scheme must be amended as set out in paragraph 2273 above.

Deferral of Revenue

2274. As discussed above, in the Draft Decision the Authority determined that only part of the deferred revenue should be recovered during the third access arrangement period. Consequently the current adjustment mechanism in relation to the recovery of deferred revenue needs to be retained in the proposed revised access arrangement. Accordingly, the Draft Decision included the following required amendment.

Draft Decision Amendment 62

The current adjustment mechanism in relation to the recovery of deferred revenue must be retained in the proposed revised access arrangement with the deferred amounts of revenue to be updated to:

$48.6 million ($ as at 30 June 2012) for transmission services; and

$365.2 million ($ as at 30 June 2012) for distribution services.

2275. In response to the Draft Decision, Western Power has accepted the amendment in principle but has not accepted the Authority's values for deferred revenue. Instead, Western Power has used its proposed WACC to arrive at different figures. In the Final Decision, the Authority has determined the WACC to be 3.6 per cent which results in the value of deferred revenue at the beginning of AA4 to be $47.7 million ($ as at 30 June 2012) for the transmission service and $358.3 million ($ as at 30

June 2012) for the distribution service. Section 7.7 of the revised proposed revisions to the access arrangement must be amended to reflect this.

Required Amendment 43

The values in relation to the recovery of deferred revenue stated in section 7.7 of the revised proposed revisions to the access arrangement must be amended to:

$47.7 million ($ as at 30 June 2012) for transmission services; and

$358.3 million ($ as at 30 June 2012) for distribution services.

Treatment of Depreciation in Establishing the Opening Capital Base for the fourth access arrangement

2276. When establishing the opening capital base for the second and third access arrangement period, depreciation was based on the values forecast for the first and second access arrangement periods respectively. Forecast depreciation for the second and third access arrangement periods therefore took account of any differences between actual and forecast depreciation in the preceding period.

2277. In the proposed revisions to the access arrangement, Western Power proposed to continue this methodology in relation to investment categories subject to the investment adjustment mechanism. However, for investment categories not subject to the investment adjustment mechanism, Western Power proposed to use actual depreciation to establish the capital base at the commencement of the fourth access arrangement. The impact of this is that any difference between actual and forecast depreciation during the third access arrangement period will not be adjusted for in forecast depreciation for the fourth access arrangement period.

2278. Western Power claimed that “using actual depreciation provides the business an incentive to spend capital expenditure efficiently where service is not affected” and that “using actual depreciation to establish the AA4 capital base meets the Access Code objective as it promotes economically efficient investment in the network by providing an incentive to reduce capital expenditure”.

2279. In the Draft Decision the Authority did not agree that such an amendment is required and was concerned it would increase the incentive to over forecast capital expenditure. The current methodology ensures the service provider target revenue over time recovers all depreciation relating to actual expenditure. The proposed change could potentially result in Western Power recovering a higher level of depreciation through target revenue than is actually incurred.

2280. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 63

The proposed revised access arrangement must be amended to remove the proposed change to the treatment of depreciation in establishing the opening capital base for the fourth access arrangement.

2281. In response to the Draft Decision, Western Power has accepted this amendment and modified section 5.3.5 of the revised proposed revisions to the access arrangement accordingly. The Authority is satisfied that Western Power has complied with Draft Decision Amendment 63.

TRIGGER EVENTS

Access Code Requirements

2282. Under section 5.34 of the Access Code, an access arrangement may specify one or more trigger events. A trigger event is defined in the Access Code as a set of one or more circumstances specified in the access arrangement, the occurrence of which requires a service provider to submit proposed revisions to the Authority under section 4.37 of the Access Code.

2283. Under section 5.35 of the Access Code, trigger events may be either proposed by the service provider or included in an access arrangement by the Authority.

2284. Under section 5.36 of the Access Code, before determining whether a trigger event is consistent with the Code objective, the Authority must consider:

- whether the advantages of including the trigger event outweigh the disadvantages of doing so, in particular the disadvantages associated with decreased regulatory certainty; and
- whether the trigger event should be balanced by one or more other trigger events.

Current Access Arrangement

2285. The current access arrangement includes a broad specification of trigger events under clause 8.1:

> 8.1 Any significant unforeseen development which has a materially adverse impact on the service provider and which is:
>
> (i) outside the control of the service provider; and
>
> (ii) not something that the service provider, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and
>
> (iii) an event the impact of which is so substantial that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

2286. Clause 8.2 of the current access arrangement requires that Western Power must submit proposed revisions to the Authority within 30 business days after a trigger event has occurred.

Proposed Revisions

2287. Western Power proposed increasing the number of days by which it must submit proposed revisions to the Authority after a trigger event has occurred from 30 business days to 90 business days.

Considerations of the Authority

2288. In the Draft Decision the Authority accepted that the proposed increase in time for Western Power to submit proposed revisions to the Authority following a trigger event appeared reasonable. The Authority has received no further submissions in relation to this issue and, accordingly, accepts Western Power's proposed amendment.

STANDARD ACCESS CONTRACT

Access Code Requirements

2289. A standard access contract sets out the terms and conditions under which a user may obtain access to a reference service at the reference tariff. Section 5.1(b) of the Access Code requires that an access arrangement include a standard access contract for each reference service. An access arrangement may contain a single standard access contract in which the majority of terms and conditions apply to all reference services and the other terms and conditions apply only to specified reference services.

2290. The requirements for standard access contracts are set out in sections 5.3 to 5.5 of the Access Code:

5.3 A *standard access contract* must be:

(a) reasonable; and

(b) sufficiently detailed and complete to:

(i) form the basis of a commercially workable *access contract*; and

(ii) enable a *user* or *applicant* to determine the value represented by the *reference service* at the *reference tariff*.

5.4 A *standard access contract* may:

(a) be based in whole or in part upon the *model standard access contract*, in which case, to the extent that it is based on the *model standard access contract*, any matter which in the *model standard access contract* is left to be completed in the *access arrangement*, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the *model standard access contract*; and

(ii) section 5.3;

(iii) the *Code objective*;

and

(b) be formulated without any reference to the *model standard access contract* and is not required to reproduce, in whole or in part, the *model standard access contract*.

{Note: The intention of this section 5.4(b) is to ensure that the *service provider* is free to formulate its own *standard access contract* which complies with section 5.3 but is not based on the *model standard access contract*.}

5.5 The *Authority*:

(a) must determine that a *standard access contract* is consistent with section 5.3 and the *Code objective* to the extent that it reproduces without material omission or variation the *model standard access contract*; and

(b) otherwise must have regard to the *model standard access contract* in determining whether the *standard access contract* is consistent with section 5.3 and the *Code objective*.

Current Access Arrangement

2291. The current access arrangement includes a standard access contract (the electricity transfer access contract or **ETAC**) that applies to all of the reference services offered under the access arrangement.

Proposed Revisions

2292. In the proposed revisions to the access arrangement, Western Power has maintained the single electricity transfer access contract for all reference services (**proposed ETAC**). The proposed ETAC includes revisions made for the purposes of clarifying existing provisions, as well as substantive changes, or additions, to the contract.

2293. The principal revisions proposed for the ETAC include:[635]

- removal of clause 3.1(d), which permitted Western Power to provide a User with a modified service within the ETAC. Western Power has proposed that this service be provided as a non-reference service to ensure that the ETAC is only used for access to reference services;
- removal of the reference to ‘de-energisation’ in clause 3.6(c) to ensure that a connection point is not unintentionally deleted from an ETAC when the intention was to simply de-energise the connection point (e.g. where a user seeks a temporary interruption of service to be followed by a subsequent re-energisation, which may include situations where the user no longer has a contract with the customer at the connection point);
- amendment of the definition of ‘payment error’ in Schedule 1 to address all the situations covered by clause 8.6, and the insertion of new clauses 8.6(f) and 8.6(g) to clarify the timing of the operation of clause 8.6; and
- amendments to clause 9, including insertion of a new clause 9(c) which will require users, on receipt of a written request from Western Power, to increase the level of monetary security where the existing security no longer equals the charges for two months services, and insertion of a new clause 9(e) to manage security in situations where a parent company’s circumstances change.

Considerations of the Authority

2294. In considering the proposed revisions to the access arrangement, the Authority has considered whether the terms and conditions of the ETAC that are proposed to continue, are consistent with the requirements of the Access Code. In making this assessment, the Authority has taken into account evidence of practical experience from Western Power and Users with respect to the operation of the existing ETAC.

635 Proposed revised access arrangement, Appendix A.

Basis of Proposed Standard Access Contract

2295. In its submission to the first round of public consultation on the proposed revisions to the access arrangement, Synergy stated that "It is important to recognise the Standard Access Contract represents the minimum standards and terms for an access contract". In the Draft Decision, the Authority noted that this statement is not correct as a service provider and a potential user are free to negotiate any terms of access to a service (including terms which differ from a standard access contract). However, in the event of a dispute over the terms of an access contract for a reference service, the arbitrator must not make an award specifying terms of an access contract that are inconsistent with the standard access contract for the reference service in the access arrangement (section 10.21 of the Access Code).

2296. In its submission in response to the draft decision, Synergy submits that the Authority's view, as expressed in the Draft Decision, is contrary to section 104(2)(c)(ii) of the *Electricity Industry Act 2004* (**EI Act**) which states:

> "Provision is to be made in the Code-
>
> …
>
> (c) as to the lodgement by the network service provider of an arrangement for network infrastructure facilities covered by the Code setting out –
>
> …
>
> (ii) the basic terms and conditions that will apply to access to service unless an access agreement contains different terms and conditions; and"

2297. The Authority does not agree that the reference to *basic* terms and conditions in section 104(2)(c)(ii) is equivalent to a requirement that the standard access contract contain *minimum* terms and conditions, although it accepts that this may be the way the service provider treats the contract in negotiations with users or applicants. The test in the Access Code is whether the standard access contract is reasonable and sufficiently detailed and complete to:

(a) form the basis of a workable access contract; and

(b) to enable the user or applicant to determine what value it will receive for the reference service at the reference tariff.

2298. In making its assessment under section 5.3, the Authority is mindful of observations made by the Full Federal Court on the risks of an overly prescriptive regulatory approach to model contracts in *ACCC v Telstra* (2009)[636]. In that case, the Court considered whether a requirement that the ACCC determine model terms and conditions for access to core services under the then *Trade Practices Act 1974* (Cth) required the ACCC to make an exhaustive determination of all the terms and conditions that could reasonably be made in relation to access to a service.

2299. The Court held that the ACCC was required to make a written determination setting out at least some model terms and conditions relating to access to each core

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636 ACCC v Telstra (2009) 176 FCR 203 at [58].

service, but was not required to provide an all-encompassing set of model terms and conditions for each core service. In this regard, the court agreed with the ACCC's submission that:

> "…terms and conditions that are more prescriptive and comprehensive may facilitate quicker access. However, against that consideration, …[must be]… balanced[d] the often competing interests of the parties involved and the need not to harm competition or efficient investment by promulgating terms and conditions which can have unforeseen effects. The risk of such effects is heightened by …[the regulator's]… comparative lack of information, knowledge and experience when measured against the expertise of the actual participants in the …industry."

2300. The Authority considers that the requirement in section 104(2)(c)(ii) of the EI Act, that the Code provide for the basic terms and conditions applying to access to services, is reflected in the requirement in section 5.3(b)(i) of the Access Code that a standard access contract must be "sufficiently detailed and complete" to form the basis of a "commercially workable access contract".

2301. On this basis, the Authority agrees with Synergy's submission that the ETAC is intended to have practical effect and to set out basic terms and conditions capable of forming a contract applying to access to Western Power's services. However, the Authority does not consider that it follows from this that the terms and conditions must be exhaustive or that they must reflect "minimum" standards.

2302. The Authority also does not consider it is necessary for it to insert provisions into the ETAC that mirror the regulatory obligations imposed on the network operator. The Authority disagrees with Synergy's submission that not doing so is in breach of the Authority's obligation under section 4.30(d) of the Access Code to have regard to written laws and statutory instruments. If an obligation is already imposed on Western Power by statute, there is no reason for the Authority to replicate the obligation in the ETAC unless the Authority is of the view that, absent an equivalent contractual provision, the ETAC will not constitute a "commercially workable" access contract or otherwise not comply with section 5.3 of the Access Code.

2303. Synergy's submission in response to the Draft Decision also submits that it is contrary to the public interest for the Authority not to ensure that Western Power's non-compliance with a statutory obligation has an adverse financial impact on Western Power:

> "The Authority must assist in driving regulatory outcomes reflected in law by creating real financial consequences from a failure to comply. In turn it is not reasonable for the Authority (and therefore in contravention of section 5.3 of the Code) to have the *standard access contract* reflect or incentivise different commercial outcomes than the outcome stipulated and contemplated by laws and regulations."

2304. The Authority considers Synergy's submission misunderstands the role of the Authority in approving a proposed access arrangement and a standard access contract. The Authority's role is not to use the access arrangement and access contract to enforce Western Power's compliance with its existing statutory obligations. It was open to the drafters of existing legislation applicable to Western Power to specify financial or other adverse consequences to apply in the event of non-compliance with these obligations. It is not the Authority's role under the Access Code to second-guess or supplement these consequences through the access arrangement or terms and conditions of the ETAC.

2305. However, the Authority agrees with Synergy that it is clear from section 5.3 of the Access Code that the Authority must ensure that key issues or material terms are addressed in the ETAC in order to form a commercially workable agreement.

2306. A commercially workable contract is one which is based on “business common-sense and commercial reality”[637] and one which “avoid[s] absurdity or inconsistency” or, consequences which appear to be “capricious, unreasonable, inconvenient or unjust”.[638]

2307. Accordingly, the Authority may decide to insert, amend or delete a term in the ETAC if it considers that to do so will make the contract consistent with business common-sense and commercial reality or avoid an unreasonable or unjust outcome. In deciding whether the ETAC complies with section 5.3 and the Access Code objective, the Authority must also have regard to the model standard access contract pursuant to section 5.5 of the Access Code.

2308. In its submission to the first round of public consultation, Synergy also questions whether the standard access contract proposed is based on section 5.4(a) or (b) of the Access Code, but notes it appears to have been developed under section 5.4(b) of the Access Code i.e. formulated without any reference to the model standard access contract and therefore not required to reproduce, in whole or in part, the model standard access contract. Synergy notes that, if this is the case, then section 5.5(b) of the Access Code applies when making a determination on the proposed standard access contract and requests Western Power to make this clear in its proposed revised access arrangement.

2309. As noted in the Draft Decision, the Authority confirms that it does have regard to the model standard access contract in determining whether the standard access contract is consistent with section 5.3 and the Code objective as required under section 5.5 of the Access Code. However, this is a requirement placed on the Authority and is not something which needs to be referred to by Western Power in its proposed revised access arrangement.

2310. In its submission to the first round of public consultation, Landfill Gas and Power submitted that the terms of the contract should have regard to fitness for purpose. Using itself as an example, Landfill Gas and Power notes that it is a small generator-retailer operating four small power stations supplying fewer than 100 customers and submits that the insurance obligations should be commensurate with this, rather than the same as apply to much larger entities. Landfill Gas and Power submits that, as electricity retailers are arms-length users with no practical functionality to affect the network, the network contract should reflect this through less onerous conditions.

2311. As set out in the Draft Decision, the Authority notes that section 5.1(b) of the Code requires an access arrangement to include a standard access contract for each reference service. The note to section 5.1(b) suggests an access arrangement may contain a single standard access contract in which the majority of terms and conditions apply to all reference services. The requirement of the Access Code is that the standard access contract is reasonable and sufficiently detailed and complete to form the basis of a commercially workable access contract. There is no requirement to provide different levels of standard access contracts for the same

[637] BB Australia Pty Ltd v Karioi [2010] NSWCA 347 at [37].

[638] City of Sydney v Streetscape Projects (2011) 94 IPR 35 at [312] and [313]].

reference service. However, under section 2.4A of the Access Code, parties may negotiate and agree an access contract on any terms, including terms which differ from a standard access contract.

Removal of Modified Service (clause 3.1(d))

2312. Western Power has proposed removal of clause 3.1(d), which had permitted the provision of a modified service to a user within the ETAC. For the third access arrangement period Western Power has proposed that such services will be provided as non-reference services to ensure that the ETAC is only used for access to reference services.

> 3.1(d) Notwithstanding clause 3.1(a)(i), Western Power* may provide the User* with a Modified Service* for a Connection Point* stipulated in Part 4 of Schedule 3 (if any) until:
>
> (i) the date set out in Part 4 of Schedule 3 for the Connection Point*; or
>
> (ii) until the events or works (as applicable) set out in Part 4 of Schedule 3 for that Connection Point* are completed to Western Power*'s satisfaction (acting as a Reasonable and Prudent Person*)
>
> as applicable.

2313. The inclusion of this clause in the ETAC was approved by the Authority in the current access arrangement. At the time, the Authority observed that there was nothing in clause 3.1(d) that altered any obligation arising under either the Access Code or the access arrangement for Western Power to undertake necessary works or meet conditions for the provision of a contracted service. Further, the provision for a modified service implies that, in practice, a user and Western Power will need to agree on provision of a service other than a reference service, or agree on provision of a service on terms and conditions other than those contained in a standard access contract. On that basis, the Authority considered that clause 3.1(d) was consistent with section 5.3 of the Access Code.

2314. Conversely, deleting clause 3.1(d) does not alter any obligation arising under either the Access Code or the access arrangement for Western Power to undertake necessary works or meet conditions for the provision of a contracted service. On this basis, the Authority accepts the deletion of the clause.

Deletion of a Connection Point (clause 3.6)

2315. Clause 3.6 of the proposed ETAC provides for the user to request deletion of a connection point from the contract. Clause 3.6 also sets out the circumstances in which Western Power is obliged to comply with the request. Western Power's proposed revisions to clause 3.6 (as submitted in May 2012) are set out below with the proposed new text underlined.

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* <u>where:</u>

<u>(i) a transfer request under the Customer Transfer Code*; or</u>

<u>(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i); or</u>

<u>(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.</u>

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant*, excluding Generating Plant* up to and including 30kVA which is being used to offset load, at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant and Generating Plant* up to and including 30kVA which is being used to offset load, at a Connection Point*, at least one month before the planned Disconnection*.

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must notify the User* that it accepts the deletion, and the date that the deletion takes effect, if:-

(i) Western Power* has successfully processed a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* has been added to another Access Contract* by some other means; or

~~(iii) Western Power* has De-energised* the Connection Point* under this Contract* or a law*; or~~

(~~iv)~~<u>(iii)</u> the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*,

as soon as reasonably practicable, otherwise Western Power* may notify the User* as soon as reasonably practicable that it rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

Western Power's proposed amendments to Clause 3.6(a)

2316. Western Power expanded clause 3.6(a) to clarify the grounds upon which deletion of a connection point may be requested. In effect, the amendments to clause 3.6(a) make the clause consistent with clause 3.6(c) which sets out the circumstances in which Western Power must accept a deletion request.

2317. In its submission to the first round of public consultation, Synergy included a revised clause 3.6 which deleted Western Power's proposed new clauses 3.6(a)(i), (ii) and (iii). Synergy did not provide any specific reasoning for doing this. In the Draft Decision the Authority took the view that Western Power's proposed amendment clarifies the circumstances in which a user can request deletion of a connection point and accepted the proposed amendment by Western Power.

2318. Synergy's submission also noted that the Customer Transfer Code only permits a retailer to make a customer transfer request. To reflect this, Western Power proposed that clause 3.6(a)(i) should be amended to read as follows:

> "a transfer request has been made in relation to the Customer* for that Connection Point* under the Customer Transfer Code*; or"

2319. In the Draft Decision, the Authority considered Western Power's proposed amendment to clause 3.6(a)(i) adequately dealt with the point raised by Synergy that the Customer Transfer Code only permits a retailer to make a customer transfer request. Consequently, Draft Decision Amendment 64 incorporated the amendment to clause 3.6(a)(i) as set out in paragraph 2318. In response to the Draft Decision, Western Power has accepted Draft Decision Amendment 64.

Western Power's proposed amendments to Clause 3.6(c)(iii)

2320. Western Power proposed the removal of the reference to 'de-energisation' in clause 3.6(c) to ensure that a connection point is not unintentionally deleted from an ETAC when the intention was to simply de-energise the connection point (e.g. where a user seeks a temporary interruption of service to be followed by a subsequent re-energisation).

2321. Western Power noted in its access arrangement information that deletion and de-energisation are separate concepts. Western Power describes de-energisation as a temporary interruption or cessation of electricity supply, whereas deletion is a permanent cessation. Western Power considers there should only be a permanent removal of a connection point from a user where the connection point has been transferred to another user, or where the equipment at the connection point has been permanently disconnected. Western Power considers that, as long as a connection point still exists (i.e. it has only been de-energised rather than the equipment at that point removed), then the costs that are still incurred in maintaining the equipment should continue to be allocated to the User. Western Power considers that if a user wishes to cease paying charges in respect of a connection point because it no longer has a contract with the customer or generator at that connection point, then it must either have that connection point transferred to another user or have it deleted (not simply de-energised).

2322. In its submission to the first round of public consultation, Synergy did not directly respond to this point but proposed (as set out at paragraph 2328 below) the inclusion of a requirement that, where the user has requested the deletion of the connection point because the user no longer has a contract with a customer or a generator at the connection point, then Western Power should be required to effect the deletion within the timeframe required under the ETAC, or any other contract or law.

2323. In the Draft Decision, the Authority noted that, under the proposed access contract terms and conditions, even if a contract between a retailer and a customer ceases for some reason, the connection point will remain subject to the access contract of the retailer until it is transferred, added to another access contract or is disconnected. The Authority considered this to be reasonable and that connection to the network should attract some charging for network services. The retailer can either apply for permanent disconnection or transfer to another retailer.

2324. In the Draft Decision, the Authority observed that, in the normal course of events, there would never be a connection point that is not subject to the access contract for a retailer or other network user. However, if for some reason a connection point exists where there is no contract with a retailer, then that connection point would revert to the "default supplier" retailer under section 59 of the Act.

2325. Synergy's submission in response to the Draft Decision raised concerns about its ability to recover the network and energy costs of electricity taken by a customer in the period between the deemed allocation of the customer and Western Power's notification to Synergy of the existence of the default contract in respect of the connection point.

2326. The Authority notes Synergy's concerns and considers that the ETAC should be amended to require Western Power to act "as soon as reasonably practicable" to advise Synergy of any connection points which have reverted to the "default supplier" retailer. The Authority requires that this amendment be included in clause 3.7 as it relates to an amendment to connection point data, rather than deletion of a connection point. This required amendment is addressed at paragraph 2364 below.

Synergy's proposed amendments to clause 3.6

2327. In its submission to the first round of public consultation, Synergy raised other concerns with clause 3.6. Synergy submitted that, in its practical experience, the terms of the proposed standard access contract dealing with deletion of a connection point do not place a positive obligation on Western Power to effect such a deletion in accordance with the legal framework or the knowledge of, or a request by, the retailer. Synergy noted that it has suffered and continues to suffer financial loss and damages when Western Power permits a person to use a connection point subject to Synergy's access contract and does not act on a notification from Synergy to delete an entry or exit connection point from Synergy's access contract. Synergy states it has also suffered the converse of this scenario where a connection point has been deleted from its access contract without Synergy issuing any notification or instructions to do so under its access contract, thus creating issues between Synergy under its supply contract with the customer. Synergy does not consider these incidents have promoted the economically efficient operation and use of the network and network services. If the situation is not satisfactorily addressed, the additional costs and liabilities that Synergy incurs due to the acts or omissions of the network operator will need to be passed on to all consumers.

2328. Synergy considers it is not reasonable for a retailer to be liable for an act or omission of the network operator, including inefficiencies in the network operator's internal processes, to effect the removal of a connection point from the retailer's access contract. In addition, Synergy considers that existing clause 3.6 of the standard access contract is not sufficiently detailed and complete to form the basis of a commercially workable access contract. Synergy considers this lack of clarity exposes retailers to loss or damage resulting from the acts or omissions of the network operator and, to prevent this, considers the standard access contract should place a positive obligation on the network operator to effect a deletion only in accordance with the Customer Transfer Code or the retailer's instructions.

2329. Synergy proposed the following changes to clause 3.6, which it considers address the issues it has raised and recognises the operation of photovoltaic systems connected to the network:

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* ~~where~~:

~~(i) the Customer* in relation to the Connection Point* has made a transfer request under the Customer Transfer Code*; or~~

~~(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i);~~

~~or~~

~~(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.~~

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant* with a capacity greater than 30 kVA at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant) (and Generating Plant* up to and including 30kVA) at a Connection Point*, in accordance with the applicable "model service level agreement" or "service level agreement" under the Metering Code* (as amended or substituted from time to time) ~~at least one month before the planned Disconnection*.~~

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must ~~notify the User* that it accepts the deletion, and the date that the deletion takes effect, if~~;

(i) where Western Power* is required to effect ~~has successfully processed~~ a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code* - delete the Connection Point* by the time the transfer is to take place under the Customer Transfer Code*; or

(ii) where the Connection Point* is required to be ~~has been~~ added to another Access Contract* by some other means – delete the Connection Point* as contemplated by that means; or

(iii) where the User* has requested the deletion of the Connection Point* because the User* no longer has a contract with a Customer* or a Generator* at the Connection Point* - delete the Connection Point* by the time within which Western Power* is required to De-energise* the Connection Point* under this Contract*, any other contract or a Law*; or ~~the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*,~~

~~otherwise Western Power* may notify the User* that it rejects the deletion~~.

(iv) where the User* has given Western Power* a notice under clause 3.6(a) that complies with clause 3.6(b)(i) – by the time of the planned Disconnection*; or

(v) where the User* has given Western Power* a notice under clause 3.6(a) that complies with clause 3.6(b)(ii) – by the time the Disconnection* is required to take place under the applicable "model service level agreement' or "service level agreement' under the Metering Code*

and as soon as practicable notify the User* that it accepts the deletion, and the date that the deletion takes effect, otherwise notify the User* as soon as practicable that Western Power* rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

(f) Notices under clause 3.6 may be issued and delivered in accordance with processes determined by mutual agreement of the Parties* (for example, without limitation, Build Pack* communications)."

2330. The Authority addresses each of Synergy's concerns and proposed amendments below.

Removal of Connection Points without consent of User

2331. The explicit protection of users against an unrequested deletion of a connection point was raised during the second access arrangement review. As set out in its further final decision, the Authority determined that clause 3.6 should be amended to include this protection and Western Power agreed to insert clause 3.6(d):

3.6(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

2332. The Authority considers clause 3.6(d) adequately protects users as Western Power is only able to delete a connection point where requested by a user, or if required by law (the Customer Transfer Code).

2333. If Synergy does not consider Western Power is complying with these provisions, then any such instances need to be resolved between Synergy and Western Power. As discussed in paragraph 2304 above, the Authority's role is not to use the access arrangement and access contract to enforce Western Power's compliance with its existing statutory obligations.

2334. The Authority also notes that under clause 3.6(e), if Western Power wilfully breaches clause 3.6(d) it is liable to the user for any damage suffered and the exclusion of liability for indirect damages does not apply. If Western Power breaches clause 3.6(d) in circumstances which are not a wilful default it will still be liable for the losses suffered by the user but subject to the limitation of liability provisions set out in the ETAC.

Failure to Delete Connection Points in response to User's request

2335. The Authority notes that clause 3.6(c) clearly provides that Western Power must accept a deletion of a connection point if:

- Western Power has successfully processed a Customer transfer request in relation to the Connection Point under the Customer Transfer Code; or
- the connection point has otherwise been added to another Access Contract; or
- the equipment at the connection point has been permanently disconnected.

2336. The Authority also notes that clause 4.10 of the Customer Transfer Code obliges Western Power to process transfer requests and sets out the timeframes within which this is to be done.

2337. In the Draft Decision the Authority determined that the existing provisions are adequate both in terms of setting out the circumstances in which Western Power is required to delete connection points and ensuring that Western Power complies with such requests.

2338. The Authority has not changed its view in the Final Decision and notes that clause 3.6(c) requires Western Power to notify the user as soon as reasonably practicable whether it accepts or rejects the deletion.

2339. As the Authority noted in paragraph 2331 above in relation to removal of connection points without the consent of the user, if Synergy considers Western Power has failed to delete a connection point in response to a request from Synergy, then any such instances need to be resolved between Synergy and Western Power. It is not a matter to be resolved through development of the ETAC.

Synergy's proposed clause 3.6(a)

2340. Synergy's proposal is considered at paragraph 2316 above.

Synergy's proposed clause 3.6(b)

2341. In its proposed amendment to clause 3.6(b), Synergy provided that generators with capacity up to and including 30 kVA should not be required to give six months notice for permanent disconnection of a connection point. Instead, it proposed that the notice period for generators up to and including 30 kVA and for all consuming plant should be linked to the applicable service level agreement.

2342. Western Power's proposed revisions to the access arrangement did not include any amendments to the current provisions of clause 3.6(b). In response to a query from the Authority, Western Power noted that not all users are required to adopt the model service level agreement (**MLSA**) and a different service level agreement under the Metering Code may be negotiated between the parties that may not necessarily set out timeframes for deletion of connection points. Western Power also noted that the MSLA includes a supply abolishment service, which is the requirement to remove metering installations completely but is not the same as deletion of a connection point, which requires removal of connection assets in addition to metering equipment. Further, Western Power says that the existing clause 3.6(b) is concerned with the timeframes for requesting deletion of a connection point, not the time for undertaking the deletion.

2343. In the Draft Decision, the Authority took the view that it is inappropriate to cross reference the timeframes in clause 3.6(b) to service level agreements and that it would provide greater clarity to include the timeframes in the ETAC as is currently the case.

2344. The Authority also determined that the current requirements in relation to generators where there is no offsetting load should not be changed. However, for generators up to and including 30 kVA that are being used to offset load (for example, domestic photovoltaic systems), the notice period should be the same as for consuming plant (i.e. one month).

2345. Synergy's submission in response to the Draft Decision submits that the Authority's required amendment to clause 3.6(b)(ii) is contrary to clauses 4.30(b) and (d) of the Access Code. Synergy also suggests that the amendment is contrary to the current practice for abolishing the supply for residential homes, the services under clause 5.2 of the Metering Code and the MLSA.

2346. One of the difficulties in assessing the submissions of the parties in relation to clause 3.6(b) is the lack of clarity and consistency in the meaning of terms such as "supply abolishment", "de-energise", "deletion" of a connection point, "Disconnection" and "permanent Disconnection". "Supply abolishment" is not a defined term in the MLSA. However, from the description of "supply abolishment" in item 3 of Schedule 2 to the MLSA, it is clear that it relates to removal of metering installations completely, with the effect that the NMI (national market identifier) applicable to the connection point becomes extinct.

2347. Deletion of a connection point is also not defined in the ETAC but, from the terms of clause 3.6(a), appears to include a permanent Disconnection, where Disconnect is defined in Schedule 1 to mean, in respect of a connection point, "physically detach Network Assets from assets owned by another person at the Connection Point". Network Assets is defined to mean the apparatus, equipment, plant and buildings used to provide or in connection with providing Covered Services on the Network, which assets are either Connection Assets or Shared Assets. It is likely that removal of metering equipment would fall within this broad definition.

2348. The Authority continues to hold the view that, given that service level agreement requirements are not uniform for all users, there are difficulties in linking the timeframes in clause 3.6(b) to service level agreements and that it provides greater clarity to include the timeframes in the ETAC as is currently the case. However, it appears from Synergy's submission that there is a degree of overlap between the obligations under the MSLA for the supply abolishment service (which relates to removal of metering equipment and does not require prior notice) and the notice provisions in clause 3.6(b) dealing with permanent disconnection of generators. In the circumstances, to make the ETAC commercially workable, the Authority considers that clause 3.6(c) should be amended to clarify that, to the extent that the MSLA applies, the user need not comply with the notice requirement in respect of removal of equipment pursuant to the supply abolishment service in the MLSA.

Synergy's proposed clause 3.6(c)

2349. Clause 3.6(c) sets out the requirements for Western Power to notify users when it accepts a request for deleting a connection and the date the deletion takes effect.

Synergy proposed additional wording, which it considers clarifies the requirements and included an obligation for Western Power to notify users "as soon as practicable".

2350. The Authority queried the implications of Synergy's proposed amendments with Western Power. Western Power stated it considered that the standard proposed by Synergy of "as soon as practicable" is too high. Western Power considers the current position (that is, notification is given within the time required by law or within a reasonable time[639]) is appropriate and that it would be wrong to elevate the obligations in relation to deletion of connection points above the various other obligations and activities that Western Power has in relation to its network.

2351. Western Power also made the following points:

- The transfer process is adequately accommodated by the ETAC's existing wording and Synergy's proposed changes to clause 3.6(c)(i) confuse issues and are not consistent with the Customer Transfer Code.
- Synergy's proposed amendment to clause 3.6(c)(ii) is incorrect as the test is not whether a connection point is required to be added to another access contract but whether it has in fact been added.
- It is not appropriate to cross-refer to service level agreements under the Metering Code as Synergy has done in its proposed clause 3.6(c)(v), because not all users have service level agreements with timeframes linked to clause 3.6(c)(v) and, where there are such agreements, clause 3.6(c)(v) deals with a wider range of issues than is required to be dealt with in service level agreements under the Metering Code.

2352. In the Draft Decision the Authority took the view that Western Power's proposed drafting of clause 3.6 adequately set out the circumstances in which users may give notice to Western Power to delete a Connection Point and the process Western Power must follow. However, the Authority considered that Synergy's request that Western Power be expressly required to notify users "as soon as practicable" was not unreasonable, and considered the addition of the word "reasonably" before practicable would take account of any reasonable processes Western Power is required to carry out before notifying users. Therefore, in the Draft Decision the Authority required that clause 3.6(c) should be amended to read as follows:

> " <u>as soon as reasonably practicable</u>, otherwise Western Power* may notify the User* that it rejects the deletion <u>as soon as reasonably practicable</u>."

2353. The Authority notes the matters raised in Synergy's submission in response to the Draft Decision in relation to the need for timeframes for disconnection processes to be in line with the MSLA as discussed in paragraphs 2345 to 2348 above are also relevant to clause 3.6(c). Consequently the Authority requires a similar amendment to that required for clause 3.6(b) (i.e. clause 3.6(c) should be amended to clarify that, to the extent that the MSLA applies, Western Power must comply with relevant

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639 Western Power considers that, as clause 3.6(c) is silent in respect of timeframes, notification must be given in accordance with requirements of law (as required by clause 37.1 of the electricity transfer access contract) or, where no timeframe is prescribed, then notification must be given within a reasonable time based on case law (eg N C Seddon and M P Ellinghaus, *Cheshire and Fifoot's Law of Contract*, Ninth Australian Edition, paragraph 21.19, p. 1027).

supply abolishment timeframes in the MSLA notwithstanding the terms of clause 3.6(c)).

Synergy's proposed clause 3.6(f)

2354. Synergy proposed adding an additional clause relating to processes for issuing and delivering notices under clause 3.6.

2355. In the Draft Decision the Authority took the view that the standard access contract already contains sufficient provisions in relation to notices and does not consider it necessary or desirable to include any further provisions. Clause 35 of the current ETAC deals with processes for issuing and delivering notices. The Authority has not altered its view on this and notes Synergy has not provided any further reasoning in its submission in response to the Draft Decision to support the introduction of its proposed clause 3.6(f).

Summary of required amendments for clause 3.6

2356. In the Draft Decision, the Authority required clause 3.6 to be amended as follows:

Draft Decision Amendment 64

The Authority requires that clause 3.6 be amended as set out below.

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* where:

(i) ~~the Customer* in relation to the Connection Point* has made~~ a transfer request has been made in relation to the Customer* for that Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i); or

(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant*, excluding generating plant up to and including 30 kVA which is being used to offset load, at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant and generating plant up to and including 30 kVA which is being used to offset load, at a Connection Point*, at least one month before the planned Disconnection*.

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must notify the User* that it accepts the deletion, and the date that the deletion takes effect, if;

(i) Western Power* has successfully processed a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* has been added to another Access Contract* by some other means; or

~~(iii) Western Power* has De-energised* the Connection Point* under this Contract* or a law*; or~~

(~~iv)~~(iii) the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*,

as soon as reasonably practicable, otherwise Western Power* may notify the User* as soon as reasonably practicable that it rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

2357. In response to the Draft Decision, Western Power has revised proposed revisions to the access arrangement to reflect Draft Decision Amendment 64 in its entirety.

2358. As discussed in paragraphs 2345 to 2346 and paragraph 2353 above, Synergy's submission in response to the Draft Decision has provided further reasoning to support its view that the timeframes for disconnection processes need to be in line with the MSLA. For the reasons outlined above, the Authority considers a further amendment is required to clause 3.6(b) and (c).

Required Amendment 44

Clause 3.6(b) and (c) of the ETAC must be amended to clarify that, to the extent the model service level agreement applies, Western Power must comply with any relevant disconnection timeframes in the model service level agreement.

Notification of permanent reconfigurations and "default supplier" reversions (clause 3.7)

2359. Clause 3.7 sets out requirements for amending connection point data. Western Power did not propose any amendments to this clause, however, the Authority notes the numbering of its sub-clauses contains errors that require amendment.

2360. In its submission to the first round of public consultation, Synergy raised a concern in relation to clause 3.7(g).[640] Synergy submitted that it was necessary to clarify and restrict the application of clause 3.7(g) in the proposed standard access

[640] Western Power's proposed revised electricity transfer access contract has incorrectly numbered this as clause 3.7(e) which is the reference Synergy has used in its submission. The correct clause number is 3.7(g).

contract to circumstances in which Western Power has implemented a permanent reconfiguration only where it is legally entitled to do so. Synergy considered the current drafting of the clause results in it being applicable to situations where Western Power has physically undertaken a permanent reconfiguration, irrespective of whether Western Power did so in accordance with the regulatory regime.

2361. Synergy considers that in these situations it is not reasonable or commercially workable for Synergy and other retailers to commercially suffer the consequences and liabilities of a permanent reconfiguration that has been implemented by Western Power contrary to law and the regulatory regime. Synergy notes that its practical experience has highlighted that an amendment is necessary and proposes that clause 3.7(e) be amended as follows:

> 3.7(e) Subject to clause 3.7(h), where Western Power*, <u>in accordance with its legal rights and obligations,</u> causes a Permanent Reconfiguration* of the Network* which results in the information contained in the Contract Database* having to be updated…"

2362. The Authority queried Western Power regarding the concerns raised by Synergy. Western Power considered that, as Synergy had not provided any specific examples to illustrate the concerns it was difficult for Western Power to respond. However, Western Power noted that clause 37.1 of the ETAC already requires Western Power to comply with applicable laws so, in its view, it is unnecessary to repeat such requirements elsewhere in the standard access contract.

2363. The Authority considers that clause 37.1 adequately ensures that Western Power must comply with applicable laws and that the amendment to clause 3.7(e) proposed by Synergy is unnecessary. As discussed in paragraph 2304, the Authority's role is not to use the access arrangement and access contract to enforce Western Power's compliance with its existing statutory obligations. If Synergy is aware of instances where Western Power has not complied with its obligations then such matters should be raised with Western Power.

2364. As discussed in paragraph 2352 above, the Authority considers that the ETAC should be amended to require Western Power to act "as soon as reasonably practicable" to advise a user of any connection points which have reverted to the "default supplier" retailer.

Required Amendment 45

Clause 3.7 of the ETAC must be amended to require Western Power to act "as soon as reasonably practicable" to advise a user of any connections points which have reverted to it as a "default supplier" retailer.

Limitation on Liability (clause 6.2(e), 19.2 and 19.5)

2365. Western Power did not propose any amendments in relation to liability but submissions from Synergy and the Office of Energy raised a number of issues.

2366. Synergy's submission to the first round of public consultation considered there is a lack of clarity and certainty in the standard access contract with respect to a retailer's liability for actions resulting in direct damages. Synergy submitted that the most efficient way to manage risk is to assign it to the party best placed to manage it. Therefore, Synergy submits that the specific liability provisions in the standard access contract, in particular clauses 6.2, 19.2 and 19.5, need to be reviewed in the context of assigning risk to the party best able to manage it. Synergy submits that, in this respect, the standard access contract does not represent the minimum conditions for users and, in fact, treats a retailer no differently to a generator.

2367. In the Draft Decision the Authority observed that, as set out at paragraph 2295 above, Synergy's view that the standard access contract should represent the minimum conditions for users is not correct. There is also no requirement under the Access Code to provide separate standard access contracts for retailers and generators.

2368. Synergy's submission to the first round of public consultation noted that clause 6.2(e) purports to give retailers some relief by allowing Western Power to establish a connection contract with the controller of the equipment which Western Power approves to connect to its network. However, Synergy states that Western Power has declined to establish these connection contracts, with the result that the retailer is liable for the actions of the controller, despite Western Power inspecting and approving the controller to connect equipment to the network. Synergy considers this practice by Western Power also requires retailers to police the activities of controllers of the network, including inspecting and making sure controllers connect to the network in accordance with the connection approval provided by Western Power.

2369. Synergy submitted it is not reasonable, and is contrary to section 5.3 of the Access Code, for Western Power to have no liability in circumstances where it inspects and approves the connection of equipment and facilities to the network.

2370. Consequently, Synergy requested the Authority to make the following amendments to clause 6.2(e) of the standard access contract:

> 6.2(e) For the avoidance of doubt, if the User* is in breach of clause 6.2(a), then the User* is liable for, and must indemnify Western Power* pursuant to clause 19.2 against any Direct Damage* caused by, consequent upon or arising out of the acts and omissions, negligent or otherwise, of the Controller* to the extent that the acts or omissions, negligent or otherwise, of the Controller* are attributable to that breach, unless the Controller* has entered into a Connection Contract* with Western Power* <u>or Western Power has refused to enter into a Connection Contract* with the Controller*.</u>

2371. In the Draft Decision, the Authority noted that Synergy had made similar submissions in respect of clause 6.2 at the time of the second access arrangement review. In response to these submissions the Authority required the inclusion of an indemnity from Western Power to Users (which is set out in clause 6.2(g) of the ETAC) against costs incurred by Users in taking action against Controllers to procure compliance with the ETAC.

2372. The Authority's reasons relating to the required amendment were:

- the Model Access Contract requires the User to ensure (and provides that the User is liable for) compliance by the Controller of Connection Points over a specified capacity - specifically those Connection Points referred to in clause A3.38 of the Model Access Contract, which corresponds to clause 6.1 of the current ETAC ;
- given the terms of the Model Access Contract, it is consistent with the Code objective for the User to take responsibility for those Connection Points; and

- for Connection Points not referred to in clause 6.1 the Authority determined that the User was only required to take action to enforce compliance of the Controller of those Connection Points if Western Power provided the indemnity in clause 6.2(g).

2373. In response to the concerns raised by Synergy in relation to connection contracts with controllers, Western Power submitted that Synergy's proposed amendment to clause 6.2(e) was unclear and unworkable, particularly because it was unclear how the test would be applied and at which point refusal would be deemed to have occurred. To illustrate, Western Power queried whether it would be treated as having refused to enter into a contract with a controller if, despite the User wanting Western Power to do so, the Controller refuses to enter into the relevant contract.

2374. In the Draft Decision the Authority took the view that Synergy's proposed amendments to clause 6.2(e) were unclear and unworkable, and would result in ambiguity.

2375. In its submission in response to the Draft Decision, Synergy submits that the Authority must clarify how the standard access contract is intended to operate in circumstances where:

- Western Power refuses to address or mitigate any connection and network risk with a Controller through a Connection Contract; and
- the nature of the operations is too technical and complex for a retailer to supply the Controller unless the Controller has a Connection Contract with Western Power.

2376. The matters raised by Synergy are expressly addressed by the Authority in the Draft Decision. That is, given the terms of the model access contract (particularly clause A3.38), in both situations raised by Synergy it is consistent with the Code objective for the User to have responsibility to ensure compliance by the Controller of Connection Points.

2377. However, taking account of Synergy's continuing concerns that Western Power may behave unreasonably in negotiating a connection contract with a controller that could result in an unfair commercial allocation of risk, the Authority considers Western Power's obligations should be clarified by inserting an obligation in clause 6.1 for Western Power to negotiate in good faith and use reasonable endeavours to negotiate a Connection Contract with the designated controller.

Required Amendment 46

Clause 6.1 of the ETAC must be amended to include an obligation for Western Power to negotiate in good faith and use reasonable endeavours to negotiate a Connection Contract with the designated controller.

Limitations on Warranty Obligations (clause 18.1)

2378. Western Power did not propose any revisions to clause 18.

2379. In its submission to the first round of public consultation Synergy submitted that the standard access contract does not make it clear what should occur in circumstances where a user is in breach of its warranty or representations as a direct result of Western Power breaching its obligations. Synergy considered that in such circumstances it is not reasonable for a retailer to be liable to Western Power and for Western Power to exercise its rights under clause 27.2 of the standard access contract. Synergy proposed that, in order to clarify the rights of the parties in such circumstances, clause 18.1 should be amended as follows:

> 18.1 If the User* is in breach of the warranty and representation in clause 18.1(a) of this Contract* as a direct result of a breach of the Application and Queuing Policy* or the Code* by Western Power then Western Power may not exercise its rights under clause 27.2 of this Contract* other than to notify the User* of the User*'s Default and the User* will not be liable to Western Power for the breach."

2380. Western Power proposed this could be achieved by amending clauses 18.1(a)(i) and 18.2(a)(i) as follows:

> Clause 18.1(a)(i)
>
> "the User* has complied with the Applications and Queuing Policy* in the Access Arrangement and the requirements in the Code* in respect of its Application* under the Access Arrangement* <u>provided that the User* will not be taken to be in breach of this warranty because of a failure by the User* to comply with the Applications and Queuing Policy* or the Code* which is the direct result of a breach by Western Power* of the Applications and Queuing Policy* or the Code*"</u>
>
> Clause 18.2(a)(i)
>
> "Western Power* has complied with the Applications and Queuing Policy* in the Access Arrangement and the requirements in the Code* in respect of its Application* under the Access Arrangement* <u>provided that Western Power* will not be taken to be in breach of this warranty because of a failure by Western Power* to comply with the Applications and Queuing Policy* or the Code* which is the direct result of a breach by the User* of the Applications and Queuing Policy* or the Code*"</u>

2381. In the Draft Decision the Authority took the view that Western Power's proposed amendments to clauses 18.1(a)(ii) and 18.2(a)(i) adequately dealt with the concerns raised by Synergy and required that such amendments should be made.

> **Draft Decision Amendment 65**
>
> Clause 18.1(a)(i) and 18.2(a)(i) must be amended as set out in paragraph 1448 above.

2382. In response to the Draft Decision, Western Power has accepted Draft Decision Amendment 65 and has amended clause 18.1(a)(i) and 18.2(a)(i) accordingly. Western Power notes that there is a small error in the drafting of clause 18.2(a)(i) in the Draft Decision (paragraph 1448). In the part of the clause which is not being amended the Draft Decision incorporates the wording "its" instead of "the User's*". Western Power has retained the words "the User's*" within clause 18.2(a)(i).

2383. The Authority considers that Draft Decision Amendment 65 has been adequately dealt with.

Compensation for Loss Caused by the Network Operator (clause 19)

2384. Western Power did not propose any revisions to clause 19 of the ETAC.

2385. In its submission to the first round of public consultation, Synergy sought an addition to clause 19 to specify Western Power's liability (to pay compensation to users) for losses caused by Western Power and claimed the current definition of "Direct Damage" is too narrow and one-sided. Synergy argued that, as Western Power is in the best position to manage its risk and its operations when providing services, it should be liable for its actions in relation to the provision of those services.

2386. Synergy drafted a new clause which it considered should be included in clause 19:

19.4 Western Power Liability

(a) If Western Power* is negligent or commits a Default* under this Contract* it must:

(i) repay to the User* any Customer Pass Through Amounts* which the User* is not reasonably able to recover from its Customers* because of the negligence or Default* of Western Power* or because of delay by Western Power* in rectifying or otherwise addressing the negligence or Default*;

(ii) reimburse the User's* reasonable costs, including legal costs, of any reasonable action taken for the purposes of recovering from its Customers* the Customer Pass Through Amounts* referred to in clause 19.4(a)(i);

(iii) reimburse the User's* reasonable Operational Costs* of addressing and mitigating the impacts on its business operations arising from, or in connection with, the negligence or Default* of Western Power*;

(iv) compensate the User* for any loss or damage, including Indirect Damage*, the User* suffers or incurs as a result of, or arising from, any reduction in cash flow caused by Western Power's* negligence or Default*;

(v) reimburse the User* for all expenses and charges (including any Indirect Damage* or other damages, penalties, fines or interest) that the User* incurs as a result of or in connection with a claim by a Customer* under the Competition and Consumer Act*, which the User* is not reasonably able to avoid because of the negligence or Default* of Western Power*;

(vi) not enforce any rights it may have against the User* or the Indemnifier* in respect of a User's Default* that arises due to the negligence or Default* of Western Power*.

(b) The User* must notify Western Power* if the User* intends to take legal action to recover amounts under clause 19.4(a)(i) or to take or not take legal action to defend a claim by a Customer* in relation to clause 19.4(a)(iv) and provide all reasonable details of the actions the User* proposes to take.

(c) Western Power* must, within [7 days] of receiving notification under clause 19.4(b), advise the User* whether Western Power* wishes to take over the proposed legal action, in which case the User* and Western Power* must work co-operatively to enable Western Power* to take over such legal action on behalf of the User*.

Customer Pass Through Amounts* means amounts paid by the User* to Western Power* under the Contract* which the User* would, in the normal course of its business, pass on to its Customers* and the exclusion of Indirect Damage* does not apply.

Operational Costs* means amounts paid by the User* to Western Power* under the Contract* which the User* would, in the normal course of its business, pass on to its Customers* and the exclusion of Indirect Damage* does not apply.

Competition and Consumer Act* means the *Competition and Consumer Act 2010* (Cth).

2387. In the Draft Decision, the Authority noted that Synergy requested a similar amendment during the previous access arrangement review. In its draft decision for the current access arrangement the Authority did not accept that the liability of Western Power for damages as proposed by Synergy was reasonable. The ETAC explicitly limits damages recoverable by a person to direct damage other than where a party commits fraud. This is a deliberate scheme and such limitation of liability is quite common for access contracts relating to large infrastructure with multiple users where indirect losses could be substantial (e.g. if a breach causes power disruption for a period of time, the consequential or indirect damage could include potentially large financial losses, such as lost profits and damage to goodwill for each affected business).

2388. Synergy's proposal would make two exceptions to this limitation – fraud (an existing exception) and deletion of a connection point. Under Synergy's proposal, Western Power would be liable for indirect damages arising from the deletion of a connection point other than in accordance with clause 3.6 of the proposed ETAC, whether this be negligent or deliberate.

2389. In the Draft Decision the Authority considered the existing provisions in the ETAC regarding compensation for losses are reasonable and therefore meet the requirements of section 5.3 of the Code. The Authority considered that making Western Power liable for indirect losses arising from the deletion of a connection point, where such deletion occurs as a result of negligence, is inconsistent with the other provisions of the ETAC. The Authority did, however, consider that such liability is reasonable where the deletion of a connection point other than as allowed for under clause 3.6 is wilful or deliberate.

2390. Consequently, in the Draft Decision the Authority determined that Western Power should be liable for indirect losses arising from the deletion of a connection point, where the deletion of a connection point otherwise than allowed for under clause 3.6 is wilful or deliberate and that a new clause 3.6(e) should be inserted:

3.6(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

2391. This required amendment was included in Draft Decision Amendment 64. As noted in paragraph 2357 above, in its response to the Draft Decision, Western Power has accepted all of the required amendments to clause 3.6 of the ETAC.

2392. In its submission in response to the Draft Decision, Synergy has proposed the same new clause 19.4 as previously submitted. Synergy submits that in order for the ETAC to be reasonable and commercially workable, it must contain a mechanism and clear provisions for retailers and customers to be compensated for all appropriate loss caused by an act or omission of a service provider.

2393. Synergy submits that the current definition of Direct Damage under the ETAC is too narrow and one-sided and that it is not clear what circumstances and conditions would need to apply in order for a retailer to receive compensation for loss suffered due to an act or omission of the service provider. In addition, Synergy submits that Western Power as a monopoly service provider is in the best position to manage its risk and operations when providing services and therefore should be liable for its actions in relation to those services.

2394. The Authority notes that the definition of "Direct Damage" in Schedule 1 of the proposed ETAC is "loss or damage suffered by the person which is not Indirect Damage".

2395. "Indirect Damage" is defined to mean any one or more of:

(a) any consequential loss, consequential damage or special damages however caused or suffered by the person, including any:

(i) loss of (or loss of anticipated) opportunity, use, production, revenue, income, profits, business and savings; or

(ii) loss due to business interruption; or

(iii) increased costs; or

(iv) punitive or exemplary damages,

whether or not the consequential loss or damage or special damage was foreseeable; or

(b) in respect of contractual damages, damages which would fall within the second limb of the rule in Hadley v Baxendale [1854] 9 Exch. 341 (that is, losses which the parties contemplated at the time they entered the contract as arising from a breach); or

(c) any liability of the person to any other person, or any Claim* brought against the person by any other person, and the costs and expenses connected with the Claim*.

2396. The Authority notes there is no definitive definition of indirect or consequential loss in Australian law. Although the definition of "Indirect Damage" in the ETAC is very wide, it appears to reproduce without material variation, the definition in clause A3.2 of the model access contract. As presently drafted, the Indirect Damage exclusion would exclude many types of costs and expenses incurred by a party as a result of the negligence or default of the other party which might otherwise be considered as "normal" losses. However, the clause operates on a mutual basis to limit recovery by each party against the other which, the Authority understands, is not unusual in similar commercial contexts.

Cap on Liabilities (clause 19.5)

2397. Both the Office of Energy and Synergy raised issues in the first round of public consultation in relation to clause 19.5, which limits the liability of Western Power and users to a maximum amount. This limit is the lesser of $80 million and a formula based on the User's number of connection points within each of five categories of connection points.

2398. In its submission, the Office of Energy noted that, in practice when applied to retailers, the formula is unlikely to return a value of less than $80 million. The Office of Energy states that, as no sub-limits are set for a User's liability in respect of individual events at the various types of connection points, the maximum liability accruing to a User in respect of a liable event at any of its connection points will always be the annual liability cap set by clause 19.5(b), namely, $80 million.

2399. The Office of Energy submits that if a retailer wishes to effectively pass through all liabilities associated with all customer connections, it would need to ensure all its customers were insured to the upper limit of potential liability for damage to the network, being $80 million (or as otherwise determined under 19.5(b)). The Office of Energy considers this is not feasible for small connections and, while retailers may require small customers to indemnify them, they will not check for insurance in most cases. In any event, the Office of Energy considers it would be unrealistic to expect many small customers to insure against an $80 million liability.

2400. The Office of Energy notes that, for small connections, it appears retailers enter into supply contracts on the assumption that the plausible liability associated with those customers is much less than $80 million. However, the Office of Energy considers retailers have shown themselves unwilling to make the same assumption in relation to small customers with renewable energy systems, because grid connection of small renewable generation equipment is a relatively new phenomenon.

2401. The Office of Energy considers that Western Power should be encouraged to estimate the upper limit of the damage to the network that may arise from a single liable event for the main different classes of connections, including bi-direction service customers and that these estimates should then be used to establish sub-limits to liability for individual events in each connection class, under the ETAC.

2402. Synergy also made submissions on clause 19.5 and noted that, in its experience, insurers will extend cover to retailers for the acts or omissions of the retailer only and not those of third parties. Synergy has been unable to determine how a retailer, through its own actions, could cause $80 million dollars of damage to the network, especially under a regime where the network operator has the obligation to inspect, maintain and approve the connection of equipment to the network. In the context of assigning risk to the party best able to manage it, Synergy does not understand the economic basis that Western Power has used to determine this value. Therefore, in light of clause 6.2(e), Synergy submits that it is reasonable for the standard access contract to specify a different maximum cap for generators and retailers and that the Authority, in assigning risk to the party best able to manage it, must be satisfied with the methodology used to determine these amounts. It is Synergy's preference that the methodology is subject to public consultation as part of the Authority's determination of the proposed revised access arrangement.

2403. The Authority sought further information from Western Power in regard to the practicalities of amending the current caps on liability. Western Power responded as follows:

- Synergy's submission does not acknowledge the fact that the way the cap is determined is by aggregating the amounts referred to in clause 19.5(b)(ii). The $80 million is a further level of protection for the User.
- Synergy's submission implies that the User should not take responsibility for the acts or omissions of their customers. However such a lack of responsibility would be inconsistent with the structure of the Western Australian electricity industry, which is based on Users having contracts with

the end-use customers. Users therefore need to be responsible for the acts or omissions of end-use customers because only the Users have the contractual right to control how the end-use customers behave. Western Power cannot regulate what end-use customers do and does not have contractual rights to claim damages from the end-use customers if they do not comply with the standards noted in the ETAC.

- The liability allocation in the ETAC (i.e. where the User takes responsibility for its customers) is the same as that in other jurisdictions where the infrastructure owner does not have a contractual relationship with the customer – specifically, New South Wales (Jemena Access Arrangement) South Australia (Envestra Access Arrangement) and Queensland (Envestra and APT Access Arrangements). Furthermore, the liability cap ($80 million) is more generous to the User than the caps which apply in these jurisdictions.
- In the APT Access Arrangement for its Queensland Distribution Network the User gives an uncapped indemnity against any damages/losses flowing from the User's breach of its agreement with the Service Provider and against any damage to the network caused by the User or any of its customers (clause 14.5).
- In the Jemena Access Arrangement, the User provides various indemnities to the Service Provider, including in respect of overrun and failure to cease take of gas when required by the Service Provider (both of which are matters within the control of the end-use customer). There is no cap on liability for these indemnities.
- Each of the above arrangements and the liability regimes within them have been approved by the AER within the last 24 months.
- The potential certainly exists for a User to cause Western Power $80 million in damage over the course of a year – noting that the $80 million is an annual aggregate cap. If over the course of a year there were a large number of incidents due to a User's poor management of the actions of its customer base, this scenario could well arise. That said, Western Power considers that a User who was effectively managing the behaviour of its end-use customers should not find itself in this position.
- In respect of Synergy's assertion that it is reasonable for the access contract to specify a different maximum cap for generators and retailers, Western Power notes that clause 19.5(b)(ii) does specify different caps for generators and retailers. However where a party to the ETAC is both a generator and a retailer then these individual subcaps need to be combined, which is what is effected by clause 19.5(b)(i).
- Synergy itself proposed a cap of $60 million at the time of the second access arrangement review. There is no developed reasoning in Synergy's submission as to why this cap is inappropriate, other than the clear indication that Synergy does not wish to take responsibility for the acts or omissions of its customers.

2404. In response to the Office of Energy's submission that Western Power should be encouraged to estimate the upper limit of damage to the network that could arise from a single event for the main different classes of connections and then use this to determine sub-limits for individual events, Western Power responds as follows:

- It is not aware of any evidence that the current liability regime is a barrier to entry. There is no evidence similar regimes in the New South Wales, Queensland and South Australian gas industries act as a barrier to entry;

- A variation to the liability caps, and consequent increase to Western Power's risk profile, will in turn impact the cost of its insurance and this will need to be reflected in tariffs;
- If Western Power is required to absorb the cost of damage to its network then, to the extent insurance proceeds are not available, this cost of repair should also be reflected in tariffs. Otherwise, there is an adverse impact on Western Power's return due to the acts of Users and Western Power is being provided with no additional recompense for absorbing this risk (as compared to what would be expected to occur in a competitive market).
- Western Power is not aware of any regulatory regimes where sub-limits for individual classes of events are determined in the manner contemplated.
- Further, Western Power is of the view that a regime where liability limits are set by reference to specific events is both unwieldy and impractical, and speculates that this may be why such regimes are not, to its knowledge, in use.
- To determine a liability limit for a single event in the different classes of connection would require Western Power to undertake a comprehensive risk assessment of the maximum potential damage that could arise in each class of connection and then determine an appropriate liability cap for that class. This would require a comprehensive analysis of the type of equipment within such connections and a determination of the possible events that could arise and cause such damage. This would in turn require both engineering analysis and also analysis with Western Power's insurers and brokers. The analysis is not simply a matter of considering the potential impacts arising from the operations of generators on the one hand and customers on the other. The potential impact of a generator will depend upon the type of generator it is and its location in respect of the rest of the network (which will in turn determine the potential consequences of an event affecting it). This may also be the case with customers. Therefore it will not be possible to identify one reliable cap per type of event.

2405. In the Draft Decision the Authority noted it had considered clause 19 at the last access arrangement review. In its final decision in relation to the current access arrangement, the Authority determined that the maximum liabilities proposed by Western Power were unreasonable in that, for users that are retailers with many connection points, the maximum liability of the user may be an amount in excess of any reasonably conceivable level of damages to the network or Western Power. As a result the Authority did not consider Western Power's proposal at the last access arrangement review was consistent with the requirements of the Access Code and required there be a cap on the maximum liability of users.

2406. The Authority notes Western Power's comments and agrees there has been no significant change in circumstances since the last review that would justify a change to the upper limit of liability. Neither Synergy nor the Office of Energy have provided further comment or reasons for the change in their respective submissions in response to the Draft Decision. In view of Western Power's submission referring to similar liability regimes recently approved by the AER in other states, and in the absence of direct evidence from small retailers regarding their inability to obtain insurance up to the level of the cap, the Authority is of the view that it does not have sufficient evidence to support a finding that the amount of the liability cap is commercially unworkable.

Western Power Invoices (clause 8.1 and 8.6)

2407. Western Power has proposed amendment of the definition of 'payment error' in Schedule 1 to address all of the situations covered by clause 8.6, and the insertion of new clauses 8.6(f) and 8.6(g) to allow clause 8.6 to operate effectively. The proposed revisions are as follows:

> 8.6(f) Where a Payment Error* is an error as a result of which the amount set out in a Tax Invoice* is less than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the Due Date* of the Tax Invoice*.
>
> 8.6(g) Where a Payment Error* is an error as a result of which the amount set out in a Tax Invoice* is more than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the date the User* has paid the total amount of the Tax Invoice* in full.
>
> Payment Error means
>
> (a) any underpayment or overpayment by a Party* of any amount in respect of a Tax Invoice*; or
>
> (b) any error in a Tax Invoice* (including the omission of amounts from that Tax Invoice*, the inclusion of incorrect amounts in that Tax Invoice*, calculation errors in the preparation of a Tax invoice* or a Tax Invoice* being prepared on the basis of data which is later established to have been inaccurate).[~~means any underpayment or overpayment by a Party* of any amount in respect of a Tax Invoice~~*.]

2408. Synergy's submission to the first round of public consultation noted that it had discussed these amendments with Western Power and that its understanding was that the changes were required to deal with circumstances where Western Power has not invoiced a User for several years for a connection point, as typically these connection points have not also had a meter reading for several years. Consequently, when Western Power subsequently discovers such a connection point it is seeking the ability to make these connection points subject to Synergy's access contract and to invoice Synergy for past charges.

2409. Synergy considered Western Power's proposed changes were designed to give effect to such an outcome and do not appear to deal with the genuine circumstances associated with an under or over payment. That is, there is no limitation or sunset provision limiting when Western Power can issue an invoice and demand payment for charges that may or may not have been incurred several years ago. Synergy considers this situation also creates difficulties for a retailer with respect to reconciling such invoices, especially in circumstances when the retailer does not have an accurate list of the connection points subject to its access contract, and where Synergy is limited in its ability to pass on these amounts under the Code of Conduct and the *Energy Operators Powers Act*.

2410. Synergy submitted that such an approach was unreasonable and does not form the basis of a commercially workable access contract. Therefore, Synergy submitted that clause 8.6 should remain unchanged from the current access arrangement and the following changes should be made to clause 8.1 and the definition of "Payment Error" to clarify the minimum conditions and operation of clause 8.6:

- Clause 8.1 – to contain a provision that makes it clear Western Power must not issue a tax invoice in respect of amounts that would otherwise have been payable under the standard access contract later than 12 months from the date those amounts are payable.

- Payment Error – to be defined as any underpayment or overpayment by a party of any amount in respect of a tax invoice for any amount payable by the User under the standard access contract.

2411. Synergy considered the fundamental problem that gives rise to these types of issues lies in Western Power's inability to provide Users with an accurate list of connection points on the User's access contract.

2412. Synergy requested that Western Power provide an accurate list of connection points in an access contract (as it is fundamental to a retailer's business and hence to a commercially workable access contract).

2413. Synergy noted that it has been seeking an accurate list of the connection points on its access contract and that Western Power continues to have difficulty providing an accurate list. A retailer may only supply electricity to a customer through a connection point on its access contract. Without such a list, it is not possible for a retailer to determine at any given point in time who is taking electricity on its account. Unless a positive obligation to provide an accurate list of connection points on an access contract is imposed, Synergy submits Western Power's proposed changes to the payment error terms under the standard access contract are unworkable as they provide Western Power with the ability to retrospectively, several years later, make Synergy liable for access charges for connection points Western Power may have initially omitted to list on Synergy's access contract.

2414. The Authority noted in the Draft Decision that similar issues were considered by the Authority at the last access arrangement review and the Authority's final decision for the current access arrangement required a number of amendments to require Western Power to update the metering database and provide reasonable information to users.

2415. The following amendments were made to clause 3.7:

> 3.7(a) Unless the Parties* otherwise agree, Western Power must record the information referred to in Part 1 of Schedule 3, with respect to each Connection Point*, in the Connection Point Database*.
>
> 3.7(b) Subject to clauses 3.7(g) and 3.7(h), Western Power* must update the information contained in a Connection Point Database* following any variation made under this clause 3.
>
> 3.7(c) Upon request by the User* for information referred to in the Connection Point Database*, Western Power* will provide to the User* the most up-to-date version of that information.
>
> 3.7(i) The Parties* must notify each other of any errors discovered in the Connection Point Database* as soon as reasonably practicable after becoming aware of the error.
>
> 3.7(j) Western Power* must amend any error in the Connection Point Database* as soon as reasonably practicable after becoming aware of the error, provided that if Western Power* becomes aware of an error otherwise than by notice from the User* under clause 3.7(i), no amendment shall be made until Western Power* has given notice to the User* of the error.

2416. In the Draft Decision, the Authority noted it considered these amendments provide adequate protection to ensure the connection point database is updated in a timely and accurate manner.

2417. In its submission in response to the Draft Decision, Synergy notes it has over 900,000 connection points subject to its ETAC and considers it needs the following to enable it to bill and provide services to its customers:

- clear and workable obligations imposed on the network operator for adding and removing connection points to ensure that the connection point database is accurate and subject to change only in accordance with established rules and procedures;
- timely updating of the database to ensure that a retailer is able to bill its customers without delay;
- an automated mechanism for changing the database; and
- an ability to recover any loss or damage that Synergy suffers as a result of the network operator not meeting these obligations.

2418. Synergy submits that the standard access contract is deficient because:

- it does not contain any real or "workable" obligation on the network operator to update the information associated with connection points accurately and on a timely basis;
- it puts no "workable" obligation on the network operator to maintain an accurate database;
- it does not allow Synergy to recover damages for loss it suffers as a result of the network operator failing to add or remove connection points notwithstanding a request.

2419. As set out in paragraphs 2414 to 2416 above, the Authority considers the amendments made at the last access arrangement review are generally adequate to ensure that Western Power is required to update connection point data and provide accurate records to users as required. Synergy's concerns in relation to the physical processes for updating the database are not a matter for the ETAC. The matters raised by Synergy in relation to recovery of loss or damage are considered in paragraphs 2385 to 2396.

2420. However, taking account of the submissions from Synergy, the Authority considers that the requirements for timeliness in respect of updating the databases and providing information to users should be strengthened by amending each of the sub-clauses of clause 3.7 to require Western Power to act "as soon as reasonably practicable".

Required Amendment 47

Each of the sub-clauses in clause 3.7 of the electricity transfer must be amended to require Western Power to act "as soon as reasonably practicable".

2421. The Authority queried Western Power regarding Synergy's concerns that the proposed changes in relation to payment errors were required to deal with circumstances where Western Power had not invoiced a User for several years for a connection point.

2422. In relation to the intention of the amendment, Western Power notes the explanation it provided on page 319 of its access arrangement information:

> "The definition of "payment error" requires amendment to cover all of the situations covered by clause 8.6. The present definition is limited only to payment errors where the invoiced amount was correct but not paid in full or overpaid. It does not cover the situation where the tax invoice itself contained the wrong amount because it was calculated using incorrect data."

2423. In relation to Synergy's concern that Western Power would be able to invoice Synergy for charges dating back several years, Western Power noted:

- clause 8.6(d) states that Payment Errors may only be corrected within 18 months of when the error was made; and
- clause 8.6(e) provides that where a Payment Error has occurred as a result of an error in the data used to calculate the Charges "the Party who was underpaid or who made an overpayment (as applicable) is entitled to an adjusting payment only for the Payment Errors that occurred in the Accounting Periods that were within the 12 month period preceding the date that the Payment Errors were notified by one Party to the other".

2424. In summary, Western Power does not consider the proposed amendments give Western Power an entitlement to invoice a User for unread connection points and considers the combined effect of clauses 8.6(d) and 8.6(e) results in a 12 month limitation period as requested by Synergy.

2425. As noted in the Draft Decision, the Authority has considered the matters raised by Synergy, and the responses provided by Western Power. The Authority considers that Western Power's proposed revisions to clause 8.6 and the definition of payment error are reasonable and necessary to more accurately define when a payment error is taken to have occurred.

Payment Duration (clause 8.3)

2426. Clause 8.3 of the standard access contract requires a User to reconcile and pay Western Power's invoices within 10 business days of receiving the invoice. Western Power has not proposed any revisions to clause 8.3 but Synergy has raised some concerns.

2427. In its submission to the first round of public consultation, Synergy considered a 10 business day period may be reasonable and workable for smaller users and retailers but notes that the invoice it receives from Western Power contains more than 8 million transactions that need to be reviewed, reconciled and paid and that it is not feasible to do this within 10 business days. Synergy submits that payment terms for access charges of 20 business days are reasonable and consistent with industry practice but has provided no examples to support this.

2428. Western Power provided the Authority with a summary of payment periods for other Australian gas and electricity legislation and access arrangements. It also noted the provisions of *the National Electricity (Retail Support) Amendment Rules 2010* (**National Rules Amendment**) which, although yet to come into effect, will regulate the periods within which retailers are required to pay network charges to a distributor. In these rules the due date for payment is defined as being 10 business days from the date of issue specified on a statement of charges.

2429. In the Draft Decision, the Authority confirmed the information provided by Western Power and determined that the current payment duration of 10 business days is consistent with industry practice. Consequently, the Authority considered that the payment terms in clause 8.3 are reasonable and do not require change.

2430. In its submission in response to the Draft Decision, Synergy has requested the Authority to reconsider its decision and submits the following:

- The Authority has not recognised that the National Rules Amendment are underpinned by a robust and reliable framework to ensure the reliable communication of connection point and metering information and data between participants to give effect to a payment duration of 10 business days.
- A similar robust communication framework does not exist in Western Australia. It therefore takes Synergy longer to reconcile the connection point data, metering data and associated charges. This also means that sometimes Synergy is not actually able to physically receive, process and perform the reconciliation of network charges.
- Synergy submits that such a framework is not currently available in the Communication Rules approved by the Authority. Such a framework would be a supplementary matter contemplated under clause 5.27 of the Access Code and clause 23 of the proposed standard access contract.
- The proposed National Rules Amendment provides for the network operator to directly issue a bill to a consumer for network charges. Synergy submits that such an arrangement would significantly reduce the liability on retailers and ease the burden on retailers of reconciling and recovering network charges. Synergy notes that the access arrangement approved by the Authority does not provide for direct billing by the network operator.
- Synergy notes that it operates in a market that differs from the national regime. Synergy has only one distributor with which it has an access contract and therefore all of its connection points are contained within a single monthly invoice. Alternatively, Eastern States retailers have a number of distributors that invoice them and it is unlikely that all of their connection points will be invoiced simultaneously and require payment within the same 10 day period. Synergy submits that its position of having to reconcile in excess of 900,000 connection points within a 10 day period is a situation in Australia that is unique to Synergy.

2431. The Authority has considered the matters raised by Synergy below.

Communication Framework

2432. Synergy has asserted that its invoice payments are not supported by a robust communication framework, as exists in other States, and that such a framework is not currently available in the Communication Rules approved by the Authority.

2433. The Authority notes that the Communication Rules set out high level objectives for communication rules between Western Power and a code participant. The Communication Rules provides high level details about the methods (e.g. the network operator's web portal and xml based electronic business-to-business transactions) and protocols for communication between Western Power and a Code participant. The Communication Rules are not prescriptive in terms of the actual implementation and workability of communication frameworks between Western Power and a code participant.

2434. The Authority considers that Synergy has not provided sufficient evidence to allow it to assess:

- the practical shortcomings of the communication framework in Western Australia compared to equivalent rules in other States that prevent it from achieving a payment duration of 10 business days;
- what efforts Synergy has made, in consultation with Western Power, to address issues with the communication framework in order to better facilitate a payment duration of 10 business days;
- how or why Synergy considers that problems with the communication framework can or should be addressed through the access arrangement, rather than through negotiation between Synergy and Western Power.

2435. The Authority considers that the Communication Rules provide sufficient direction about communication objectives, methods and protocols between Western Power and a Code participant. In any case, issues of implementation and workability of the resulting communication frameworks are not a matter for the access arrangement review.

Direct billing

2436. Synergy notes that the proposed National Rules Amendment provides for the network operator to directly issue a bill to a consumer for network charges.

> **6B.A2.2 Direct customer billing and energy-only contracts**
>
> (a) Where a *Distribution Network Service Provider* and a *shared customer* agree that the customer will be responsible for paying *network charges* directly to the *Distribution Network Service Provider* (a direct billing arrangement), the *Distribution Network Service Provider* may issue a bill to that customer for any or all of the *customer connection services* provided to that customer's premises.
>
> (b) The *Distribution Network Service Provider* must notify the *retailer* of the direct billing arrangement as soon as reasonably practicable after commencement of the agreement.
>
> (c) A *retailer* has no liability to pay *network charges* that have been, or are to be, billed to the *shared customer* under a *direct billing arrangement*.
>
> (d) Where a *retailer* and a *shared customer* enter into a contract for the sale of electricity only, the *retailer* must notify the relevant *Distribution Network Service Provider* as soon as reasonably practicable after commencement of the contract.[641]

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[641] AEMC 2012, National Electricity (National Energy Retail Law) Amendment Rule 2012, accessed from http://www.aemc.gov.au/Media/docs/Binder1-84bb7f5b-d82f-4484-851b-5e3c662c5f84-1.PDF on 12 July 2012. The current version of the National Electricity Rules does not include changes made by the National Electricity Amendment (National Energy Retail Law) Rule 2012. This rule will be consolidated in the next version of the National Electricity Rules as soon as practicable.

2437. The Authority notes that a connection service in the National Electricity Rules is defined as:

> An *entry service* (being a service provided to serve a *Generator* or a group of *Generators*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*) or an *exit service* (being a service provided to serve a *Transmission Customer* or *Distribution Customer* or a group of *Transmission Customers* or *Distribution Customers*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*).

2438. Synergy considers the ability for network operators to directly issue a bill to a consumer for network charges would significantly reduce the liability on retailers and ease the burden on retailers of reconciling and recovering network charges.

2439. The Authority notes that the proposed National Rules Amendment is still to come into effect so is not relevant to the current payment performance of retailers in the NEM. Furthermore, it would seem unlikely that the intention of such an amendment is to enable network operators to bill small retail customers direct and it is more likely intended to apply to larger customers, so would not significantly reduce the number of transactions required to be reconciled by a retailer.

Market structure

2440. Synergy contends that the industry examples of payment terms from other energy markets in Australia are not relevant because the structure of the market that Synergy operates in differs to those in other States. In particular, Synergy notes that it has the largest number of transactions to reconcile from a single distributor.

2441. The Authority notes that residential and small business customers are typically billed bi-monthly which would suggest that the monthly invoice to Synergy would include significantly less than 900,000 connection points.

2442. The Authority notes the AER's report "State of the energy market-2011"[642] states that AGL Energy, Origin Energy and TRUenergy supply the bulk of small customers in the eastern mainland states, which would make them at least equivalent, and probably much larger, than Synergy in terms of customer numbers. Although these retailers may receive invoices from a number of network operators, given that the NEM network operators generally have similar invoicing processes, the work required to process and reconcile transactions from each network is likely to occur during similar periods.

2443. In any case, the Authority notes that clause 8.1(d) of the standard access contract provides that:

> (d) Notwithstanding clause 8.1(a), the Parties* may, by mutual agreement, implement a different system of invoicing to that stipulated in clause 8.1(a) including, for example, issuing two or more Tax Invoices* per Accounting Period*, and separate invoicing for different classes or groups of consumers, Connection Points* or Services*.

2444. Synergy could negotiate an alternative invoicing arrangement with Western Power if it is having difficulties processing and reconciling all of its connection points within a

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642 AER 2011, State of the energy market-2011, accessed from http://www.aer.gov.au/sites/www.aer.gov.au/files/State%20of%20the%20energy%20market%202011%20-%20complete%20report.pdf on 8 August 2012.

10 business day period. These alternative arrangements could potentially include Western Power issuing several invoices per accounting period.

Authority's Final Decision

2445. The Authority notes that the Model Standard Access Contract requires that, unless the Authority considers that a different value will better achieve the Code objective, 10 business days should be used as the due date for payment.

2446. As discussed above, the Authority does not agree with the concerns raised by Synergy in relation to differences between Western Australia and the NEM and notes that the current access arrangement includes provision for alternative invoicing arrangements, which may assist Synergy with the difficulties it considers it is encountering.

2447. Furthermore, the Authority does not consider that Synergy has provided adequate evidence to demonstrate that it has difficulty in meeting the 10 business day rule, particularly given that this payment period has been in place since the first access arrangement was approved in 2007. Although Synergy submitted that 'sometimes Synergy is not always actually able to physically receive, process and perform the reconciliation of network charges' (p. 17 of Synergy submission), it has not provided any further supporting information, including:

- how frequently Synergy is unable to meet the 10 business day period in practice;
- by how much Synergy generally exceeds the 10 business day period;
- the steps Synergy has taken to ensure that it is able to meet the 10 business day period (for example, improving systems, engaging additional resources, renegotiating arrangements with Western Power);
- the consequences for Synergy and others when it fails to meet the 10 business day period.

2448. For these reasons, the Authority considers that the payment terms in clause 8.3 are reasonable and do not require change.

Security for Charges (clause 9)

2449. Western Power has proposed amendments to clause 9, including insertion of a new clauses 9(c), which will require users, on request, to increase security where the existing security given to Western Power at that time is no longer equal to the charges for two months services; and insertion of a new clause 9(e) to manage security in situations where a parent company's circumstances change. Western Power's proposed amendments are set out below.

9. Security for Charges*

(a) Subject to clause 9(c), if Western Power* determines at any time during the Term* that either or both of the User*'s or the Indemnifier*'s technical or financial resources are such that a Reasonable and Prudent Person* would consider there to be a material risk that the User* will be unable to meet its obligations under this Contract*, then

(i) Western Power* may require the User* to within 15 Business Days* nominate which of the User* or the Indemnifier* (**"Nominated Person*"**) is to provide ~~the following~~ security; and

(ii) within 15 Business Days* of the User*'s nomination under clause 9(a)(i), ~~then require~~ the Nominated Person*, at the User*'s election, must either ~~to~~:

(A) pay to Western Power* a cash deposit equal to the Charges* for two months' services; or

(B) provide an irrevocable and unconditional bank guarantee or equivalent financial instrument in terms acceptable to Western Power* (acting as a Reasonable and Prudent Person*), guaranteeing or otherwise securing the Charges* for two months' services; or

(C) if Western Power* is satisfied, as a Reasonable and Prudent Person*, that the User*'s parent company's financial and technical resources are such that the User's* parent company would be able to meet the User*'s obligations under this Contract* (including because the User*'s parent company meets at least one of the credit ratings given in clauses 9(b)(i) and9(b)(ii)), procure from the User*'s parent company a guarantee substantially in the form set out in Schedule 8.

(b) If the User* or the Indemnifier* has an unqualified credit rating of at least:

(i) BBB from Standard and Poor's Australia Pty Ltd; or

(ii) Baa from Moody's Investor Service Pty Ltd,

and provides evidence to this effect to Western Power*, then Western Power* is not entitled to determine under clause 9(a) that the User*'s financial resources are such that there would be a material risk that the User* will be unable to meet its obligations under this Contract*.

(c) If any security held by Western Power* under clause 9(a)9ii)(A) or 9(a)(ii)(B) at any time is not equal to the Charges* for two months' services, then the Nominated Person* must, within 15 Business Days* of a written request by Western Power* to the User*:

(i) if the security is a cash deposit under clause 9(a)(ii)(A), provide Western Power* with an additional cash payment to increase the security so that it is equal to the Charges* for two months' services; or

(ii) if the security is a guarantee under clause 9(a(ii)(B), replace the guarantee with another guarantee (that is in accordance with clause 9(a)(ii)(B) in an amount that is equal to the Charges* for two months' services.

(d) If any security held by Western Power* under clause (A) or (B) is called upon by Western Power* or if that security ceases to be enforceable for any reason (including due to expiry of the security) then within 15 Business Days* the Nominated Person* must provide replacement security to Western Power* complying with the requirements of clause 9(a)(ii).

(e) Where a guarantee has been provided to Western Power* by the User*'s parent company but Western Power* ceases to be satisfied, as a Reasonable and Prudent Person*, that the criteria in clause 9(a)(ii)(C) are met then by notice to the User* Western Power* may require the provision of a new form of security

> complying with the requirements of clause (A) or (B) which security must be provided within 15 Business Days* of service of Western Power*'s notice.

2450. In its submission to the first round of public consultation, and in response to the Draft Decision, Synergy requests amendments to clause 9 to ensure only breaches of material contract obligations are acted upon and proposes clause 9(a) should be amended as follows to clarify the materiality associated with a User not meeting an obligation under the standard access contract:

> 9(a) Subject to clause 9(b), if Western Power* determines at any time during the Term* that either or both of the User*s or the Indemnifier*s technical or financial resources are such that a Reasonable and Prudent Person* would consider there to be a material risk that the User* will be unable to meet its material obligations under this Contract*…

2451. In its submission to the first round of public consultation, ERM Power accepts Western Power's proposed modifications to security requirements (to cover two months service charges) as long as it is managed to avoid it becoming an administrative burden. ERM Power suggests this could be avoided by a request only being generated when the security amount falls below one month's service charge. ERM notes that a security is supposed to be a nominal amount and is not a guarantee to recover lost revenue.

2452. ERM Power also raises concerns with the proposed amendments, which require replacement security to be provided if the security is called on or if that security ceases to be enforceable for any reason, including as a result of the expiry of the security. ERM Power states that it believes a security is generally called upon in circumstances of hardship and an additional burden of replacing the security would not be welcome and may not be successful. ERM Power considers that if the security ceases to be enforceable then a remedy ought to be found and it is unlikely this will just be providing a replacement security.

2453. Landfill Gas and Power considers that Western Power should also pay interest on cash security deposits, in common with the practice of the IMO.

2454. In the Draft Decision the Authority took the view that it is unnecessary and confusing to insert the word "material" to clause 9(a) as suggested by Synergy. Among other things, a primary purpose of clause 9(a) is to specify the 'threshold test' to be applied by Western Power in determining whether or not Western Power will require security from a user (or indemnifier). It is not, and does not require, an analysis of which "obligations" Western Power needs to consider in making such a determination.

2455. Synergy's submission in response to the Draft Decision states that it does not understand the rationale for this objection. Synergy considers that, without the inclusion of this materiality threshold, a breach of an immaterial contractual obligation can trigger "draconian consequences". Synergy also considers the concept of materiality is necessary in this context to create commercial workability.

2456. The Authority notes that the existing clause 9 appears to be largely based on clause A3.51 of the model access contract. Contrary to Synergy's submission, Western Power's right to require security under clause 9 is not contingent on a breach of the access contract. Rather, the provision allows Western Power, at any time during the term of the agreement, to determine that the user's (or indemnifier's) financial or technical resources are such that a reasonable and prudent person would consider there to be a material risk that the user will be unable to meet its obligations under the contract. The Authority considers the focus of the clause is on Western Power's assessment of the user's financial or technical resources to meet all of "its obligations under the contract" as a whole. It is difficult to see how a failure to meet a minor obligation could of itself give rise to a concern about the user's financial or technical resources. In any event, protection is given to the user against unreasonable action by Western Power by the requirement in the clause that Western Power must act as a reasonable and prudent person in assessing the financial or technical resources of the user.

2457. For these reasons, the Authority remains of the view that Synergy's proposed amendment is not necessary in order for the clause to comply with clause 5.4(a) of the standard access contract.

2458. The Authority notes ERM Power's concern that the proposed modifications should be managed so as to minimise administrative costs and agrees that it is reasonable that requests should only be generated by Western Power in circumstances where the security falls below a specific threshold. The Authority is also concerned that the operation of the existing clause 9 is unclear in a couple of other material respects. In particular:

- it is not clear from clause 9(a) or clause 9(c) which "two months' services" the charges are referrable to. A reference point is important where the charges are not fixed. Without a reference point, the applicable "two months" period in both clauses is ambiguous; and
- clause 9 does not specify the circumstances in which Western Power can draw or call on the security and whether the security is refundable, or returnable (as the case may be), to the relevant user (or indemnifier) when the contract is at an end.

2459. In response to the Authority's concerns about the drafting of the existing clause 9, Western Power noted that the current clause is based on the model ETAC which does not expressly address these matters.

2460. Western Power submits that, in the absence of an express statement as to when it can draw on security, it may draw on security to recover any amount due to it under the contract but unpaid. Western Power notes this is consistent with the approved form of parent company guarantee in Schedule 8 of the ETAC. It is also consistent with the terms of clause 9(a), which refers to the user meeting all of its obligations under the ETAC, not limited to specific obligations.

2461. However, Western Power proposes to address the issues raised by the Authority by adding paragraphs (f) to (h) below to clause 9:

> (f) Upon the expiry or termination of this Contract* and receipt by Western Power of all amounts due by the User* to it under this Contract* Western Power* will return to the User* any security provided under this clause 9 which is still held by Western Power*.
>
> (g) Western Power* may call upon a cash deposit or bank guarantee (or equivalent financial instrument) provided to it under this clause 9 if an amount due by the User* to Western Power* under this Contract* is not paid by the due date for payment of that amount or, where this Contract* does not specify a due date for payment, is not paid within 10 Business Days of Western Power* issuing a notice to the User* requiring payment of the amount.

(h) In this clause 9, a reference to the Charges* for two months services means Western Power*'s reasonable estimate of the Charges* which will be incurred by the User* for the Services* provided under this Contract* in the next two calendar month period from the end of the next Accounting Period* (that is, from the end of the Accounting Period* which expires after the Accounting Period* in which the User* is notified of the current level of security it is required to provide)."

2462. The Authority is of the view that Western Power's proposed additional clauses 9(f), (g) and (h) are reasonable and provide clarity to the operation of clause 9, reducing the risk of disputes about the parties' rights under this clause. Subject to consideration of submissions from users and other interested parties, the Authority proposes to require these clauses to be included in the ETAC.

Required Amendment 48

An amendment is required to the ETAC to reflect the amendments set out in paragraph 2461 above.

2463. The Authority notes ERM Power's point that it may not be possible to provide replacement security in circumstances of hardship, but that is not relevant to the determination of a standard ETAC, and further, is not a valid reason for a user to be in breach of the obligation to provide such security under clause 9(a).

2464. In the Draft Decision, the Authority agreed that it would be reasonable for Western Power to pay interest on cash security deposits and that this should be specified in the ETAC.

2465. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 67

An amendment is required to the ETAC to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

2466. In response to the Draft Decision, Western Power' set out in the amended access arrangement information three reasons for not accepting this requirement:

- The industry standard is to not receive security in the form of cash deposits, but where cash deposits are accepted there is generally not an obligation to pay interest;
- The requirement may have legal and regulatory implications for Western Power under the *Corporations Act 2001* (Cth) (**Corporations Act**) and the *Banking Act 1959* (Cth) (**Banking Act**); and
- The requirement would result in Western Power incurring additional costs exceeding interest paid.

2467. The Authority considers that the cash security deposit (and interest accruing on the cash security deposit) should be analysed as money held on constructive trust for the following reasons:

- Western Power may only require security in certain limited circumstances as set out in clause 9(a) of the ETAC. If Western Power requires security, then the user may decide which of the user or the indemnifier is to provide security, and the form of the security: cash deposit, bank guarantee (or equivalent financial instrument) or parent company guarantee.

- The purpose of the security is to secure payment of amounts due under the ETAC.
- Proposed clause 9(g) of the ETAC specifies when Western Power may call on a cash deposit or bank guarantee (or equivalent financial instrument). Western Power may do so if the user does not pay an amount by the due date for payment, or where the contract does not specify a due date for payment, the amount is not paid within 10 business days of Western Power issuing a notice to the user requiring payment.
- Proposed clause 9(f) of the ETAC states that upon the expiry or termination of the contract and receipt by Western Power of all amounts due by the user under the contract, Western Power will return to the user any security provided under clause 9 that is still held by Western Power.
- Proposed clause 9(f) is consistent with a well-established principle of constructive trust law: if a person makes a payment to another person for a certain purpose, and the person takes the money knowing that it is for that purpose, the money must be applied for that purpose or be repaid. In this scenario, to the extent that Western Power is not entitled to call on a security, the money remains the property of the user. In the Authority's view, this applies equally to the original cash security amount as to interest accruing on the cash security amount.

2468. Western Power's first reason for not accepting the required amendment is that the industry standard is not to receive security in the form of cash deposits. The Authority considers the relevant issue is not whether there is an industry standard, but rather the legal consequences of the security arrangement actually entered into. As outlined above, the Authority considers the cash security amount will be subject to a constructive trust. Further, the Authority is aware that, outside of the electricity industry context, a cash security deposit is a recognised form of security for performance (for example, in the property market) and that it does not usually give rise to any practical difficulties for a secured party.

2469. Western Power's second reason for not accepting the required amendment is that the requirement to pay interest on cash security deposits provided by users would have implications under:

- Section 911A of the Corporations Act (which requires a person carrying on a financial services business to hold an Australian financial services licence);
- Section 766E of the Corporations Act (which applies where a person provides a custodial or depository service to another person); or
- Section 8 of the Banking Act (which requires a body corporate to be an authorised deposit-taking institution before it is permitted to carry on a banking business in Australia).

2470. The Authority is of the view that the matters raised by Western Power may be based on the mistaken premise that it will become an entity that pays interest on customer deposits. Western Power would not be required to register as an Authorised Deposit-taking Institution under the Banking Act. Western Power would pay funds received from cash security deposits pursuant to its contracts to its bank. Western Power's bank would pay interest on the cash security deposit.

2471. In relation to section 911A of the Corporations Act, even if Western Power were considered to be providing financial services, it would not be doing so to the extent of carrying on a financial services business. This is because Western Power has effectively conceded that cash security deposits do not constitute a significant part of its business activities (at page 241 of the amended access arrangement information):

> "Cash deposits are not a common form of security received. Currently, Western Power holds six cash security deposits totalling approximately $700,000 and earning approximately $30,000 of interest income per annum. Western Power note that the number and value of cash on deposit held by Western Power varies throughout the year, however the current scenario is a fair reflection of the average amounts held."

2472. Section 766E of the Corporations Act specifies when a person provides a custodial or depositary service to another person. This section is qualified by regulation 7.1.40 of the Corporations Regulations 2001 (Cth), which specifies conduct that does not constitute the provision of a custodial or a depository service. Having regard to these provisions, the Authority is satisfied Western Power would not be providing a custodial or depository service to users for the purposes of the Corporations Act. For similar reasons, it is difficult to see how Western Power is subject to the Banking Act in circumstances where it is not carrying on a "banking business" as that term is defined in section 5 of the Banking Act.

2473. Western Power's third reason for not accepting the required amendment is that it would result in Western Power incurring additional costs greater than the interest paid. The Authority does not consider Western Power would need to make significant changes to current business procedures in order to calculate, apportion and report on interest or that it is likely that the administrative burden of operating a separate bank account for each cash security deposit would be onerous.

2474. For the reasons outlined above, the Authority does not consider the revised proposed revisions to the access arrangement have adequately taken account of Draft Decision Amendment 67.

Required Amendment 49

An amendment is required to the ETAC to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

APPLICATIONS AND QUEUING POLICY

Access Code Requirements

2475. Section 5.1(g) of the Access Code requires that an access arrangement include an application and queuing policy (**AQP**). Sections 5.7 to 5.11 of the Access Code set out the requirements for an applications and queuing policy.

> 5.7 An applications and queuing policy must:
>
> (a) to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants; and
>
> (b) be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate; and
>
> (c) set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline; and
>
> (d) oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:
>
> (i) information in respect of the availability of covered services on the covered network; and
>
> (ii) if there is any required work:
>
> A. operational and technical details of the required work; and
>
> B. commercial information regarding the likely cost of the required work;
>
> and
>
> (e) set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants' access applications are competing applications; and
>
> (f) to the extent that contestable consumers are connected at exit points on the covered network, contain provisions dealing with the transfer of capacity associated with a contestable consumer from the user currently supplying the contestable consumer ("outgoing user") to another user or an applicant ("incoming user") which, to the extent that it is applicable, are consistent with and facilitate the operation of any customer transfer code; and
>
> (g) establish arrangements to enable a user who is:

(i) a 'supplier of last resort' as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and

(ii) a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations; and

(h) facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the 'market rules' as defined in section 121(1) of the Act; and

(i) if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.

5.8 The paragraphs of section 5.7 do not limit each other.

5.9 Under section 5.7(e), the applications and queuing policy may:

(a) provide that if there are competing applications, then priority between the access applications is to be determined by reference to the time at which the access applications were lodged with the service provider, but if so the applications and queuing policy must:

(i) provide for departures from that principle where necessary to achieve the Code objective; and

(ii) contain provisions entitling an applicant, subject to compliance with any reasonable conditions, to:

A. current information regarding its position in the queue; and

B. information in reasonable detail regarding the aggregated capacity requirements sought in competing applications ahead of its access application in the queue; and

C. information in reasonable detail regarding the likely time at which the access application will be satisfied;

and

(b) oblige the service provider, if it is of the opinion that an access application relates to a particular project or development:

(i) which is the subject of an invitation to tender; and

(ii) in respect of which other access applications have been lodged with the service provider,

("project applications") to, treat the project applications, for the purposes of determining their priority, as if each of them had been lodged on the date that the service provider becomes aware that the invitation to tender was announced.

5.9A If:

(a) an access application (the "first application") seeks modifications to a contract for services; and

(b) the modifications, if implemented, would not materially impede the service provider's ability to provide a covered service sought in one or more other access applications (each an "other application") compared with what the position would be if the modifications were not implemented,

then the first application is not, by reason only of seeking the modifications, a competing application with the other applications.

5.10 An applications and queuing policy may:

(a) be based in whole or in part upon the model applications and queuing policy, in which case, to the extent that it is based on the model applications and queuing policy, any matter which in the model applications and queuing policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model applications and queuing policy; and

(ii) sections 5.7 to 5.9;

(iii) the Code objective; and

(b) be formulated without any reference to the model applications and queuing policy and is not required to reproduce, in whole or in part, the model applications and queuing policy.

5.11 The Authority:

(a) must determine that an applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective to the extent that it reproduces without material omission or variation the model applications and queuing policy; and

(b) otherwise must have regard to the model applications and queuing policy in determining whether the applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective.

Current Access Arrangement

2476. The current access arrangement includes, at Appendix 1, an AQP describing the process that an applicant (i.e. a person who seeks to obtain or modify a covered service) must undertake with Western Power to form, or to modify, an access contract.

2477. The current AQP deals with the following matters:

- procedural requirements for an access application and access offer (Part A);
- procedural requirements specific to an electricity transfer application (Part B); and
- procedural requirements for a connection application (Part C).

2478. The procedural requirements for a connection application include "queuing rules" (clause 24). The queuing rules apply where Western Power receives two or more competing connection applications: that is, applications for which the provision of the service sought in one connection application may impede Western Power's ability to provide the covered services that are sought in other connection applications.

2479. Under the current AQP, Western Power may:

- establish more than one queue, such as different queues for different parts of the network (clause 24.4);
- determine that an application will by-pass a queue (clauses 24.5 to 24.9);
- assign the same priority in a queue to applications that are competing under a tender process such that only one application will ultimately proceed with an access contract (clause 24.10);
- determine that an application is a "dormant application" and make a determination on whether the dormant application should be taken to have been withdrawn (clause 24.14).

Proposed Revisions

2480. Western Power provided the following reasons for requiring revisions to the AQP.[643]

> - "Western Power faces significant challenges in undertaking applicant studies in accordance with the current policy and this is leading to delays and costs that are ultimately worn by applicants.
> - The current policy requires Western Power to exercise discretion over an applicant's readiness to progress and this introduces risks of error by Western Power which may adversely affect the applicant (i.e. the risk of incorrectly determining an application as dormant or incorrectly determining that an application may by-pass the queue).
> - The current process distorts the basis on which new generation projects can compete in the wholesale electricity market, with potential adverse impacts on the wholesale electricity market and on the commissioning of renewable energy projects."

2481. Western Power's proposed revised AQP is contained in Appendix B of the proposed revisions to the access arrangement. Western Power describes the broad nature of revisions to the AQP as follows:[644]

- Customer driven nature

  "[A]pplicants determine how they progress through the process through explicit decision stages where they lodge applications, initiate planning studies, accept/decline preliminary offers and decide whether to accept the final access offers that [Western Power] make to them. Beyond these decisions the process is largely mechanical, which removes our need to exercise discretion by classifying customer applications as dormant or initiating bypass of applications to promote other applicants in the queue."

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643 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, p. 324.

644 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, pp. 325, 326.

- Less need for a queue

  "At present there is a single queue where applicants remain in the order they arrive, regardless of their readiness to proceed to connection. Instead ... the applicants that are commercially ready with viable projects determine their own willingness to proceed, or alternatively withdraw from the process as they approach decision stages and the payment of associated fees."

2482. Western Power describes key aspects of the revisions as follows:[645]

> "The addition of a formal enquiry stage – included to facilitate the exchange of information and to assist applicants to better indicate their requirements.
>
> The creation of 'competing applications groups' (CAGs), where applicants are grouped behind common network constraints to assess and tailor joint network solutions to provide access to all applicants within the CAG – rather than the current process which provides one-off, single applicant solutions that leads to the less efficient and more costly augmentation of our network over time.
>
> Limited use of queuing – different pathways exist for customers with different issues. There is no longer a single queue and applicants will only queue if a particular CAG is over-subscribed."

2483. Further elements of the proposed revisions are listed by Western Power as follows:[646]

- "The 'enquiry response letter' will provide the applicant with information on capacity, known network constraints and the existence of competing applications.
- Applicants can select their own engineering firm to undertake the necessary studies required by the applications and queuing policy process.
- Where study costs exceed [Western Power's] pre-estimate, applicants will be advised before additional costs are incurred and will have the opportunity to choose their desired course of action.
- Western Power will inform all applicants in a CAG when an applicant-specific solution has been prepared for one of the applicants within the CAG, to provide all applicants with an opportunity to object.
- Applicants will be advised in writing seven business days prior to a 'deemed withdrawal' as a result of their unpaid fees or charges.
- Applicants will be able to amend their application after the applicant has received a preliminary access offer, where [Western Power] agree that the amendment sought is not material.
- When processes are commenced to develop joint network solutions for a CAG, those processes will not be interrupted by new applications except in circumstances where existing applications have withdrawn and new applications can replace the existing applications without delay to the process.
- Timelines for various procedural steps have been inserted including:

645 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, p. 326.

646 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, p. 327.

- the time to process enquiries (40 business days)
- the time to resolve objections to applicant-specific solutions (40 business days)
- Indicative timeframes for provision of preliminary and final access offers to applicants in a CAG (30 business days)."

2484. Western Power considers that the proposed revisions to the AQP are likely to lead to a more economically efficient connection of projects for the following reasons:[647]

- "There is a more straightforward process for applications not subject to constraints.

  Applications that are not subject to constraints from the CAG process have a more direct pathway to connection. For example, 'transfer only' or 'connection only' applications can proceed immediately to connection without being held up by applicants that sit above them in the queue but that face delay due to network constraints. This creates a more efficient process for applicants that are not competing for limited capacity on the shared network.

- Work to augment the network to provide customer access occurs according to constraint/issue type rather than being driven by individual customers.

  [Western Power's] revisions allocate customers with similar constraints together into CAGs so that [Western Power] can focus on resolving the common network constraint, rather than single augmentations for each individual customer. This means work to successfully resolve the constraint means many customers can move forward and if any customer wishes not to proceed they can leave the group without disrupting the others.

  Under [Western Power's] current approach, customers are placed in a single queue and work to connect them occurs on an individual customer basis. This can result in inefficiencies as any changes to a customer's application (for example, a customer leaving the queue or not being ready to proceed) impacts those in the queue behind them. This requires costly and continual study reworks to re-evaluate the queue each time a project's status changes, or if a 'queue bypass' is required when an applicant is unduly holding up others in the queue.

- Long-term strategic network augmentations deliver more efficient network outcomes.

  Grouping applicants within CAGs also provides greater scope to deliver long-term strategic network augmentations. The use of CAGs provides visibility to identify the types of constraints and number of applicants impacted and, as a result, allows planning decisions to be made that will see the greatest number of customers efficiently connected at the same time. Network augmentation in this manner is likely to bring about more efficient, lower cost solutions in comparison to a process which makes continuous and numerous one-off augmentations to connect individual applicants."

2485. In its response to the Authority's Draft Decision, Western Power submitted an amended AQP as part of its revised proposed revisions to the access arrangement. Changes from the AQP submitted in September 2011 are discussed below under "Considerations of the Authority".

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647 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, pp. 326, 327.

Considerations of the Authority

2486. The Authority is required to assess the proposed revisions to the AQP against the requirements of sections 5.7 to 5.11 of the Access Code.

2487. During the first round of public consultation the Authority received 13 submissions which referred to Western Power's proposed revisions to the AQP. Except for submissions from Synergy and Pacific Hydro, submissions were broadly in support of the proposed revisions to the AQP.

2488. The concerns raised by Synergy primarily relate to its view that the proposed AQP provides Western Power with absolute discretion to constrain connection and covered services and that it would be more appropriate to deal with network constraints through economic initiatives and price signals. The Authority does not agree that the proposed AQP provides Western Power with absolute discretion to constrain connection and covered services. Further, whilst economic initiatives and price signals may form part of a better solution to network constraints, the Access Code requires Western Power to include an AQP in its access arrangement and the Authority is obliged to assess that policy against the requirements of the Access Code.

2489. The matters raised by Pacific Hydro relating to the operation of the policy are addressed by the Authority below.

2490. In assessing whether the proposed revised AQP meets the requirements of the Access Code, the Authority has considered the following:

- the interests of the service provider, users and applicants;
- sufficient detail on how the AQP will operate;
- timelines;
- information provision by Western Power;
- priority;
- Customer Transfer Code;
- suppliers of last resort and default suppliers;
- facilitation of Part 9 of the Act;
- priority of access applications lodged before the start of the third access arrangement period; and
- other matters raised in submissions.

Interests of the service provider, users and applicants

2491. Section 5.7(a) of the Access Code requires that an AQP must, to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants.

2492. On 23 December 2010 the Authority received a proposal from Western Power to vary its AQP. After a public consultation process and assessment of key issues raised, and noting the short period of time before the third access arrangement review was to commence, the Authority determined not to vary the AQP mid-term and referred it for assessment as part of the third access arrangement review process as there were a number of issues raised in submissions that it considered needed to be addressed.

2493. Western Power states that its proposed AQP for the third access arrangement build on the mid-term revisions that were proposed during the current access arrangement period and take into account the issues stakeholders raised through the Authority's consultation process. Western Power has provided a summary of how it has responded to those issues.[648]

2494. The Authority acknowledges the effort Western Power has made to take into account the interests of users and applicants. The Authority notes that there has been considerable work, review and discussion undertaken to date by many parties over a long period of time, as outlined below:

- July 2009 – The Authority's "2009 Annual WEM Report" raised concerns in relation to Western Power's existing AQP first-come first-served queuing rules and their interaction with the WEM and the reserve capacity mechanism, suggesting it did not serve to promote efficient investment in the electricity network.
- August 2009 – Western Power released a Discussion Paper on AQP issues with initial proposals seeking views from interested parties and held a public forum.
- September 2009 – an AEMC review of Western Australia's energy market framework commented on and suggested changes were required to Western Power's connections application process.
- December 2009 – Western Power published its Consultation Proposal, providing background and rationale for proposed AQP changes (follow-up submissions were received).
- November 2010 – Western Power held an AQP public forum on its proposed changes (40 attendees).
- December 2010 – Western Power submitted proposed mid-term AQP to the Authority (pursuant to Access Code 4.41).
- January 2011 – The Authority sought public submissions on Western Power's proposed mid-term AQP revisions (6 received).
- April 2011 – The Authority determined not to vary the AQP mid-term but referred it for assessment in the upcoming third access arrangement review process as there were a number of issues raised in submissions which needed to be addressed.
- September 2011 – Western Power submitted its proposed revisions to the access arrangement, including Western Power's response to the queries raised in the submissions received during the Authority's public submission process.

2495. In its submission the Office of Energy raised a concern that the detailed mechanics of the proposed AQP may not have been fully developed or may not have been adequately communicated to and understood by stakeholders. The Office of

648 Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, Appendix J: Response to submissions to the proposed mid-term revisions to the applications and queuing policy.

Energy therefore proposed that Western Power should provide a further series of workshops to interested stakeholders.

2496. In its submission Pacific Hydro notes the time that has passed since Western Power's original proposal in December 2009 and considers there is a need for specific consultation in relation to the AQP as it considers the scope of the access arrangement limits the ability for the dedication of specific time and resources on this topic.

2497. Western Power held a stakeholder workshop on 3 February 2012 to provide further explanation and opportunity for comment in relation to the proposed AQP. The forum was attended by a broad cross-section of interested parties. Many issues, queries, questions and criticisms were raised and discussed in what appeared to be a very beneficial workshop for all attendees.

2498. The Authority considers that Western Power has undertaken an adequate consultation process with interested parties. Submissions received by the Authority from interested parties who have direct practical experience of the current AQP, indicates significant support for the proposed revisions. Apart from a number of specific concerns, which the Authority has addressed below, having regard to the level of consultation and the submissions received by the Authority in support of the proposed revisions, the Authority is satisfied the proposed revisions comply with the requirements of section 5.7(a) of the Access Code.

2499. Only one submission made in the second round of public consultation commented on the AQP. Alinta's submission noted that it is generally supportive of the amendments required by the Authority to the AQP and believes that they are likely to lead to superior outcomes than achieved through the current policy.

2500. Alinta's submission also raised specific issues in relation to the process for determining whether a project is ready to proceed. This, and the specific concerns raised in submissions during the first round of public consultation have been addressed by the Authority below.

Formal Enquiry Process

2501. In its submission Perth Energy questioned whether the proposed formal enquiry process would materially reduce time and resources for an access application compared to an informal enquiry stage.

2502. Whilst the actions under a formal or informal enquiry may be similar, the Authority is of the view that a description of the full process of enquiry in the policy improves the process by clarifying actions and expectations.

Deemed Withdrawal of Applications

2503. In its submission Landfill Gas and Power considers the provisions for the deemed withdrawal of an application should be conditional on an express requirement in the policy for Western Power to act reasonably.

2504. The Authority agreed and accordingly, in the Draft Decision, required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 68

The applications and queuing policy must be amended to include an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn.

2505. In response to the Draft Decision, Western Power states that it has:

> "…revised the AQP to require Western Power and applicants to act reasonably and in good faith with each other in relation to an application generally. This general statement will capture all aspects of dealing with an application, including the process of determining when an application is deemed to have been withdrawn.
>
> Western Power will amend clause 3.1 of the AQP as follows:
>
> **Applications to be made in good faith**
>
> Western Power and an applicant must act reasonably and in good faith with regard to each other in relation to an application."[649]

2506. The Authority notes that if such an amendment is made, pursuant to clause 5.3 of the AQP, and if an applicant rejects an access offer and requests amendments, Western Power must negotiate in good faith regarding the application. However, if no access contract is signed within 30 business days of the rejection, then the application and any associated application will be deemed to be withdrawn. The effect of clause 5.3 is that the deemed withdrawal occurs automatically, following the failure to reach a negotiated agreement with Western Power.

2507. The Authority considers Western Power's proposed new wording in clause 3.1 will have the effect to require Western Power to act reasonably in the negotiations with the applicant contemplated under clause 5.3 and is sufficient to address the Authority's concerns in Draft Decision Amendment 68.

Technical Disputes

2508. In its submission ERM Power notes that technical disputes should be treated as an access dispute to be referred for arbitration under clause 20.4.

2509. Although clause 20.4 of the proposed AQP provides that a dispute on costs for a connection application may be referred to the arbitrator as an access dispute, it does not limit the matters that may be the subject of an access dispute. An access dispute is defined in section 1.3 of the Access Code and may include a dispute in relation to any of the terms, including technical requirements, for access. As such, the Authority does not consider it necessary for clause 20.4 to expressly state that technical disputes are to be referred to arbitration. However, to avoid doubt, the Authority considers clause 20.4 should be amended to include a statement to that effect.

2510. The Draft Decision required the following amendment to the proposed revisions to the access arrangement.

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649 Western Power, Amended access arrangement information for the Western Power Network, May 2012, p. 243.

Draft Decision Amendment 69

Clause 20.4 of the applications and queuing policy must be amended to include the following:

"Nothing in this clause limits the matters that may be the subject of an access dispute."

2511. In its response to the Draft Decision, Western Power accepts the required amendment and has made the necessary adjustment in its revised proposed revisions to the access arrangement.

2512. The Authority is satisfied that Western Power's amendments to clause 20.4 of the AQP adequately implements Draft Decision Amendment 69.

Fees for Enquiry Stage

2513. Section 18.4 of the proposed AQP provides for Western Power to charge a non-refundable fixed fee when an applicant lodges an enquiry.

2514. Wind Prospect's submission considers the formal enquiry stage should be a free service and notes this to be the case under the NEM. Wind Prospect considers that if a fee is to be charged, it should not be non-refundable and the level of fee should be explicitly stated within the AQP.

2515. The Authority considers it is reasonable for Western Power to charge a non-refundable fee, having regard to the administrative costs associated with the enquiry stage and in aiming to discourage spurious applications. Under clause 17A.1 a party is able to have informal non binding discussions with Western Power, which the Authority considers should give a prospective applicant an opportunity to evaluate whether it wishes to proceed to lodge a formal application.

2516. In the Draft Decision, the Authority noted that the proposed Price List for 2012/13, which was included as Appendix F.1 to the proposed revisions to the access arrangement, includes a list of lodgement fees applicable to the AQP. The Authority considers it would be clearer to applicants if the AQP specifically referred to the Price List where relevant.

2517. In the Draft Decision, the Authority accordingly required the following amendment to the proposed revisions to the access arrangement.

Draft Decision Amendment 70

The applications and queuing policy must include specific reference to the Price List in relation to the relevant fees.

2518. In response to the Draft Decision, Western Power has accepted this amendment and has proposed the following amendments to the AQP:[650]

650 Western Power, Amended access arrangement information for the Western Power Network, May 2012, p. 245.

Clause 18.4 of the AQP will be amended to include:

At the time that the applicant lodges an enquiry under this clause 18, Western Power may charge a non-refundable fixed fee for processing the enquiry as specified in the price list…

Clause 24.3(a) of the AQP will be amended to include:

… paying the preliminary offer processing fee as specified in the price list…

Clause 24.5(b) of the AQP will be amended to include:

… a preliminary acceptance fee as specified in the price list…

2519. Western Power notes there are fees that are levied on applicants that are not firm value fees in the price list, including some applicant specific costs. For avoidance of doubt, Western Power notes it has included a note in the price list definition, in clause 2.1, to inform applicants that some applicant specific costs that may be levied may not be specified as firm value fees in the price list.

2520. Western Power proposes to amend the clause 2.1 price list definition as follows;

"price list" means the price list (as defined in the Code) in the access arrangement.

{Note: Some costs and fees that may be levied under this applications and queuing policy may not be specified as firm values in the price list.}

2521. The Authority considers the amendments proposed by Western Power adequately address the requirements of Draft Decision Amendment 70.

Removal of Bypass Provisions

2522. In its submission, Pacific Hydro raises concerns in relation to the removal of the bypass provisions in the proposed revised AQP. Pacific Hydro considers the existing bypass arrangements to be adequate for generation and that Western Power has not provided details on why the current bypass process is not efficient.

2523. The Authority notes that Western Power considers the implementation of the bypass mechanism has proven to be problematic in practice and, even when implemented effectively, it does not make provision for joint connection solutions. Western Power considers that retaining applicant-specific solutions as an option produces the same result as an efficiently implemented bypass mechanism.[651]

2524. The Authority considers Western Power's approach to be reasonable, having regard to the difficulties associated with the existing AQP.

Applicant Specific Solutions

2525. Perth Energy's submission considers Western Power's proposal, i.e. that members of a competing applications group can object if one member of the group is offered an applicant-specific solution, may be used in a vexatious manner to hinder the

[651] Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, Appendix J: Response to submissions to the proposed mid-term revisions to the applications and queuing policy, p. 17.

progress of a competing application or to enforce participation in a joint solution that may not be in the best interest of individual applicants. Perth Energy considers the process for competing applications groups needs to allow for individual applicants to opt out of a competing applications group and to pursue stand-alone access applications where the participation in a competing applications group may hinder the progress of an access application.

2526. The Authority notes that, pursuant to clause 20.3(a) of the proposed AQP, an applicant may request Western Power to perform a study of the nature and costs of an applicant-specific solution to satisfy the connection application.

2527. However, pursuant to clause 20.3(b) of the proposed AQP, once Western Power has completed the study, it must provide existing users and any competing applicants within the same competing applications group as the applicant, with the opportunity to object to providing the applicant-specific solution to the applicant. Under clause 20.3(c) of the proposed AQP, existing users and competing applicants may object on the grounds that:

- the applicant-specific solution would impede Western Power's ability to provide covered services to the existing user; or
- the applicant-specific solution would impede Western Power's ability to provide the covered services that are sought in a competing application compared with what the position would be if the applicant-specific solution were not implemented.

2528. Clause 20.3(d) of the AQP requires Western Power to evaluate any such objections within 40 business days of such an objection being lodged. If Western Power agrees that the applicant-specific solution would impede its ability to provide covered services to an existing user or to provide the covered services that are sought in the other connection application to a competing applicant, then it must either decline to offer an applicant-specific solution to the applicant or modify the applicant-specific solution to remove the impediment.

2529. The Authority notes that clause 24.2 gives Western Power the discretion to determine that an application be treated as part of a competing applications group. However, under clause 24.3, an applicant may withdraw its application if it does not agree to have its application considered within a competing applications group. Further, under clause 24.5(ii), an application will be deemed to be withdrawn if the applicant and Western Power are unable to agree on the terms of a preliminary access offer within the timeframe specified in that clause.

2530. Sections 2.10 and 2.11 of the Access Code require Western Power to undertake required works to provide a connection subject to the user paying any necessary contribution to the costs of those required works. In its Draft Decision the Authority considered that the proposed AQP was not consistent with the applicant's rights under sections 2.10 and 2.11 of the Access Code as it did not provide for an applicant to have an application treated independently of any other application, even in circumstances where the applicant will fully fund the solution.

2531. In the Draft Decision the Authority therefore required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 71

To ensure the applications and queuing policy is consistent with sections 2.10 and 2.11 of the Access Code, the applications and queuing policy must provide for an applicant to have an application treated independently of any other application. To give effect to this requirement:

- clauses 24.2 and 24.3 must be amended to provide for an applicant to opt out of the competing applications group process before that process commences and for the application to be treated as an application for an applicant-specific solution; and
- clause 24.5 be amended so that if an applicant does not reach agreement with Western Power on a preliminary access offer as part of the competing applications group process, the application is not deemed to be withdrawn but is to be treated as an application for an applicant-specific solution.

2532. In response to the Draft Decision, Western Power accepted the required amendment and proposed the following changes:[652]

Clause 24.2 is amended as follows:

> Where Western Power considers that a single set of works for shared assets may meet some or all of the requirements of the applicants within a competing applications group, it will issue a notice of intention to prepare a preliminary access offer to all applicants within that competing applications group, and charge a preliminary offer processing fee <u>(provided that such preliminary offer processing fee is not payable by an applicant who under clause 24.3(b) elects to opt out of the competing applications group or who under clause 24.3(c) withdraws their application).</u>

Clause 24.3 is amended to include a new 24.3(b) as follows:

> <u>advising that they wish to opt out of the competing applications group, in which case they will be treated as having made an application for an applicant-specific solution and the applicant's connection application will be processed as an applicant-specific solution in accordance with clauses 19 and 20 (and the other relevant provisions) of this applications and queuing policy; or</u>

Clause 24.5(a)(ii) is amended as follows;

> …but if Western Power and the applicant have not agreed on the form of the preliminary access offer within 30 business days, then the <u>applicant will, unless it notifies Western Power that it wishes its connection application and any associated electricity transfer application, to be taken to be withdrawn, be treated as having made an application for an applicant-specific solution and the applicant's connection application will be processed as an applicant-specific solution in accordance with clauses 19 and 20 (and the other relevant provisions) of this applications and queuing policy;</u>

2533. Western Power notes that the "opted out" application will follow the standard applicant-specific process and will not avoid the objections component of that process (set out under clause 20.3).

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[652] Western Power, Amended access arrangement information for the Western Power Network, May 2012, pp. 246-247.

2534. Western Power considers the changes to clauses 24.3 and 24.5 (plus the changes through Amendment 76) also require a modification to clause 24.7 to recognise that the composition of a competing applications group may change when an applicant is to be treated as having made an application for an applicant-specific solution. Western Power has therefore amended clause 24.7 by adding the following words:

> or applicants whose applications are to be treated, under a clause of this applications and queuing policy, as having been made for an applicant-specific solution (for example under clause 24.3(b), 24.5(a)(ii) or clause 24.1(c)).

2535. Western Power also notes a small correction to clause 20.3(b)(ii) – the "is" in that clause should be a "was" (any *competing applicant* that ~~is~~ was within the same *competing applications group* as the *applicant*) because once an applicant has been moved into an applicant-specific solution option they are no longer part of a *competing applications group*.

2536. The Authority notes that the amendments proposed by Western Power only enable an applicant who is willing to fund its own solution with an option to "opt out" of the competing applications group after Western Power issues a notice under clause 24.2. The Authority does not consider Western Power's proposed amendments fully comply with the requirements of Draft Decision Amendment 71. The Authority requires Western Power to amend the AQP such that applicants are able to elect at the time of application, that they wish to be processed as an applicant-specific solution so that the AQP is consistent with an applicant's rights under 2.10 and 2.11 of the Access Code.

Required Amendment 50

The AQP must be amended to enable applicants to elect, at the time of application, that they wish the application to be processed as an applicant-specific solution.

Progress of Applications

2537. In its submission during the first round of public consultation, Alinta considered applicants should be required to meet specific criteria, such as environmental approval, fuel supply agreements or power purchase agreements, before being able to progress from the enquiry stage to the connection application stage.

2538. In the Draft Decision the Authority noted Alinta's concern that parties may submit applications prior to projects being sufficiently developed for the application to proceed in a timely manner, thereby possibly delaying the processing of applications of other parties. However, the Authority considers that to accommodate applicants' needs, in some cases these processes will need to progress in parallel. The Authority considers that the provisions contained in the proposed AQP requiring applicants to submit an application form that includes all of the relevant information set out under clause 3 provides a reasonable balance of accommodating specific applicant's needs with ensuring other applicants are not unnecessarily disadvantaged.

2539. Alinta's submission during the second round of public consultation is generally supportive of the amendments required by the Authority but includes the following:

> Alinta does however note that the Authority has declined to require Western Power to include more prescriptive criteria to determine whether a project is ready to proceed, concluding that the access application form should be sufficient for it to make such an assessment. This approach would appear to risk a continuation of the potential problem that projects that are conceptual, rather than ready to commence construction, may be prioritised into the same applications queue. At the least, this would appear to create a further administrative burden on Western Power, with the possibility that projects ready to proceed sit grouped with projects that are only in an early planning stage. Grouping a ready to proceed project with other projects that are only in the planning stages is likely to result in those less advanced groups exiting from a "competing applications" group. This would require the ready to proceed projects to start again and negotiate an individual solution with Western Power. In the second case, Alinta believes that this is one of the major problems with the current operation of the AQP and we are eager to see the detail behind the new AQP to ensure this issue is appropriately dealt with.[653]

2540. The Authority notes Alinta's concerns but maintains its position as set out in the Draft Decision. The Authority considers the proposed applications and queuing policy, which requires that applicants provide a complete application form, including all of the relevant information set out in clause 3, provides a reasonable balance of accommodating specific applicant's needs with ensuring other applicants are not unnecessarily disadvantaged. The Authority also notes that Draft Decision Amendment 71 required Western Power to enable applicants to opt out of the CAG process. This would give applicants the option to not be included in a CAG group that the applicant considered included applicants who are not sufficiently progressed.

2541. However, as noted by Alinta, the AQP needs to include sufficient detail on how the applications and queuing policy will operate, including how the competing applications group process will work. This is considered further in the next section.

Sufficient detail on how the applications and queuing policy will operate

2542. Section 5.7(b) of the Access Code requires that an applications and queuing policy must be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate.

2543. In some submissions[654] received by the Authority, parties have expressed concern over a lack of detail setting out the operation of the 'competing applications group' mechanism.

2544. Having regard to the submissions received, the Authority considers the mechanisms and processes with respect to the competing applications group could be more clearly defined, whilst ensuring that those mechanisms do not become unworkable. The Authority acknowledges that there needs to be a balance between adhering strictly to a prescriptive process and allowing Western Power the flexibility to be able to identify and implement an efficient network investment that meets the needs, collectively, of applicants.

2545. In the Draft Decision the Authority accordingly required the following amendment to the proposed revisions to the access arrangement.

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653 Alinta

654 Griffin Power, Alinta.

Draft Decision Amendment 72

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a "competing applications group" will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

2546. In response to the Draft Decision, Western Power has accepted Draft Decision Amendment 72 and agrees there needs to be more clearly defined provisions. However, Western Power states it has found it difficult to respond to stakeholder requests for further information because stakeholders have not been able to articulate the specific issues on which they want more detail and the nature of the detail they want. Western Power has suggested that a more appropriate way of meeting the requirement for more information would be by including a requirement in the AQP for Western Power to publish an AQP document:

> "The AQP guideline will detail how the policy will operate in practice, including the steps that will be followed when applications are placed in a CAG. The guideline can be written in a more practical manner than compared to the legal style of the AQP, allowing it to provide a more hands on guide to stakeholders."

2547. The Authority has a number of concerns with Western Power's response to Draft Decision Amendment 72.

2548. Firstly, the Authority considers a guideline contained in a separate document to the AQP will not comply with the requirements under the Access Code that an access arrangement must contain an AQP (section 5.1(g)), which is defined as "a policy in an access arrangement setting out the access application process (section 1.3)" and must be sufficiently detailed to enable users and applicants to understand in advance how the AQP will operate".

2549. Further, the Authority does not accept Western Power's submission that it does not sufficiently understand the details of the additional information required by stakeholders in relation to how the competing applications group will operate. Draft Decision Amendment 72 sets out clearly the specific issues that need to be addressed in relation to the competing applications process. The issues mentioned in Draft Decision Amendment 72 are fundamental to the operation of the AQP and are not minor matters of procedure, more suited to a guideline.

2550. The Authority notes that Western Power recognises that it should be providing additional information to prospective users but proposes to do so in a document separate to the access arrangement. The Authority is concerned that not including the document within the access arrangement results in it falling outside the access arrangement approval process and transfers aspects of the AQP from the Authority's jurisdiction under the Access Code to Western Power's general discretion. Although Western Power has included a detailed public consultation process for development of the guideline, involving all interested parties, it is not clear that Western Power is ultimately obliged to comply with a direction from the

Authority with respect to the content of the guideline. Similarly, Western Power appears to retain ultimate discretion in relation to a proposed amendment to the AQP. Consequently, whilst the Authority agrees that the additional information requirements would be best included as a stand-alone document, that document must be included as an appendix to the access arrangement.

2551. For the reasons set out above, the Authority does not consider Western Power's proposal meets the requirements of Draft Decision Amendment 72. The Authority therefore maintains its requirement for Western Power to amend the revised proposed revisions to reflect Draft Decision Amendment 72.

Required Amendment 51

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a "competing applications group" will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

Timelines

2552. Section 5.7(c) of the Access Code requires that an AQP must set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline.

2553. The Authority has received submissions raising concerns with respect to the timelines under the AQP. The Authority considers these issues below.

Penalties for Non Compliance

2554. Perth Energy supports the timelines specified in the proposed AQP, but considers Western Power should face penalties if it does not comply with the relevant prescribed timelines.

2555. The Authority observes that any non-compliance with the AQP (including timing requirements) is dealt with under the access disputes regime under Chapter 10 of the Access Code, (in particular, section 10.29(a)). Accordingly, the Authority does not consider any amendments are required to the AQP in this respect.

Time Limits for Applicant Specific Solutions

2556. In its submission, ERM Power considers that time limits should be included in section 20.3 dealing with applicant-specific solutions.

2557. As discussed in paragraphs 2525 to 2530 above, the Authority considers the AQP should allow an applicant to opt out of the competing applications group process, in which case full timelines for the applications process should apply to an applicant-specific solution.

2558. The Authority accordingly required the following amendment to the proposed revised access arrangement.

> **Draft Decision Amendment 73**
>
> Timelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

2559. In response to the Draft Decision, Western Power has proposed alternative amendments that it considers addresses the required amendment. In the amended access arrangement information, Western Power notes:

> The initial stages of the AQP processes are common for CAG and applicant-specific solution applications. In later stages the CAG process becomes multilateral but the applicant-specific solution process remains bilateral and so different milestones and timelines apply.
>
> Western Power considers the Authority's required amendment is best achieved by including specific process milestones in the AQP. The AQP should also note that achieving the timelines depends on the applicant's cooperation with Western Power.
>
> Western Power accepts that the AQP will be revised in clause 20.3 to include timelines for the applicant-specific solution process. They do not necessarily match the timelines for competing applications groups reflecting the different nature of each process. It has also revised the wording of the clause to provide that when Western Power is preparing the study, achieving the timeline is dependent on the applicant's cooperation.
>
> The amendments are summarised below.
>
> - 60 business days for the study and timeline is dependent on the applicant's cooperation when preparing the study. Clause 20.3(a) will be amended to include:
>
>   > <u>Western Power will endeavour, subject to receiving any necessary cooperation from the applicant, to complete the study within 60 business days.</u>
>
> - 30 business days for objections. Clause 20.3(c) will be amended to include
>
>   > An existing user and competing applicant may object to the applicant-specific solution <u>within 30 business days</u> …, and
>
> - 30 business days for Western Power to make an offer. Clause 20.4(e) will be amended to include:
>
>   > …then Western Power <u>within 30 business days</u> must make an access offer …

2560. Given the different nature of the processes for competing application groups and applicant-specific solutions, the Authority agrees it is appropriate to include specific process milestones in the AQP. The Authority has considered Western Power's proposed timelines in the following paragraphs.

2561. Under clause 19.1(a), Western Power must provide an initial response to an applicant within 20 business days of receiving the applicant's connection application, specifying the time by which Western Power will provide a preliminary assessment and the time by which Western Power expects to make an access offer.

2562. The Authority notes that clause 24 of the AQP establishes the following process and timelines for the competing application group.

- Where Western Power considers that a single set of works for shared assets may meet some or all of the requirements of the applicants within a competing applications group it will issue a notice of intention to prepare a preliminary access offer to all applicants within the competing application group (clause 24.2).
- Applicants must respond to the notice within 30 business days, indicating whether they accept the preliminary access offer, wish to opt out of the competing application group (and have their application addressed under the applicant-specific process), or withdraw their application (clause 24.3).
- Following the response of applicants under clause 24.3, Western Power, if it continues to consider that a single set of works for shared assets may meet some or all of the requirements of the competing applications group, will endeavour to make a preliminary access officer to each applicant within the relevant competing application group within 60 days of issuing the notice (clause 24.4).
- Applicants must respond within 30 business days of receipt of the preliminary access offer, indicating whether they would accept the preliminary access offer, require amendments to the preliminary access offer, or reject the preliminary access offer (clause 24.5). Unless the applicant notifies Western Power that it wishes its application to be taken to be withdrawn, applicants who reject the preliminary access offer are treated as having made an application for an applicant-specific solution and the application will be processed in accordance with clauses 19 and 20.
- Western Power will endeavour, within 30 business days of receipt of responses by all applicants to preliminary access offers under clause 24.5, to make an offer (including prioritised offers) or revise its preliminary access offer (clause 24.6).
- Under clause 5.2, once an applicant receives an access offer it must respond within 30 days.

2563. The Authority notes that clause 20.3 of the AQP, incorporating Western Power's revised proposed revisions, establishes the following process and timelines for applicant-specific solutions.

- If an applicant requests a study of the nature and costs of an applicant-specific solution to satisfy the connection application, Western Power will endeavour, subject to receiving any necessary cooperation from the applicant, to complete the study within 60 business days (clause 20.3(a)).

- Once the study is complete, Western Power must provide existing users, and any competing applicants in the same competing applications group as the applicant, with the opportunity to object to the applicant-specific solution within 30 business days. Grounds for objection are that the applicant-specific solution would impede Western Power's ability to provide covered services to existing users or to provide covered services that are sought in a competing application compared with what the position would be if the applicant-specific solution were not implemented (clause 20.3(b) and (c)).
- Western Power must evaluate any objection within 40 business days of it being lodged. If it agrees the objection is valid, then it must either decline the applicant-specific solution or modify it. If Western Power elects to modify the solution, then it must provide a further opportunity to object under clause 20.3(c).
- If no objections are made, or if Western Power evaluates under clause 20.3(d) that the applicant-specific solution does not impede Western Power's ability to provide covered services, then Western Power must make an access offer to the applicant based on the applicant-specific solution within 30 business days.

2564. The Authority notes that the lapsed time between an applicant requesting a study and Western Power making an access offer (assuming there are no objections under clause 20.3(c)) is 120 days. This would extend to at least 160 days if an unsuccessful objection was made and longer if a modified solution is adopted requiring additional time periods for objections to be raised.

2565. In the case of competing applications groups, the lapsed time between Western Power issuing a notice of intention to prepare a preliminary access offer to all applicants within a competing applications group and the date by which all applicants must accept or reject an access offer (assuming there is no reworking of the solution due to applicants dropping out along the way) is 150 days.

2566. The timelines proposed by Western Power in relation to applicant-specific solutions appear reasonable in themselves. However, the Authority is concerned about how these timelines would relate to the competing applications group process. As discussed in paragraphs 2542 to 2551 above, Draft Decision Amendment 72 required the mechanisms and processes relating to Western Power's competing applications group to be more clearly defined. Western Power's revised proposed revisions have not addressed this requirement adequately. Until the requirements of Draft Decision Amendment 72 are dealt with adequately, it is not possible to conclude whether the timescales in relation to applicant-specific solutions are appropriate.

2567. Consequently, the Authority retains the requirements of Draft Decision Amendment 73.

Required Amendment 52

Timelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

Enforcement of Timelines

2568. Moonies Hill submitted that clauses within the AQP relating to timelines should be worded to force Western Power to adhere to a firm obligation (e.g. section 18.2(a)(b) – the requirement that Western Power must "endeavour" to perform work within a reasonable time" should be change to "must perform work within a reasonable time").

2569. The Authority considers it reasonable that such a requirement should be placed on Western Power if the activity to which the timeline relates is one that is predictable and to which a pre-determined timeline can reasonably be established. However, for activities that are difficult to predict, the Authority considers it reasonable that it be on a "best endeavours" basis. In the Draft Decision, the Authority suggested Western Power review the proposed AQP to ensure the timeline requirements are appropriate and welcomed further views from interested parties.

2570. No submissions received during the second round of public consultation made any further comment in relation to this matter. The Authority notes that the specific timeline mentioned by Moonies Hill (i.e. section 18.2(a)(b)) is dealt with in Draft Decision Amendment 74 below.

Timeframe for Responding to Enquiries

2571. Wind Prospect considers Western Power should be required to respond to enquiries within 20 business days rather than the 40 business days proposed by Western Power.

2572. In the Draft Decision the Authority noted that Western Power had proposed the response letter will set out:

- a description of the information required for a complete application, and the results of any assessment that it may have carried out to indicate the extent of any spare capacity available to provide covered services;
- the existence of any competing applications; and
- any constraints known to Western Power on the ability of the network to provide the capacity proposed as contracted capacity in the connection application by the applicant.

This should be considered in the context of the potential actions required by Western Power in responding to the enquiry and whether 20 or 40 business days would be a better estimate of the time required for this activity.

2573. The Authority considered that most of this information should already be available to Western Power as part of its network planning and on that basis it would be reasonable to expect a response to be prepared within 20 business days. The Authority considered this would facilitate a more efficient process as an applicant would be able to more quickly determine whether it wished to proceed with an application. The Authority acknowledged there may be some cases with greater complexity that require a longer time frame and, in such cases, Western Power should be required to provide an expected response time to the applicant within 20 business days of lodgement of the enquiry.

2574. In the Draft Decision the Authority accordingly required the following amendment to the proposed revisions to the access arrangement.

Draft Decision Amendment 74

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

2575. In response to the Draft Decision Western Power states that it accepts that it is reasonable to expect Western Power to respond to an applicant's letter within 20 business days and that, in practice, this is likely to be achieved. However, Western Power considers it may not be possible to do so in all circumstances, and therefore does not accept the required amendment that Western Power **must** provide a response within 20 business days. Western Power proposes that it would be appropriate to amend the access arrangement revisions to include an obligation for Western Power to **endeavour** to provide a response within 20 business days.

2576. In the revised proposed revisions to the access arrangement, Western Power has amended clause 18.2A(b) as follows:

> Western Power will endeavour to send the enquiry response letter to the applicant within 20 business days of the lodgement of the enquiry, or within 20 business days of completion of any system studies or other works requested by the applicant under clause 18.2. <u>If Western Power is not able to provide all the information to be contained in the enquiry response letter to the applicant within 20 business days then it will within that 20 business days, send an enquiry response letter to the applicant with as much information as is available to Western Power, together with an estimated time within which the balance of the information will be provided. Western Power will endeavour to send the balance of the information to the applicant within a further 20 business days.</u>

2577. The Authority does not consider Western Power's proposed amendment adequately addresses the requirements of Draft Decision Amendment 74. The Authority acknowledges it will not always be possible to obtain all the required information within 20 business days but considers it reasonable to require Western Power to provide a response within 20 business days with as much information as possible and an estimated time of when the balance of outstanding information will be provided, being not greater than 20 business days. The Authority therefore retains the requirements of Draft Decision Amendment 74 to be implemented.

Required Amendment 53

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

Information provision by Western Power

2578. Section 5.7(d) of the Access Code requires that an AQP must oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in, effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:

- information in respect of the availability of covered services on the covered network; and
- if there is any required work:
  - operational and technical details of the required work; and
  - commercial information regarding the likely cost of the required work (5.7(d)).

2579. Some submissions received by the Authority raised concerns with respect to the level of information provided and that the confidentiality requirements of Western Power creates difficulties for applicants using external consultants. The Authority considers these matters below.

Level of Information Provided

2580. Submissions from Perth Energy and Moonies Hill consider that Western Power should be required to provide high level detail regarding:

- network access and capacity constraints and considerations;
- existing applications; and
- network performance issues that would be relevant to the deliberations of any prospective applicants.

2581. The Authority notes that clause 17A.1, which relates to pre-enquiry discussions, only states that Western Power will provide “reasonable” assistance and does not provide any detail of what that assistance might include.

2582. Under clause 18.1, the enquiry stage is only open to applicants who expect, in good faith, to proceed to a connection application. Clause 18.2A requires Western Power to issue an enquiry response letter to an applicant at the conclusion of the enquiry stage setting out:

- a description of the information required for a complete application, and the results of any assessment that it may have carried out to indicate the extent of any spare capacity available to provide covered services;
- the existence of any competing applications; and
- any constraints known to Western Power on the ability of the network to provide the capacity proposed as contracted capacity in the connection application by the applicant.

2583. The Authority notes that section 5.7(d) of the Access Code requires a service provider to provide certain information to enable an applicant to apply for an access contract. Under the proposed revisions to the AQP, Western Power is obliged to only provide such information to parties who expect, in good faith, to proceed to a connection application. The Authority notes the concerns raised by interested parties that prospective applicants should have access to such information. The Authority agrees that such information is needed to enable potential applicants to decide if they wish to pursue an application.

2584. In the Draft Decision, the Authority accordingly required the following amendment to the proposed revisions to the access arrangement.

Draft Decision Amendment 75

The applications and queuing policy must be amended to include an obligation for Western Power to provide potential applicants with all commercial and technical information reasonably requested, and subject to any reasonable confidentiality requirements, at the pre-enquiry stage.

2585. In response to the Draft Decision Western Power has inserted a new clause 17A.3 in the AQP, which it considers addresses the required amendment. The proposed new clause states:

> On request by the party, Western Power will, except to the extent that it is prevented from doing so by clause 6.2, provide the party with all existing commercial and technical information that is in Western Power's possession that is reasonably needed by the party to help it decide whether to make an *application*.

2586. The Authority notes that clause 6.2 of the AQP is a general prohibition on disclosure of confidential information in the following terms:

> Western Power, an applicant or a disclosing person must not disclose confidential information unless:
>
> (a) The disclosure is made to the Authority on a confidential basis;
>
> (b) The disclosure, where it is made by an applicant or a disclosing person, is made to a worker of Western Power who is bound by an adequate confidentiality undertaking; or
>
> (c) The disclosure is made with the consent of the disclosing person; or
>
> (d) The disclosure is required or allowed by law, or by the Arbitrator or another court of tribunal constituted by law; or
>
> (e) The information has entered the public domain other than by breach of this clause 6.2; or

(f) The information could be inferred by a reasonable and prudent person from information already in the public domain.

2587. Clause 2.1 of the AQP defines "confidential information" to mean:

(a) In the case of information disclosed by an applicant or a disclosing person to Western Power in or in connection with an application, information which the disclosing person (acting as a reasonable and prudent person) has identified as being commercially sensitive or confidential; and

(b) In the case of information disclosed by Western Power to an applicant or a disclosing person in connection with an application, information which Western Power (acting as a reasonable and prudent person) has identified as being commercially sensitive or confidential.

2588. A "disclosing person" is defined in clause 2.1 of the AQP to mean, in relation to an application, a person who discloses confidential information to Western Power in, or in connection with, an application.

2589. The Authority notes that Western Power's proposed new clause 17A.3 of the AQP is confined to information only in Western Power's possession. The Authority considers the proposed wording is too restrictive and should be expanded to also include information within Western Power's "custody or control".

2590. The Authority also considers that, to ensure that clause 6.2 of the AQP does not inappropriately restrict the level of information that can be provided, the following changes are required:

- an obligation be included for Western Power to use reasonable endeavours to enter into an adequate confidentiality undertaking with respect to information that has not been provided by a third party;
- a positive obligation to be imposed on Western Power to seek the consent of a disclosing party to disclosure of the confidential information; and
- if the disclosing party will not consent, then an obligation be included for Western Power to use reasonable endeavours to provide the information in an aggregated or other form in which its confidential aspects cannot be identified.

2591. The Authority requires the following amendments to the AQP:

17A.3 On request by the party, Western Power will, ~~except to the extent that it is prevented from doing so by clause 6.2~~ <u>subject to clauses 17A.4</u> and 6.2, provide the party with all existing commercial and technical information that is in Western Power's possession<u>, custody or control</u> that is reasonably ~~needed~~ <u>required or requested</u> by the party to help it decide whether to make an *application*.

17A.4 <u>Where commercial or technical information referred to in clause 17A.3 is *confidential information*:</u>

(a) <u>which has not been disclosed to Western Power by a third party, Western Power will use reasonable endeavours to enter into an adequate confidentiality undertaking with respect to the disclosure of the confidential information to the party deciding whether to make an application;</u>

(b) disclosed to Western Power by a *disclosing party* or an *applicant*, Western Power will use reasonable endeavours to obtain the consent of the relevant *disclosing party* or *applicant* to the disclosure of the *confidential information* to the applicant and, in the event that the relevant *disclosing party* or *applicant* does not consent to such disclosure, Western Power will use reasonable endeavours to provide the relevant *confidential information* to the party who has requested the information in an aggregated or other form in which its confidential aspects cannot be identified.

Required Amendment 54

Sections 17A.3 and 17A.4 of the AQP must be amended as set out in paragraph 2591 above.

Confidentiality Requirements for Consultants

2592. Pacific Hydro considers that the confidentiality requirements of Western Power make the use of external consultants difficult.

2593. The Authority notes Western Power has included provisions in the proposed revised AQP for the use of external consultants and will provide “all reasonable information” for such a purpose (clause 20.5). The Authority considers this requirement addresses the concerns raised by Pacific Hydro Australia. The Authority considers that the confidentiality requirements (i.e. that the consulting engineering firm enter into a confidentiality agreement with Western Power) are reasonable as the information provided may include information that is specific to particular network users and is commercially sensitive. The Authority notes there is nothing in clause 20.5 that indicates that information provision would be restricted for reasons of confidentiality.

Priority

2594. Section 5.7(e) of the Access Code requires that an AQP must set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants’ access applications are competing applications.

2595. The current AQP sets out rules in relation to queuing in clause 24. In the proposed revised AQP, clause 24 has been amended to set out the procedures dealing with competing applications and a new clause 24A has been included dealing with priority dates of applications competing under a tender process.

2596. No submissions made to the Authority raised concerns in relation to the procedure for determining priority of competing applications. The Authority has reviewed the proposed clauses and, having regard to the fact that no concerns have been raised in submissions, considers the proposed revised AQP adequately sets out the procedure for determining priority of applications.

Suppliers of last resort and default suppliers

2597. Section 5.7(g) of the Access Code requires that an AQP must establish arrangements to enable a user who is:

> (i) a 'supplier of last resort' as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and
>
> (ii) a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations (5.7(g)).

2598. Under the current AQP, provision is made for an application to bypass the queue when necessary to meet the requirements of section 5.7(g) of the Access Code (clause 24.5 of the current AQP). No equivalent provision is contained in the proposed revisions to the AQP and there is no specific reference in the proposed AQP to the circumstances set out in section 5.7(g) of the Access Code.

2599. A supplier of last resort is a retailer of electricity that assumes an obligation to make a retail supply of energy to a customer where the incumbent retailer of energy to that customer ceases to have a retail licence. A default supplier is a retailer of electricity that is deemed to have a supply contract with a customer that is taking energy at a connection point but does not have a contract with a retailer.

2600. The Authority notes that a supplier of last resort or a default supplier would only assume an obligation to supply energy where there is an existing connection point and existing supply of energy. Clause 9.1 deals with customer transfer requests. However, clause 9.1 was not specifically drafted to deal with a supplier of last resort assuming its obligations, and contains provisions that the Authority considers would constrain the ability of a supplier of last resort or a default supplier to meet their obligations.

2601. In its Draft Decision the Authority considered the proposed AQP did not make sufficient provision for a party to enter into an ETAC to meet obligations as referred to in section 5.7(g) of the Access Code.

2602. The Authority accordingly required the following amendment to the proposed revised access arrangement.

> **Draft Decision Amendment 76**
>
> The applications and queuing policy must be amended to include arrangements to enable:
>
> - A "supplier of last resort" as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and
> - a "default supplier" under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations (5.7(g)).

2603. Western Power has addressed Draft Decision Amendment 76 in a new clause 24.1(c), which states that:

> to the extent necessary to allow:

(i) A supplier of last resort (as defined in section 67 of the Act) to comply with its obligations under Part 5 of the Act; or

(ii) A default supplier (as defined in section 59 of the Act) to comply with its obligations under section 59 of the Act,

An applicant may advise Western Power at any time that it does not wish to be considered to be included within the competing application group, in which case it will be treated as having made an application for an applicant-specific solution in accordance with clauses 19 and 20 (and any other relevant provisions) of this applications and queuing policy."

2604. The Authority notes that the definition of applicant-specific solution includes a method of satisfying a connection application by "an *operational solution* involving only that applicant". An *operational solution* is defined as one that satisfies a connection application "that does not rely primarily on construction of new network assets or augmentation of existing network assets". This would encompass the role of becoming a supplier of last resort, which involves replacing an existing licensee.

2605. In its amended access arrangement information, Western Power states that clause 9.1 of its amended AQP deals with customer transfer requests made by retailers and is in identical terms to the existing AQP. Clause 9.1(a) provides that an incoming retailer under the Customer Transfer Code (**CT Code**) may lodge a customer transfer request with Western Power with respect to a contestable exit point. With respect to that request, Western Power is required to comply with the CT Code and, except as specified in clause 9, the AQP does not apply.

2606. However, as set out in the Draft Decision, the Authority notes clause 9.1 was not specifically drafted to deal with a supplier of last resort assuming its obligations, and contains provisions that the Authority considers would constrain the ability of a supplier of last resort or a default supplier to meet its obligations.

2607. Under the current AQP, provision is made for an application to bypass the queue when necessary to meet the requirements of section 5.7(g) of the Access Code as there is express provision in clause 24.5(b) and (c) of the AQP, which has the effect of permitting bypass of the AQP first-come, first-served principle to the extent necessary to allow a supplier of last resort and/or a default supplier to comply with their obligations.

2608. The Authority considers that, to avoid any doubt about the intention or effect of clause 9.1, a specific clause in similar terms to clauses 24.5(b) and (c) should be reinstated in the AQP to comply with Draft Decision Amendment 76.

Required Amendment 55

The applications and queuing policy must be amended to include a specific clause in similar terms to clauses 24.5(b) and (c) of the current access arrangement.

Facilitation of Part 9 of the Act

2609. Section 5.7(h) of the Access Code requires that an AQP must facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the "market rules" as defined in section 121(1) of the Act.

2610. Part 9 of the Act deals with establishing a wholesale electricity market and provides the head of power for the Market Rules. Section 5.7(h) requires, in practical terms, that the AQP facilitate the operation of the wholesale electricity market.

2611. The current access arrangement is based on a first-come first-served queuing principle. As the queuing rules were materially the same as the queuing rules under clauses A2.45 and A2.50 of the model AQP under the Access Code, section 5.11 of the Access Code required the Authority to determine that the first-come first-served queuing principle of the AQP is consistent with the Code objective.

2612. Notwithstanding that the Authority was required to determine that the first-come first-served queuing rules met the requirements of the Access Code, the Authority considers that the first-come first served queuing rules under the AQP, in combination with the structure of the wholesale electricity market and reserve capacity mechanism, do not serve to promote efficient investment in the electricity network.

2613. Although the removal of the first-come first-served queuing rules from the proposed revised AQP should lead to an improvement, the Authority considers any deficiencies of the wholesale electricity market and reserve capacity mechanism cannot be fully resolved through the queuing rules in the AQP. As noted in the Authority's final decision for the current access arrangement, this requires consideration in a broader review of regulatory arrangements for the electricity market that considers network planning processes, the functioning of the wholesale electricity market, the treatment of new investment under the Access Code, as well as the AQP.

Priority of access applications lodged before the start of the third access arrangement period

2614. Section 5.7(i) of the Access Code requires that an AQP must, if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.

2615. The proposed AQP involves substantial changes to the current applications and queuing arrangements. This is in the context of there being a substantial number of applications currently being processed by Western Power and queued under provisions of the current AQP.

2616. The Authority notes that Western Power considers existing applications will not be disadvantaged on the basis that under the proposed revised AQP, those applications will not be treated as withdrawn and should be processed in the same time, or less, compared to the existing AQP. Clause 2.4(b) specifically provides that an application made prior to the date of commencement of the proposed revised AQP shall be deemed to have been made under the proposed AQP with a priority date being the date it was given under the current policy.

2617. The Authority considers this view to be reasonable, provided such applicants are also free to pursue an applicant-specific solution if desired. This would enable applicants to either progress their application through the competing applicant group process, which may result in reduced connection costs and thus progress an augmentation, or to continue to pursue an applicant-specific solution, which is in effect the status quo.

2618. As discussed in paragraphs 2525 to 2530, the Authority has required an amendment to ensure the proposed AQP makes provision for an applicant to have an application treated independently of any other application, providing the applicant is prepared to fully fund the solution. The Authority considers that, providing the relevant amendment is made, existing applicants will be no worse off under the proposed revised AQP.

Other matters raised in submissions

2619. Submissions made to the Authority on the proposed AQP address some issues not directly related to the requirements of section 5.7 of the Access Code.

2620. Griffin Energy's submission raises concerns over the ability of an existing user (with specific reference to Verve Energy) to retain contractual rights to unutilised transmission capacity, with a consequent inefficient use of the transmission network. The Authority has previously considered this matter in relation to proposals by Western Power during both the first and second access arrangement reviews for Western Power to have a right to unilaterally reduce a user's contracted capacity where that capacity is unutilised.

2621. The Authority's reasoning included the following points relevant to the concerns raised in Griffin Energy's submission:

- under the regulatory scheme established by the Access Code, where access contracts are based on rights to capacity at entry points and exit points, it would be unreasonable for a user to not be able to enter into a contract for capacity and, subject to continuing to pay the relevant tariffs for that capacity, to continue to hold the contracted capacity regardless of whether that capacity is used or not;
- the ability of a user to hold contracted capacity at entry points or exit points that are unused is consistent with efficient investment in the network as the user will generally make any such decision to hold unused capacity taking into account the cost of that capacity and the value of the option to utilise the capacity at some time in the future;
- under the regulatory scheme applying under the Access Code and where a user may be required to pay capital contributions for an augmentation of the network in order to contract for a certain amount of capacity at an entry or exit point, the ability of a user to hold contracted capacity that is unused is necessary for that user to make efficient decisions for the payment of capital contributions; and
- other remedies exist to address the holding by a user of unused capacity for anticompetitive purposes – the holding by a user of unused capacity for this purpose may constitute hindering or preventing access and be unlawful under section 115 of the *Electricity Industry Act 2004* or otherwise in contravention of Part IV of the *Trade Practices Act (*now the *Competition and Consumer Act 2010)*.[655]

2622. Submissions from Griffin Power, Synergy and Perth Energy raised concerns over the relationship of the AQP with an emerging consideration of whether generation

[655] Economic Regulation Authority, 4 December 2009, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, pp. 62, 63.

should be connected to the network on a constrained or unconstrained basis. As noted in paragraph 178 above, the Authority is aware that consideration is being given to the merits of moving to a constrained network approach, however, this is not an issue within the scope of the access arrangement review process.

2623. In its submission, Pacific Hydro observes that:

> Solutions that meet the needs of a particular competing application group will be charged uniformly across all parties; however some solutions may only be relevant for specific developers resulting in a smearing of augmentation costs. This may not be a desirable outcome for developers who have good connection access.

2624. The Authority recognises that there will potentially be winners and losers in any methodology dealing with capacity augmentations and how the resultant costs are shared. However, to the extent that the proposed AQP results in a more efficient overall solution, then the objectives of the Access Code are better achieved. Furthermore, as discussed above in paragraphs 2525 to 2530 above, applicants will be able to pursue an applicant-specific solution and the Authority has required amendments to the proposed AQP to ensure that is the case.

Drafting Amendments

2625. In its review of the proposed revisions to the AQP the Authority noted a number of drafting issues that require amendment. In its Draft Decision the Authority accordingly required the following amendment to the proposed revisions.

Draft Decision Amendment 77

The proposed revised access arrangement should be amended to incorporate the following drafting amendments:

Definitions

The following phrases must be italicised as they are defined terms:

1. "reasonable and prudent person", wherever it appears in the policy; and
2. "confidential information", at the end of clause 6.1.

Clause 14.4(f)(ii)(B)

The full stop at the end of the clause should not be underlined.

Clause 24.10(a)

The word "unused" should not be italicised and "; and" should be deleted.

Clause 24A.3(b)

The word "its" on line 5 should be amended to "it", so that part of the clause reads:

"......timing, cost and terms of it obtaining access......"

Clauses 24A.3(d) and (e)

The phrase "*Preliminary Access Offer*" on the last line of sub-clause (d), and in all places in sub-clause (e), should be lower case so that the term reads "*preliminary access offer*".

2626. In response to the Draft Decision, Western Power has accepted this amendment and incorporated the revised drafting in the revised proposed revisions to the access arrangement. The Authority is satisfied that the revised proposed revisions adequately reflect Draft Decision Amendment 77.

CONTRIBUTIONS POLICY

Access Code Requirements

2627. A contributions policy sets out the principles and processes for determining when a contribution will be required from a user, including for a network augmentation, and for determining the amount of the contribution. A "contribution" is defined in section 1.3 of the Access Code as a capital contribution, a non-capital contribution or a headworks charge.

2628. Section 5.1(h) of the Access Code requires that an access arrangement include a contributions policy, defined in section 1.3 of the Access Code as a policy in an access arrangement under section 5.1(h) dealing with contributions by users.

2629. The particular requirements for a contributions policy are set out in sections 5.12 to 5.17D of the Access Code:

5.12 The objectives for a contributions policy must be that:

(a) it strikes a balance between the interests of:

(i) contributing users; and

(ii) other users; and

(iii) consumers; and

(b) it does not constitute an inappropriate barrier to entry.

5.13 A contributions policy must facilitate the operation of this Code, including:

(a) sections 2.10 to 2.12; and

(b) the test in section 6.51A; and

(ba) sections 5.14 and 5.17D; and

(c) the regulatory test.

5.14 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; and

(b) must not require a user to make a contribution in respect of any part of non- capital costs which would not be incurred by a service provider efficiently minimising costs; and

(c) may only require a user to make a contribution in respect of required work;

and

(d) without limiting sections 5.14(a) and 5.14(b), must contain a mechanism designed to ensure that there is no double recovery of new facilities investment or non-capital costs.

5.15 A contributions policy must set out:

(a) the circumstances in which a contributing user may be required to make a contribution; and

(b) the method for calculating any contribution a contributing user may be required to make; and

(c) for any contribution:

(i) the terms on which a contributing user must make the contribution; or

(ii) a description of how the terms on which a contributing user must make the contribution are to be determined.

5.16 A contributions policy may:

(a) be based in whole or in part upon the model contributions policy, in which case, to the extent that it is based on the model contributions policy, any matter which in the model contributions policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model contributions policy; and

(ii) sections 5.12 to 5.15; and

(iii) the Code objective;

and

(b) be formulated without any reference to the model contributions policy and is not required to reproduce, in whole or in part, the model contributions policy.

5.17 The Authority:

(a) must determine that a contributions policy is consistent with sections 5.12 to 5.15 and the Code objective to the extent that it reproduces without material omission or variation the model contributions policy; and

(b) otherwise must have regard to the model contributions policy in determining whether the contributions policy is consistent with sections 5.12 to 5.15 and the Code objective.

5.17A Despite section 5.14, Electricity Networks Corporation may require a contribution for Appendix 8 work of up to the maximum amount determined under Appendix 8 for the relevant type of Appendix 8 work.

5.17B From 1 July 2007 until the first revisions commencement date for the Western Power Network access arrangement, section 5.17A prevails over any inconsistent provisions of the Western Power Network access arrangement.

5.17C Despite section 5.14, the Authority may approve a contributions policy that includes a “headworks scheme” which requires a user to make a payment to the service provider in respect of the user’s capacity at a connection point on a distribution system because the user is a member of a class, whether or not there is any required work in respect of the user.

5.17D A headworks scheme must:

(a) identify the class of works in respect of which the scheme applies, which must not include any works on a transmission system or any works which effect a geographic extension of a network; and

(b) not seek to recover headworks charges in an access arrangement period which in aggregate exceed 1 per cent of the distribution system target revenue for the access arrangement period; and

(c) identify the class of users who must make a payment under the scheme; and

(d) set out the method for calculating the headworks charge, which method:

(i) must have the objective that headworks charges under the headworks scheme will, in the long term, and when applied across all users in the class referred to in section 5.17D(c), recover no more than the service provider's costs (such as would be incurred by a service provider efficiently minimising costs) of any headworks; and

(ii) must have the objective that the headworks charge payable by one user will differ from that payable by another user as a result of material differences in the users' capacities and the locations of their connection points, unless the Authority considers that a different approach would better achieve the Code objective; and

(iii) may use estimates and forecasts (including long term estimates and forecasts) of loads and costs; and

(iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs; and

(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

Current Access Arrangement

2630. A contributions policy is contained in Appendix 3 of the current access arrangement.

Proposed Revisions

2631. In the access arrangement information, Western Power stated that its proposed revisions to the contributions policy will see no material departure to the current form and operation of the policy. Western Power proposed the following revisions:

- clause 5.2(a) of the contributions policy has been revised such that any headworks costs associated with a headworks scheme and any incremental revenue taken account of by the new facilities investment test are excluded when contributions payable are calculated;

- clause 6(e) of the contributions policy, which stated that when calculating a headworks contribution the amount likely to be recovered as new revenue should be deducted, has been deleted;
- section 6 of the Distribution Headworks Methodology has been revised such that the headworks price list will be inflated on an annual basis (using March CPI data) rather than on a quarterly basis and the price list will be reviewed prior to the start of each access arrangement period (based on distribution construction cost estimates) rather than annually; and
- Appendix D of the current Distribution Headworks Methodology has been removed as it relates to a Government rebate subsidy scheme to residential and commercial applications affected by the headworks scheme that is no longer in operation.

2632. Western Power also proposed to introduce a distribution low voltage connection scheme (**DLVCS**), with its original intention being to submit an in-period (current access arrangement) submission to seek approval for the scheme. Western Power prepared its proposed revised access arrangement assuming that the in-period submission would occur prior to it submitting the proposed revised access arrangement and has included the new scheme in its proposed revised contributions policy. This matter is discussed further below.

Submissions

Contributions Policy

2633. In its submission, Perth Energy considers this is an opportune time for the Authority to deal with some of the inefficiencies and complexities it believes have materialised in the capacity market within the WEM flowing directly from the application of Western Power's capital contribution policy as set out in the access arrangement. Perth Energy raises a number of issues with the current capital contribution policy and suggests that a potential way forward would be to move to a shallow-only charging policy. Perth Energy has put forward options around using location specific use of system charges. Perth Energy proposes that if the access is to be used for supply to general retail loads in the SWIS, i.e. without one or more specific foundation loads, then shallow-only charges should apply; if the access is designed for one dedicated load, the entire contribution should be made by that load; and if access is for a mix of dedicated loads and general retail market, then Western Power could apply a shared allocation.

2634. Landfill Gas and Power's submission supports Western Power's proposed changes to the contributions policy.

2635. WALGA submits that timely availability of network capacity to support developments, particularly in regional areas, and the prices proposed by Western Power for network expansion/augmentation are of concern to local authorities. WALGA considers Western Power's ability to be responsive to a dynamic property development market is important to all land developers, including Local Governments.

Headworks Scheme

2636. A submission from the Office of Energy notes that Western Power explicitly states that "[the] methodology explains how the requirements of sections 5.17D(i), (ii) and (iii) [of the Access Code] have been met in the contributions policy but makes no mention of the requirements under 5.17D(d)(iv) and (v)" and queries Western Power's reasons for not considering these requirements.

2637. The Office of Energy also considers it would be helpful if Western Power provided reasoning for its amendments to the Code definitions of "transmission system" and "distribution system" in its Distribution Headworks Methodology.

Distribution Low Voltage Connection Scheme Methodology

2638. Synergy's submission notes that a proposed Code amendment allowing for an increase in the headworks charges that Western Power may directly recover from consumers who are subject to Western Power's proposed DLVCS, is yet to be approved and hence the scheme should not be considered as part of the third access arrangement revisions.

2639. The National Electrical and Communications Association supports the proposed DLVCS as providing greater transparency whilst removing the disparity in pricing for customers who request the same scope of works yet are charged very different prices.

2640. Submissions from FINBAR and the Property Council of Australia both raise similar points and are concerned particularly with the potential impact on the competitiveness of multi-unit development in Western Australia. Specific points raised include:

- there is no effective means to gauge the risk of having clause 7.5 of the contributions policy (exclusion from DLVCS) applied to a project, thus providing no certainty to a developer when considering the initial feasibility of a project;
- the revenue offset is not clearly set out and the current arrangements include the inequitable exclusion of multi-residential developments from having a revenue offset applied to the headworks costs; and
- the formula to be used for calculating the level of security.

2641. The Office of Energy's submission raised some points relating to drafting:

- The contributions policy defines "headworks scheme" as meaning "the scheme described in clause 6 of this *contributions policy*". Clause 6 only refers to the distribution headworks scheme. This definition therefore does not include Western Power's distribution low voltage connection scheme, which is described in clause 7 of the contributions policy.
- The Distribution Headworks Methodology states that "headworks has the same meaning given to it in the contributions policy". However, the definition in the DLVCS Methodology does not contain the reference to HV (or high voltage) which is referred to in the contributions policy definition. The high voltage reference may have implications for the classification of the proposed DLVCS as a headworks scheme.

Considerations of the Authority

2642. In considering the proposed revised contributions policy, the Authority has given attention to the revisions proposed by Western Power as well as to whether, in view of practical experience, the provisions of the capital contributions policy under the current access arrangement are consistent with the requirements of the Access Code. In doing so, the Authority has had regard to submissions made on the proposed access arrangement revisions. The considerations of the Authority are set out below under the following headings:

- current provisions of the capital contributions policy; and
- proposed revisions to the contributions policy.

2643. As noted by Synergy, at the time of the Draft Decision, the Access Code did not permit the proposed DLVCS as it fell above the threshold set for such schemes in section 5.17D(b) of the Code. The Authority was unable to approve the scheme until such an amendment was made.

2644. In the Draft Decision, the Authority noted it was aware that a proposed Access Code amendment was being considered for approval and that, once the amendment was gazetted, consideration would be given to the proposed scheme. In the interim, the Authority drew attention to the points raised in public submissions in relation to the proposed scheme and recommended that Western Power continue to work with stakeholders to resolve any issues.

2645. As the Authority was unable to approve the proposed distribution low voltage scheme, the Draft Decision required the following amendment:

Draft Decision Amendment 78

The proposed revised access arrangement must be amended to delete all reference to the proposed distribution low voltage scheme.

2646. An amendment to section 5.17D(b) of the Access Code was gazetted on 13 April 2012, which enabled the Authority to give consideration to the proposed scheme. As part of an intra-period assessment of the variation to the current access arrangement pursuant to section 4.41A of the Access Code the Authority published an issues paper and called for public submissions on 18 May 2012. The Authority published a draft decision on 3 July 2012 and a final decision on 3 September 2012.

2647. As the DLVCS has been approved as a mid-period variation to Western Power's current access arrangement, the proposed revisions to the access arrangement need to be amended to reflect the Authority's published *Final Decision on Proposed variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy*.

Required Amendment 56

The proposed revisions to the access arrangement must be amended to reflect the Authority's published *Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy* and any consequential amendments.

Current Provisions of the Capital Contributions Policy

2648. Perth Energy's submission to the Authority on the proposed access arrangement revisions indicate that there are practical difficulties with broad principles and particular provisions of the current capital contributions policy that are proposed to be maintained in the contributions policy for the third access arrangement period. The particular matters raised by Perth Energy include:

- inefficiencies and complexities it believes have materialised in the capacity market within the WEM flowing directly from the application of Western Power's capital contribution policy as set out in the access arrangement;
- issues with the current capital contribution policy and a suggestion that a potential way forward would be to move to a shallow-only charging policy;
- options around using location specific use of system charges; and
- a proposal that if the access is to be used for supply to general retail loads in the SWIS (that is,. without one or more specific foundation loads), then shallow-only charges should apply. If the access is designed for one dedicated load, the entire contribution should be made by that load. If access is for a mix of dedicated loads and general retail market, then Western Power could apply a shared allocation.

2649. These matters are interrelated and are addressed by the Authority as follows.

2650. The primary determinant of the amount of a contribution that can be required in respect of new facilities investment to augment a network is the amount of the new facilities investment that does not satisfy the new facilities investment test under section 6.52 of the Access Code. Under section 5.14 of the Access Code, a contributions policy must not require a user to make a contribution in respect of any new facilities investment that meets the new facilities investment test, with the exception of contributions required under a "headworks scheme" or new facilities investment for works of certain types specified in Appendix 8 of the Access Code.

2651. Where the provision of a service to a user will require works for "deep" augmentation of a network, the amount of a contribution to be required in respect of the new facilities investment for these works will depend upon how much of the new facilities investment is determined as meeting the new facilities investment test.

2652. The current capital contributions policy and the proposed contributions policy are consistent with this requirement as clause 2(c)(i) provides that a contribution in respect of new facilities investment may only be required in respect of an amount that does not meet the new facilities investment test.

2653. In determining the amount of a contribution to be required in respect of new facilities investment, other than for exceptions set out in Appendix 8 of the Access

Code and under a headworks scheme, Western Power must determine the amount of the new facilities investment that meets the new facilities investment test. As Western Power may only require contributions in respect of new facilities investment that does not satisfy the test, this ensures there is no double recovery of the costs of the new facilities investment.

2654. Applying the new facilities investment test for the purposes of determining the amount of a contribution involves addressing the individual components of the test:

- ensuring that the forecast amount of the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs;
- determining whether the amount of anticipated incremental revenue for the new facility (which would include incremental revenue from both the user potentially liable for the contribution and from other users of the network) is expected to at least recover the forecast amount of the new facilities investment;
- determining whether all or part of the new facilities investment falls under a "modified test" under sections 6.52(b)(i)B and 6.53 of the Access Code;
- determining the nature and value of any net benefits arising from the new facilities investment, which might be diverse in nature and include such benefits as, for example, increased reliability of network services and improved outcomes in electricity markets; and
- determining whether the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

2655. While not expressed to this level of detail in the proposed contributions policy, the Authority is satisfied that these requirements are implicit in the provisions of clause 5.2 of the proposed contributions policy that sets out the calculation of a contribution and that indicates that a contribution in respect of new facilities investment excludes any amount that meets the new facilities investment test.

Current Provisions of the Headworks Scheme

2656. The Office of Energy notes that Western Power explicitly states that "[the] methodology explains how the requirements of sections 5.17D(d)(i), (ii) and (iii) [of the Access Code] have been met in the Contributions Policy. It makes no mention of the requirements under 5.17D(d)(iv) and (v)." The Office of Energy has queried Western Power's reasons for not considering these requirements, which are in the following terms:

> 5.17D(d) (iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs
>
> 5.17D (d)(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

2657. In its final decision for the current access arrangement, the Authority required the following:

Final Decision Amendment 42

The proposed access arrangement revisions should be amended such that clause 6 of the contributions policy sets out:

- the method or calculation and assumptions applied in determining the amount of costs to be recovered by headworks contributions;
- the method or calculation and assumptions applied in determining the allocation of costs across a forecast of connections to the network and determining the magnitude of headworks contributions;
- the procedures or methods applied by Western Power to ensure that headworks contributions will, in the long term, recover no more than Western Power's costs of the headworks; and
- a mechanism, which may involve a system of accounting records, to ensure that any amount of the costs of the headworks recovered by headworks contributions are not also recovered, or sought to be recovered, through other contributions or through tariffs for services.

2658. In response to the final decision on the second (current) access arrangement, Western Power:

- amended clause 6 of the contributions policy to reference a new appendix to the access arrangement (Appendix 9 – Distribution Headworks Methodology, relabelled as Appendix C.2 in the proposed revised access arrangement), which set out the method used to determine the headworks prices that may apply under the contributions policy;
- amended clause 6.2(b) of the contributions policy to indicate that where a headworks contribution is made by an applicant, no further contribution should be required from the applicant in respect of headworks; and
- added a new clause 6.2(c) to the contributions policy, which stated that a headworks contribution is a capital contribution (as defined in the Access Code).

2659. In its further final decision for the current access arrangement, the Authority was satisfied that the appendix adequately set out the method for calculating the headworks charge. The Authority was also satisfied that the amendment to clause 6.2(b) adequately ensured that headworks funded under the headworks scheme are not also funded by other contributions from users. Furthermore, the Authority noted that, taking into account the requirements under section 6.51A of the Access Code for consideration of capital contributions in adding amounts of new facilities investment to the capital base, the Authority was satisfied that clause 6.2(c) prevented any amount of headworks costs that are financed by headworks contributions from also being recovered through tariffs for services.[656]

[656] Under this provision, Western Power is required to ensure that headworks charges are deducted from new facilities investment in determining the amount of new facilities investment that can be added to Western Power's regulated capital base (that is, the amount of new facilities investment that satisfies the new facilities investment test). This is in accordance with the general scheme proposed by Western Power for the treatment of capital contributions in determining its regulated capital base.

2660. The Authority continues to be satisfied, for the above reasons, that appropriate mechanisms are in place to ensure there is no double recovery of costs in relation to headworks costs and contributions as required by section 5.17D(d)(iv).

2661. With regard to section 5.17D(d)(v), the Authority notes there is no requirement under the Access Code for a headworks scheme to include a rebate mechanism or a mechanism to retrospectively adjust for differences between forecast and actual values.

2662. The Office of Energy's submission queries the definitions of "distribution system" and "transmission system" in the distribution headworks methodology. The Authority notes these definitions are unchanged from the current access arrangement and are consistent with Western Power's contributions policy.

Proposed Revisions to the Contributions Policy

2663. The Authority's consideration on Western Power's proposed revisions to the contributions policy and distribution headworks methodology is set out below.

Calculation of Contributions Payable

2664. Western Power notes that it has amended clauses 5.2(a) and 6(e) of the contributions policy to more clearly relate the method of calculation of contributions under the contributions policy to the operation of the distribution headworks methodology. The proposed amendments are underlined as follows:

> 5.2 The contribution payable in respect of any works to which this policy applies is calculated by:
>
> (a) determining the appropriate portion of any of the forecast costs of the works (<u>excluding headworks with respect to the headworks scheme</u> …) which do not meet the new facilities investment test (<u>excluding, to avoid doubt, the incremental revenue test as per section 6.52(b)(i)(A) of the Code</u>)…
>
> …
>
> (e) deducting the amount likely to be recovered in the form of new revenue gained from providing covered services to the applicant, or, if the applicant is a customer, to the customer's retailer, as calculated over the reasonable time, at the contributions rate of return…

2665. Western Power states clause 5.2(a) has been revised to make clear that any headworks costs associated with a headworks scheme are excluded when calculating contributions under the contribution policy. As such, costs will be covered by headworks contributions and it would be double counting to also include them in an assessment of a contribution under the contribution policy.

2666. Western Power states the amendment to clause 5.2(a) in relation to incremental revenue is to make clear that incremental revenue is only deducted at clause 5.2(e) and not at clause 5.2(a) as well, as this would result in double counting.

2667. The Authority agrees that the amendments proposed by Western Power to clause 5.2 serve to clarify the intention of the policy.

2668. Western Power proposed deleting clause 6.3(e) of the contributions policy, which stated that, when calculating a headworks contribution, the amount likely to be recovered as new revenue should be deducted. Western Power states that the text should be removed to avoid an impression that the calculation of a headworks contribution should deduct expected new tariff revenue from the forecast costs in the calculation of a headworks contribution. Western Power considers this is necessary because expected new tariff revenue is deducted from forecast costs in the calculation of contributions under the contributions policy and so should not also be deducted again through the distribution headworks methodology.

2669. The Authority agrees the proposed deletion of section 6.3(e) is appropriate to avoid the suggestion that new tariff revenue is included twice in the calculation of contributions. However, the distribution headworks methodology, in particular Appendix C, *Revenue Offsets*, is still potentially confusing as it notes that price lists for headworks charges take into account standard revenue offsets.

2670. The Authority accordingly required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 79

The Distribution Headworks Methodology and Contribution Policy must clarify how revenue offsets are calculated and how they are taken account of when determining headworks contributions.

2671. In response to the Draft Decision, in its amended access arrangement information, Western Power accepts that there would be some benefit in implementing the Authority's amendment and has varied the distribution headworks methodology and the contributions policy accordingly.

2672. The Authority notes that Western Power's revised proposed revisions to the access arrangement have introduced a new term "headworks base charge" to the contributions policy. The "headworks base charge" reflects the cost charged to the customer before deducting incremental revenue to arrive at the headworks contribution. Western Power has also significantly expanded Appendix C of the distribution headworks methodology to better explain how incremental revenue is calculated and at what point it is deducted from the headworks base charge to arrive at the capital contribution. The Authority considers Western Power's amendments adequately deal with the requirements of Draft Decision Amendment 79.

2673. However one minor drafting amendment is required to the first line of clause 6.3 of the contributions policy to change "headworks contribution" to "headworks base charge".

Required Amendment 57

Clause 6.3 of the contribution policy must be amended as follows:

~~A *headworks contribution*~~ The *headworks base charge* …

Headworks Price List Review Process

2674. Western Power has proposed amendments to simplify and reduce the time and resources needed to update the headworks price list. Western Power considers the current requirement to adjust prices quarterly and review cost estimates annually is excessive given the revenue generated (around $1 million to $2 million annually) and the substantial time and resources involved in conducting a review of distribution construction cost estimates. Western Power notes that a review of the distribution headworks methodology distribution construction cost estimates takes a network planner around three months to complete.

2675. Western Power has proposed that the headworks price list will be:

- inflated for CPI on an annual basis; and
- reviewed prior to the commencement of each access arrangement period based on distribution cost estimates, to ensure that movements in costs or efficiencies have been accounted for within prices.

2676. In the Draft Decision the Authority agreed there should to be an appropriate balance between the need to update prices to reflect changes in the underlying cost structures and the effort and cost involved in the price setting process. For the level of revenue involved the current amount of effort, as outlined by Western Power, would appear to be greater than required.

2677. On that basis, the Authority considered Western Power's proposal to index prices each year by CPI and review the level of charges at each access arrangement review is reasonable.

2678. However, the Authority considered this process would be more transparent if the charges were set out in the distribution headworks methodology and an explanation given of any significant changes to those charges.

2679. The Authority, accordingly, required the following amendment to the proposed revised access arrangement.

Draft Decision Amendment 80

The Distribution Headworks Methodology must include a copy of the relevant price lists together with an explanation of any significant changes to those charges compared with the previous period.

2680. In response to the Draft Decision, in its amended access arrangement information Western Power agrees with the Authority's decision and notes that the distribution headworks methodology will include a copy of the relevant price lists as well as an explanation of any significant changes to those charges compared with the previous period.

2681. The Authority notes that Western Power has included an additional appendix to the distribution headworks methodology (*Appendix D - Current prices and explanation of charges*). The appendix states that "prices have not varied compared to the previous access arrangement period" and includes tables setting out the prices that will apply at the commencement of the third access arrangement. However, the appendix refers readers to the Western Power website for the latest prices. The Authority is concerned that some interested parties may have difficulty in locating the relevant tables on the website and, therefore, requires Western Power to provide more specific information in Appendix D to enable the relevant tables to be found easily on Western Power's website.

2682. Aside from this matter, the Authority considers the revised proposed revisions to the access arrangement adequately deal with the requirements of Draft Decision Amendment 80.

Required Amendment 58

Western Power's proposed *Appendix D - Current prices and explanation of charges* needs to include sufficient detail to enable readers to locate the relevant price tables on Western Power's website.

Appendix D of Distribution Headworks Methodology

2683. Appendix D of the current distribution headworks methodology relates to a Government rebate subsidy scheme to residential and commercial applications affected by the headworks scheme that is no longer in operation.

2684. On the basis of Western Power's advice that the Government rebate subsidy scheme for residential and commercial applications affected by the headworks scheme is no longer in operation, the Authority agrees the current Appendix D is no longer required.

TRANSFER AND RELOCATION POLICY

Access Code Requirements

2685. Section 5.1(i) of the Access Code requires that an access arrangement include a transfer and relocation policy. The particular requirements for a transfer and relocation policy are set out in sections 5.18 to 5.24 of the Access Code:

5.18 A transfer and relocation policy:

(a) must permit a user to make a bare transfer without the service provider's consent; and

(b) may require that a transferee under a bare transfer notify the service provider of the nature of the transferred access rights before using them, but must not otherwise require notification or disclosure in respect of a bare transfer.

5.19 For a transfer other than a bare transfer, a transfer and relocation policy:

(a) must oblige the service provider to permit a user to transfer its access rights and, subject to section 5.20, may make a transfer subject to the service provider's prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.20, may specify circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.19(a).

5.20 Under a transfer and relocation policy, for a transfer other than a bare transfer, a service provider:

(a) may withhold its consent to a transfer only on reasonable commercial or technical grounds; and

(b) may impose conditions in respect of a transfer only to the extent that they are reasonable on commercial and technical grounds.

5.21 A transfer and relocation policy:

(a) must permit a user to relocate capacity at a connection point in its access contract to another connection point in its access contract, (a 'relocation') and, subject to section 5.22, may make a relocation subject to the service provider's prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.22, may specify in advance circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.21(a).

5.22 Under a transfer and relocation policy, for a relocation a service provider:

(a) must withhold its consent where consenting to a relocation would impede the ability of the service provider to provide a covered service that is sought in an access application; and

(b) may withhold its consent to a relocation only on reasonable commercial or technical grounds; and

(c) may impose conditions in respect of a relocation only to the extent that they are reasonable on commercial and technical grounds.

5.23 An example of a thing that would be reasonable for the purposes of sections 5.20 and 5.22 is the service provider specifying that, as a condition of its agreement to a transfer or relocation, the service provider must receive at least the same amount

> of revenue as it would have received before the transfer or relocation, or more revenue if tariffs at the destination point are higher.
>
> 5.24 Section 5.23 does not limit the things that would be reasonable for the purposes of sections 5.20 and 5.22.

2686. The Access Code does not provide a model transfer and relocation policy.

Current Access Arrangement

2687. The current access arrangement includes a transfer and relocation policy at Appendix 2.

2688. The transfer and relocation policy of the current access arrangement is indicated at clause 2.1 to apply to any access contract unless otherwise explicitly stated in the access contract, and includes:

- definitions of terms and rules of interpretation (clause 1);
- indication that the transfer and relocation policy applies to any access contract unless otherwise explicitly stated in the access contract (clause 2) and prohibition of any transfer of rights under an access contract except as allowed for under the transfer and relocation policy (clause 3);
- provision for bare transfers of rights under an access contract (clause 4);
- provision for assignments of rights under an access contract other than a bare transfer, subject to consent of Western Power (clause 5); and
- provision for a relocation by a user of contracted capacity at one connection point to another connection point, where the user has an access contract for both connection points (clause 6).

Proposed Revisions

2689. Western Power has moved the transfer and relocation policy to Appendix D of the proposed revised access arrangement but otherwise has not proposed any revisions to the policy. It notes that the policy has had limited use during the current access arrangement and that it has not identified any problems with its operation.

Considerations of the Authority

2690. Taking into account that Western Power has not proposed any revisions to the transfer and relocation policy and the absence of any submissions on the policy, the Authority considers that the transfer and relocation policy of the proposed access arrangement revisions are consistent with the requirements of the Access Code.

SUPPLEMENTARY MATTERS

Access Code Requirements

2691. Section 5.1(k) of the Access Code requires that an access arrangement include provisions dealing with supplementary matters under sections 5.27 and 5.28.

2692. Section 5.27 indicates that supplementary matters comprise:

(a) balancing; and

(b) line losses; and

(c) metering; and

(d) ancillary services; and

(e) stand-by; and

(f) trading; and

(g) settlement; and

(h) any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Code objective.

2693. Section 5.28 of the Access Code requires that the supplementary matters be dealt with in the access arrangement in accordance with other relevant regulatory requirements including written laws, the Wholesale Electricity Market Rules and the Technical Rules.

Current Access Arrangement

2694. Supplementary matters are dealt with in clauses 10.1 to 10.9 of the current access arrangement, addressing the particular matters listed under section 5.27 of the Access Code. These matters are dealt with by reference to the Wholesale Electricity Market Rules and Metering Code.

Proposed Revisions

2695. In the proposed revised access arrangement, supplementary matters are dealt with in clauses 9.1 to 9.7.1. Western Power has not proposed any revisions from the current access arrangement.

Considerations of the Authority

2696. Taking into account the absence of proposed revisions to the section of the access arrangement dealing with supplementary matters and the absence of submissions addressing this element of the access arrangement, the Authority considers that the proposed access arrangement revisions are consistent with the requirements of sections 5.1(k), 5.27 and 5.28 of the Access Code.

APPENDICES

Appendix 1: Summary of Required Amendments

Required Amendment 1

Western Power must remove criteria 4) a) from its proposed eligibility criteria for each reference service.

Required Amendment 2

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems.

Required Amendment 3

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in second last row of Table 6 and Table 7).

Required Amendment 4

Network control services must be excluded from operating cost forecasts for the purposes of determining target revenue and the D-factor scheme must be modified to include network control services.

Required Amendment 5

The revised proposed access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 43 and Table 44

Required Amendment 6

The revised proposed access arrangement must be amended to reflect a forecast of operating expenditure as indicated by the Final Decision values in Table 52.

Required Amendment 7

The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to the cancelled or deferred projects identified in the statutory account audit.

Required Amendment 8

The proposed revised access arrangement must be amended to reflect the values shown in Table 57 above.

Required Amendment 9

Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

Required Amendment 10

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be inflated using the same methodology as the current access arrangement and must not include the additional half year inflation in relation to expenditure during the second access arrangement proposed by Western Power.

Required Amendment 11

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 64 and Table 65 above.

Required Amendment 12

The revised proposed access arrangement revisions must be amended to remove all stay wire programs from the investment adjustment mechanism.

Required Amendment 13

The revised proposed access arrangement revisions must be amended to include the investment adjustment mechanism values as indicated in Table 99.

Western Power's revenue model must also be amended to include a separate regulatory category for wood pole management .

Required Amendment 14

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as set out in Table 119 above.

Required Amendment 15

In relation to Rate of Return, Table 63 of the Amended Access Arrangement Information must be amended to reflect the relevant values of CAPM and WACC parameters in Table 126 and Table 127 of this Final Decision

Required Amendment 16

No amounts in relation to tax on capital contributions may be included in Target Revenue.

Required Amendment 17

The amounts included in target revenue for working capital must be amended to the values in Table 137 and Table 138.

Required Amendment 18

The Authority requires that Western Power adopt a tax asset base derived from the regulatory accounts for the purposes of determining its forecast tax liabilities and its maximum annual revenue requirement.

Required Amendment 19

The correction factor for under-recovery or-over recovery of revenue in the 2012/13 Price List must be based on the actual revenue for 2011/12.

Required Amendment 20

Western Power's amendments for corrections to the real value of the TEC must be removed from the distribution revenue correction factor set out in section 5.7.7 of the revised proposed revisions to the access arrangement.

Required Amendment 21

The reward in relation to the service standard adjustment mechanism must be amended to use the Authority's approved post tax WACC of 3.6 per cent).

Required Amendment 22

The service standard adjustment mechanism in target revenue must be updated to reflect actual service standard performance for 2011/12.

Required Amendment 23

The minimum standard Circuit Availability SSB should be set at 97.7 per cent. This is the estimated 97.5 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during the third access arrangement period.

Table 184 below provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed and radial circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and
- Average Outage Duration, measured in minutes.

Required Amendment 24

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed and radial circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of 0.1 to 1 minute duration and greater than 1 minute duration; and
- Average Outage Duration, measured in minutes.

Table 184 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).

Required Amendment 25

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

Required Amendment 26

Western Power is required to adopt the SAIDI and SAIFI service standard benchmark measures estimated by the Authority from the most recent three years of data (Table 185 provides the Authority's estimates – see Appendix 3 for detail).

Required Amendment 27

Table 186 provides the Authority's estimates – see Appendix 3 for detail).

Required Amendment 28

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Final Decision.

Required Amendment 29

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended as follows:

5.6.1 The *transmission system* revenue cap for *revenue cap services* ~~determines~~ is used to determine the maximum transmission *revenue cap service* revenue (MTR_t) for Western Power's *transmission system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement,~~ Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ transmission revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.

5.7.1 The *distribution system* revenue cap for *revenue cap services* ~~determines~~ is used to determine the maximum distribution *revenue cap service* revenue (MDR_t) for Western Power's *distribution system* for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement,~~ Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.

Required Amendment 30

The Price List Information must set out details of rebalancing between reference services and the reasons for it with supporting information.

Required Amendment 31

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Final Decision. Western Power should include sufficient information to enable a comparison with the estimate of incremental and stand-alone costs in the current 2011/12 Price List Information, and to explain any material variations.

Required Amendment 32

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

Required Amendment 33

Western Power must amend the gain sharing mechanism methodology and values to use the scaling factors, including economy of scale factors, and operating costs approved by the Authority in this Final Decision. The actual values used for scaling factors must be independently audited. The audit must be carried out by an independent auditor approved by the Authority, with Western Power managing and funding the audit. The scope of the audit will be determined by the Authority.

Required Amendment 34

Western Power must amend its revised proposed revisions to the access arrangement to include the process for how it will be determined and to what extent there is a relationship between costs savings and the underperformance on service standards as set out in Western Power's amended access arrangement information.

Required Amendment 35

Western Power must amend Table 27 of the access arrangement to be consistent with the Authority's determination of efficient operating costs as set out in this Final Decision.

Required Amendment 36

The Circuit Availability SST should be set at 98.1 per cent. This is the estimated 50 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.

Required Amendment 37

The System Minutes interrupted (radial networks) measure must be retained as a SSAM incentive measure. The SSAM SST for this measure should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see **Table 184** for the Authority's estimates).

Required Amendment 38

The Loss of Supply Event Frequency (0.1 to 1 system minutes and greater than 1 system minutes) and the Average Outage Duration measures must be included as SSAM incentive measures. The SSAM SSTs must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see **Table 184** for the Authority's estimates).

Required Amendment 39

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue;

- adopt the weightings set out in Table 4 to allocate the revenue at risk across the various measures

- take account of the revisions to allowable transmission revenue set out in this Final Decision to calculate the reward and incentive penalty rates.

Required Amendment 40

Western Power must adopt revised SAIDI and SAIFI SSAM SSTs that remove the transmission network events from the estimates. The SSAM SSTs must be set at the 50 per cent PoE level based on the best fit statistical distribution applied to the most recent three years of historic data (see Table 185 for the Authority's estimates).

Required Amendment 41

Western Power must adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Final Decision.

Required Amendment 42

The D-factor scheme must be amended as set out in paragraph 2273 above.

Required Amendment 43

The values in relation to the recovery of deferred revenue stated in section 7.7 of the revised proposed revisions to the access arrangement must be amended to:

$47.7 million ($ as at 30 June 2012) for transmission services; and

$358.3 million ($ as at 30 June 2012) for distribution services.

Required Amendment 44

Clause 3.6(b) and (c) of the ETAC must be amended to clarify that, to the extent the model service level agreement applies, Western Power must comply with any relevant disconnection timeframes in the model service level agreement.

Required Amendment 45

Clause 3.7 of the ETAC must be amended to require Western Power to act "as soon as reasonably practicable" to advise a user of any connections points which have reverted to it as a "default supplier" retailer.

Required Amendment 46

Clause 6.1 of the ETAC must be amended to include an obligation for Western Power to negotiate in good faith and use reasonable endeavours to negotiate a Connection Contract with the designated controller.

Required Amendment 47

Each of the sub-clauses in clause 3.7 of the electricity transfer must be amended to require Western Power to act "as soon as reasonably practicable".

Required Amendment 48

An amendment is required to the ETAC to reflect the amendments set out in paragraph 2461 above.

Required Amendment 49

An amendment is required to the ETAC to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

Required Amendment 50

The AQP must be amended to enable applicants to elect, at the time of application, that they wish the application to be processed as an applicant-specific solution.

Required Amendment 51

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a "competing applications group" will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

Required Amendment 52

Timelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

Required Amendment 53

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

Required Amendment 54

Sections 17A.3 and 17A.4 of the AQP must be amended as set out in paragraph 2591 above.

Required Amendment 55

The applications and queuing policy must be amended to include a specific clause in similar terms to clauses 24.5(b) and (c) of the current access arrangement.

Required Amendment 56

The proposed revisions to the access arrangement must be amended to reflect the Authority's published *Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy* and any consequential amendments.

Required Amendment 57

Clause 6.3 of the contribution policy must be amended as follows:

~~A *headworks contribution*~~ The *headworks base charge* …

Required Amendment 58

Western Power's proposed *Appendix D - Current prices and explanation of charges* needs to include sufficient detail to enable readers to locate the relevant price tables on Western Power's website.

Appendix 2: Target Revenue Calculation (Revenue Model)

The target revenue calculation (revenue model) sets out the Authority's determination and, in the event of inconsistency, the numbers in the calculation prevail over any other statement of these values in this decision.

The numbers in the revenue model are shown to 3 decimal places.

Due to size and formatting, this Appendix is provided as a separate document to this Final Decision and is available from the Authority's website.[657]

[657] Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

Appendix 3 – Setting Service Standard Benchmarks and Service Standard Targets

1. This Appendix reports on the Authority's statistical analysis of reported historical data relating to service standard performance, provided by Western Power. The historical data is either the most recent five years of data (in the case of transmission) or three years of data (in the case of distribution) for each of the required Service Standard Benchmarks (**SSBs**). The data provides the monthly outcomes for the rolling 12 month performance over the period up to and including the 2011-12 year.

2. The SSBs are set at the 97.5 per cent Probability of Exceedence (**PoE**) level, for the case where higher levels reflect higher performance (for example, Circuit Availability), or the 2.5 per cent PoE, for those cases where lower levels reflect higher performance (for example, SAIDI). The Service Standard Targets (**SSTs**) for the Service Standard Adjustment Mechanism (**SSAM**) are set at the 50 per cent PoE level.

Method

3. The SSBs and SSTs are calculated through the following steps:

- establishing the data series relating to historic service standard performance;
- determining the statistical distribution of best fit using the Minitab software package, using the following choice criteria:[658]
  - the p value must be greater than 0.05 – the higher the p value the more likely that the statistical distribution in question contains the observed data and the statistical distribution is not rejected (that is, the null hypothesis that the distribution matches the data is not rejected);
  - the lowest Anderson-Darling test statistic (provided that the p value is greater than 0.05) – a lower Anderson-Darling test statistic indicates that the data fits the distribution better;
- determining the relevant 2.5 per cent PoE level for the SSB (where a lower value reflects higher performance) or the 97.5 per cent PoE level for the SSB (where a higher value reflects higher performance);
- determining the 50 per cent PoE level for the SST;
- where no statistical distribution is found to fit the data (that is, the p value is less than 0.05 for all statistical distributions examined), then simple 'percentile' analysis is applied (that is, the 50 per PoE is estimated from the median value, and the 2.5 per cent PoE estimated from the mean plus two standard deviations).

Transmission networks SSBs and SSTs

4. The transmission SSBs and SSTs are set out in the following table (Table 192).

658 The Authority in the Draft Decision also examined Box Cox and Johnson transformations. However, these are complex approaches and it is accepted that reverse transformation is not straightforward. Hence, the Authority has not considered these approaches for the Final Decision.

Table 192 Additional transmission SSBs and SSTs for the third access arrangement period

	SSB	SST	Distribution of best fit
Circuit Availability (per cent)	97.9 – 0.2 = 97.7	98.3 – 0.2 = 98.1	Smallest extreme value
System minutes interrupted			
Meshed (minutes)	12.5	8.1	Logistic
Radial (minutes)	5.0	1.9	Percentile estimate
Loss of supply event frequency			
0.1 to 1 minute (events)	33	24	Percentile estimate
Greater than 1 minute (events)	4	2	Percentile estimate
Average outage duration (minutes)	886	698	Weibull

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on data supplied by Western Power

5. The reasons for the choice of each of these distributions of best fit follows.

Circuit Availability

6. The data is not normal, as the p value is less than 0.05 (Table 193). The Smallest extreme value distribution was chosen as the Anderson-Darling statistic is marginally smaller than that for the Weibull distribution.

Table 193 Minitab output for five years of Circuit Availability data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.945	0.016	-
Weibull	0.362	>0.25	-
Smallest extreme value	0.361	>0.25	-

Note: LRT p is the ‘likelihood ratio test p value’ which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

7. With the Smallest extreme value distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 98.3 – used to derive the SST (note that 0.2 per cent is deducted to account for increased outages expected during the third access arrangement – see the main report);
- 97.5 per cent PoE of 97.9 per cent – used to derive the SSB (note that 0.2 per cent is deducted to account for increased outages expected during the third access arrangement – see the main report).

System Minutes Interrupted (meshed circuits)

8. The data is not normal, as the p value is less than 0.05 (Table 194). The Logistic distribution was chosen as it is the only distribution with a p value greater than 0.05.

Table 194 Minitab output for five years of System Minutes Interrupted (meshed circuits) data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.991	0.012	-
Logistic	0.576	0.092	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

9. With the Logistic distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 8.1 minutes – the SST;
- 2.5 per cent PoE of 12.5 minutes – the SSB.

System Minutes Interrupted (radial circuits)

10. The data is not normal, as the p value is less than 0.05 (Table 195). No other distributions examined have a p value greater than 0.05. Accordingly a simple percentile analysis was used to estimate the SSBs and SSTs.

Table 195 Minitab output for five years of System Minutes Interrupted (radial circuits) data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	4.707	<0.005	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

11. With the percentile estimate approach, the resulting PoEs are as follows:

- the median data observation is 1.9 minutes – the SST;

- the mean is 2.23 and the standard deviation is 1.36 – the mean plus 2 standard deviations is 5.0 minutes – the SSB.

Loss of Supply Event Frequency (0.1 to 1 minute)

12. The data is not normal, as the p value is less than 0.05 (Table 195). No other distributions examined have a p value greater than 0.05. Accordingly a simple percentile analysis was used to estimate the SSBs and SSTs.

Table 196 Minitab output for five years of Loss of Supply Event Frequency (0.1 to 1 minute) data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	1.502	<0.005	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

13. With the percentile estimate approach, the resulting PoEs are as follows:

- the median data observation is 24 events – used to derive the SST;
- the mean is 22.45 and the standard deviation is 5.16 – the mean plus 2 standard deviations is 33 events – the SSB.

Loss of Supply Event Frequency (greater than 1 minute)

14. The data is not normal, as the p value is less than 0.05 (Table 197). No other distributions examined have a p value greater than 0.05. Accordingly a simple percentile analysis was used to estimate the SSBs and SSTs.

Table 197 Minitab output for five years of Loss of Supply Event Frequency (0.1 to 1 minute) data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	3.909	<0.005	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

15. With the percentile estimate approach, the resulting PoEs are as follows:

- the median data observation is 2 events – used to derive the SST;
- the mean is 2 and the standard deviation is 0.99 – the mean plus 2 standard deviations is 4 events – the SSB.

Average outage duration

16. The data is normal, as the p value is greater than 0.05 (Table 198). However, the Weibull distribution was chosen as it also has a p value greater than 0.05, and a lower Anderson-Darling test statistic. The three parameter Weibull was not chosen as the likelihood ratio p test of 0.627 is not less than 0.05, and hence the additional parameters do not increase the goodness of fit compared to the Weibull distribution.

Table 198 Minitab output for five years of System Minutes Interrupted (meshed circuits) data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.379	0.394	-
Weibull	0.393	>0.25	
3 parameter Weibull	0.370	0.350	0.627

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

17. With the Weibull distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 698 minutes – the SST;
- 2.5 per cent PoE of 886 minutes – the SSB.

Distribution networks SSBs and SSTs

18. The distribution networks SSBs and SSTs are set out in the following tables (Table 199 and Table 200).

Table 199 Revised Call centre availability SSBs and SSTs for the third access arrangement period (based on 5 years of historic data)

	SSB	SST	Distribution of best fit
Call centre availability (percentage of calls responded to in 30 seconds)	77.5	87.6	Logistic

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on historic data supplied by Western Power

Table 200 Revised SAIDI and SAIFI SSBs and SSTs for the third access arrangement period (based on 3 years of historic data)

	SSB	SST	Distribution of best fit
SAIDI (minutes)			
CBD	39.9	20.3	Percentile
Urban	183.0	136.6	Percentile
Rural short	227.8	207.8	Weibull
Rural long	724.8	582.2	Largest extreme value
SAIFI (events)			
CBD	0.26	0.14	Logistic
Urban	2.12	1.36	2 parameter exponential
Rural short	2.61	2.27	Lognormal
Rural long	4.51	4.06	Lognormal

Note: **SSB** = Service Standard Benchmark; **SST** = Service Standard Adjustment Mechanism Service Standard Target; **AA3** = third access arrangement

Source: Authority analysis, based on historic data supplied by Western Power

19. The reasons for the choice of each of these distributions of best fit follows.

Call centre availability

20. The data is normal, as the p value is greater than 0.05 (Table 201). The Logistic distribution was chosen as it has a distribution with a p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 201 Minitab output for five years of Call centre availability data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.431	0.297	-
Weibull	0.383	>0.25	
Logistic	0.271	>0.25	-

Note: LRT p is the ‘likelihood ratio test p value’ which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

21. With the Logistic distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 87.6 per cent – the SST;
- 97.5 per cent PoE of 77.5 per cent – the SSB.

CBD SAIDI

22. The data is not normal, as the p value is less than 0.05 (Table 202). No other distributions examined have a p value greater than 0.05. Accordingly a simple percentile analysis was used to estimate the SSBs and SSTs.

Table 202 Minitab output for three years of CBD SAIDI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	1.378	<0.005	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

23. With the percentile estimate approach, the resulting PoEs are as follows:

- the median data observation is 20.3 minutes – used to derive the SST;
- the mean is 17.9 and the standard deviation is 10.99 – the mean plus 2 standard deviations is 39.9 minutes – the SSB.

CBD SAIFI

24. The data is normal, as the p value is greater than 0.05 (Table 203). The Logistic distribution was chosen as it has a distribution with a p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 203 Minitab output for three years of CBD SAIFI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.391	0.362	-
Smallest extreme value	0.508	0.203	
Logistic	0.323	>0.25	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

25. With the Logistic distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 0.14 events – the SST;
- 2.5 per cent PoE of 0.26 events – the SSB.

Urban SAIDI

26. The data is not normal, as the p value is less than 0.05 (Table 204). No other distributions examined have a p value greater than 0.05. Accordingly a simple percentile analysis was used to estimate the SSBs and SSTs.

Table 204 Minitab output for three years of Urban SAIDI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	1.956	<0.005	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

27. With the percentile estimate approach, the resulting PoEs are as follows:

- the median data observation is 136.6 minutes – the SST;
- the mean is 139.8 and the standard deviation is 21.6 – the mean plus 2 standard deviations is 183.0 minutes – the SSB.

Urban SAIFI

28. The data is not normal, as the p value is less than 0.05 (Table 203). The 2 parameter exponential distribution was chosen as it is the only distribution with a p value greater than 0.05.

Table 205 Minitab output for three years of Urban SAIFI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	1.161	< 0.005	-
2 parameter exponential	0.967	0.092	0.000

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

29. With the 2 parameter exponential distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 1.36 events – the SST;
- 2.5 per cent PoE of 2.12 events – the SSB.

Rural short SAIDI

30. The data is normal, as the p value is greater than 0.05 (Table 206). The Weibull distribution was chosen as it has a distribution with a p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 206 Minitab output for three years of Rural short SAIDI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.497	0.199	-
Weibull	0.440	>0.25	
Logistic	0.578	0.09	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

31. With the Weibull distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 207.8 minutes – the SST;
- 2.5 per cent PoE of 227.8 minutes per cent – the SSB.

Rural short SAIFI

32. The data is normal, as the p value is greater than 0.05 (Table 207). The Weibull 3 parameter distribution was not chosen because the likelihood ratio test p value is not less than 0.05, and hence it cannot be inferred that this distribution improves on the Weibull distribution given the data. The Lognormal distribution was chosen as it has a distribution with a p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 207 Minitab output for three years of Rural short SAIFI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.385	0.375	-
Weibull	0.519	0.193	-
Weibull 3 parameter	0.367	0.410	0.06
Lognormal	0.380	0.385	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

33. With the Lognormal distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 2.27 events – the SST;
- 2.5 per cent PoE of 2.61 events – the SSB.

Rural long SAIDI

34. The data is not normal, as the p value is just less than 0.05 (Table 208). The Largest extreme value distribution was chosen as it has a distribution with a p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 208 Minitab output for three years of Rural long SAIDI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.744	0.048	-
Weibull 3 parameter	0.564	0.129	0.008
Largest extreme value	0.473	0.236	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

35. With the Largest extreme value distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 582.2 minutes – the SST;
- 2.5 per cent PoE of 724.8 minutes – the SSB.

Rural long SAIFI

36. The data is normal, as the p value is greater than 0.05 (Table 209). The Weibull 3 parameter distribution was not chosen because the likelihood ratio test p value is not less than 0.05, and hence it cannot be inferred that this distribution improves on the Weibull distribution given the data. The Lognormal distribution was chosen as it has a distribution with the highest p value greater than 0.05, and has the lowest Anderson-Darling test statistic.

Table 209 Minitab output for three years of Rural long SAIFI data

Distribution	Anderson-Darling test statistic	p value	LRT p
Normal	0.295	0.578	-
Weibull	0.450	> 0.25	-
Weibull 3 parameter	0.299	> 0.500	0.156
Lognormal	0.295	0.579	-

Note: LRT p is the 'likelihood ratio test p value' which informs whether additional parameters increase the goodness of fit.

Source: Authority analysis, based on data supplied by Western Power

37. With the Lognormal distribution, the resulting PoEs are as follows:

- 50 per cent PoE of 4.06 events – the SST;

- 2.5 per cent PoE of 4.54 events – the SSB.

Appendix 4: Service Performance Data Set

1. The Authority requested that Western Power review the technical aspects of its modelling to inform the choice of the AA3 Service Standard Adjustment Mechanism (**SSAM**), Service Standard Benchmarks (**SSB**s) and Service Standard Targets (**SST**s) (as set out in Appendix 3).[659] The modelling is based on Western Power's performance data (up to and including the recently provided data for the 2011/12 year).

Western Power's response

2. Western Power found no error with the modelling, however, it did raise the following issue:[660]

> The statistical analysis for the Amended Access Arrangement Information in May 2012 used data up to the end of 2010/11, as this was the most recent audited financial-year data available at the time. When preparing the Amended Access Arrangement Information, Western Power modelled the forecast investment to check that it was sufficient to meet the proposed targets. The modelling confirmed that the proposed AA3 investment would result in an expected value of zero under the service standard adjustment mechanism, all things being equal.
>
> Including 2011/12 data in the statistical analysis increases the service standard benchmarks and targets for the AA3 period. Based on the proposed levels of investment during AA3, there is a greater risk of Western Power not achieving these increased targets, and is likely to move the expected value of the service standard adjustment mechanism from zero to negative, inconsistent with the objective of the scheme.

Comparing outcomes

3. The proposed SSAM distribution network targets are set out in Table 179 and Table 180. These are also illustrated graphically in Figure 26 to Figure 33. These show that the distribution SSAM SSTs required by the Authority, based on the dataset three years to 2011-12, are more stringent than those proposed by Western Power, which are based on the dataset three years to 2010-11.[661]

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[659] Economic Regulation Authority 2012, Question FD21, August.

[660] Western Power 2012, Response to question FD21, August.

[661] The Authority notes that there are some small differences due to the statistical distributions adopted, but this issue is second order.

Table 210 Distribution system SAIDI SSAM SSTs (minutes) – AA2 and proposed AA3

	CBD	Urban	Rural short	Rural long
Existing arrangement				
AA2 year ending June 2010 SSAM SST	38	165	259	612
AA2 year ending June 2011 SSAM SST	38	162	253	588
AA2 year ending June 2012 SSAM SST	38	153	244	556
WP proposed following DD				
AA3 financial year proposed SSAM SST (2010-11 dataset)	23	157	221	599
Authority Final Decision				
AA3 financial year proposed SSAM SST (2011-12 dataset)	20	137	209	582

Table 211 Distribution system SAIFI SSAM SSTs (minutes) – AA2 and proposed AA3

	CBD	Urban	Rural short	Rural long
Existing arrangement				
AA2 year ending June 2010 SSAM SST	0.24	1.92	3.12	5.00
AA2 year ending June 2011 SSAM SST	0.24	1.89	3.06	4.85
AA2 year ending June 2012 SSAM SST	0.24	1.83	2.98	4.80
WP proposed following DD				
AA3 financial year proposed SSAM SSTs (2010-11 dataset)	0.14	1.61	2.47	4.21
Authority Final Decision				
AA3 financial year proposed SSAM SSTs (2011-12 dataset)	0.14	1.36	2.27	4.06

Source: Authority analysis based on Western Power data

Figure 26 CBD SAIDI

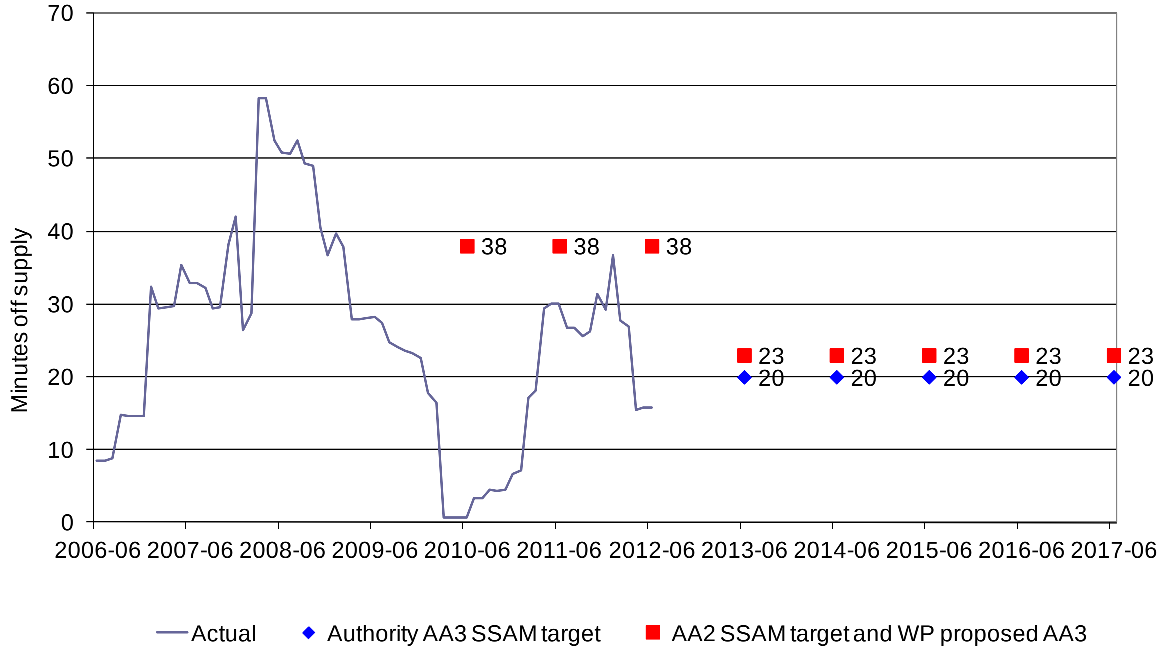


Figure 27 CBD SAIFI

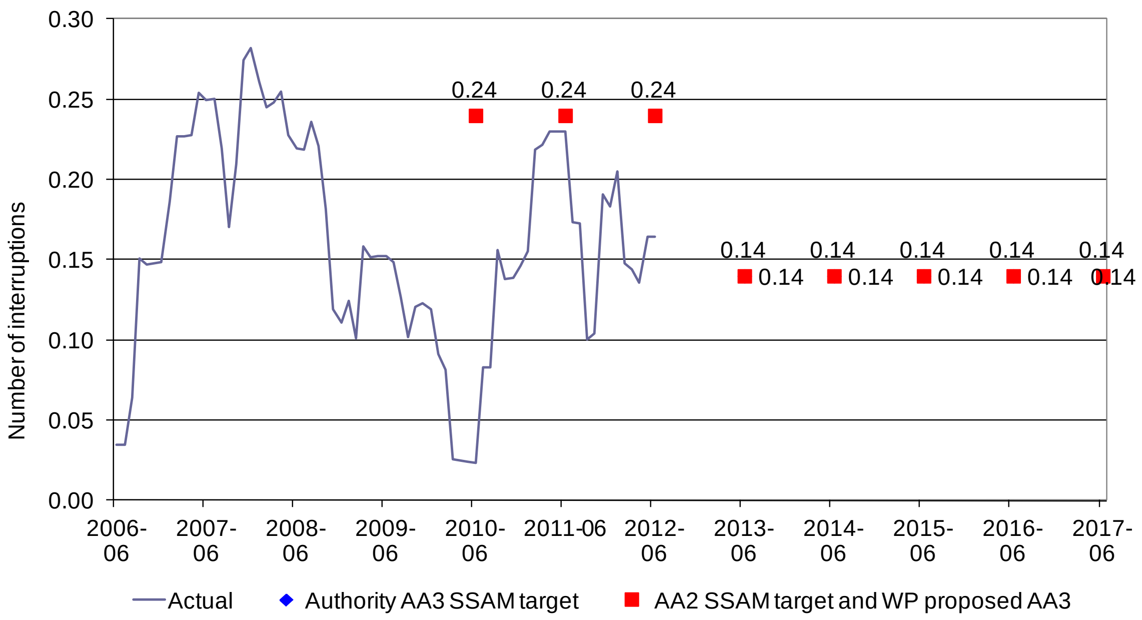


Figure 28 Urban SAIDI

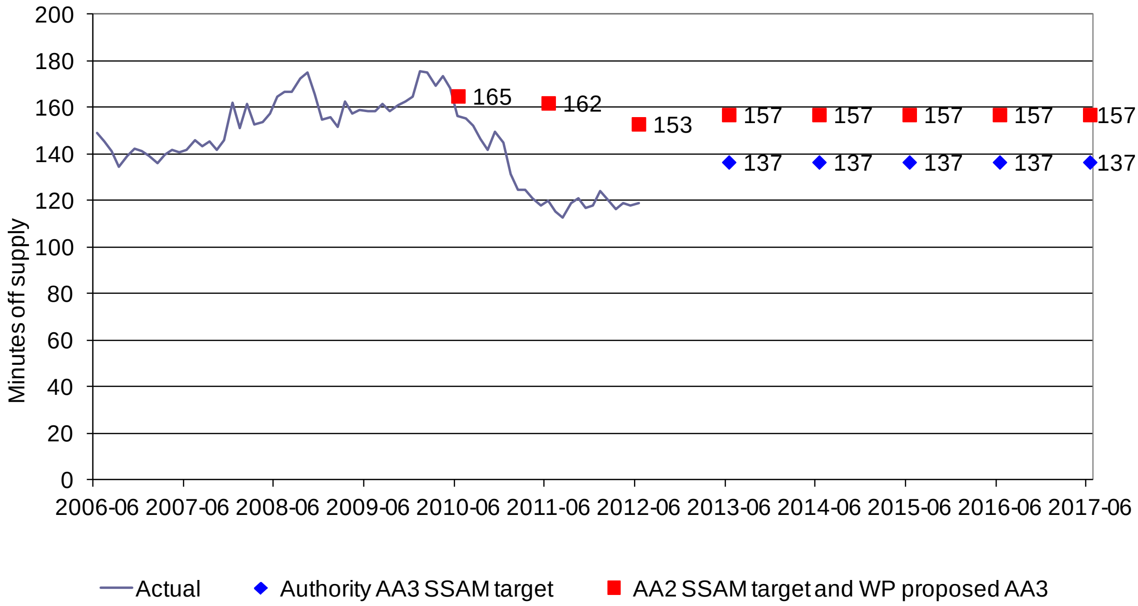


Figure 29 Urban SAIFI

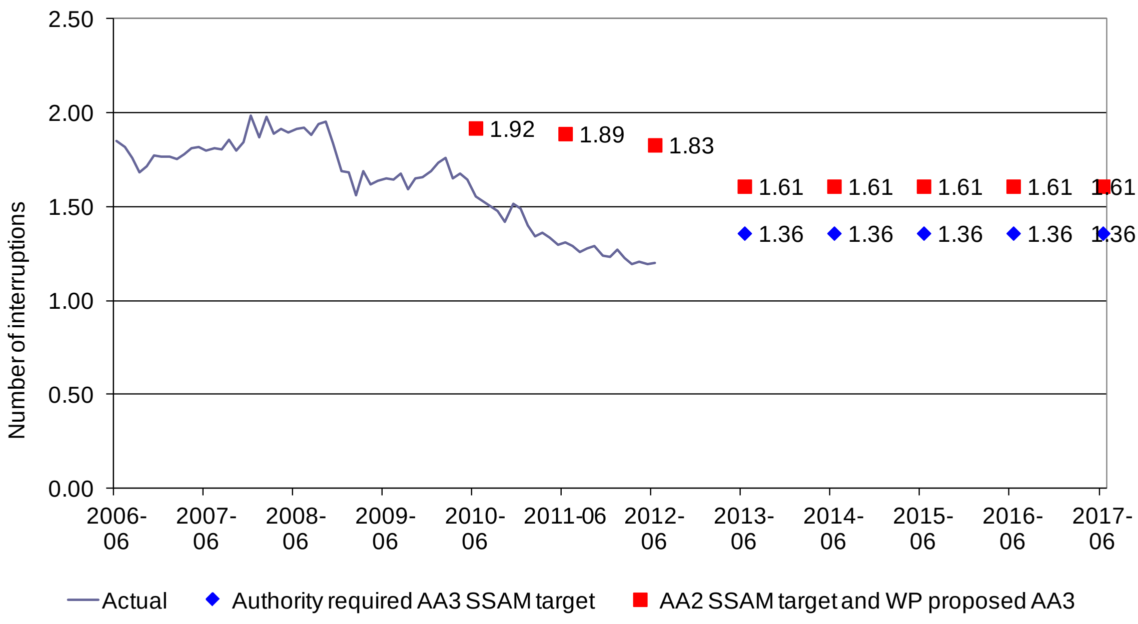


Figure 30 Rural short SAIDI

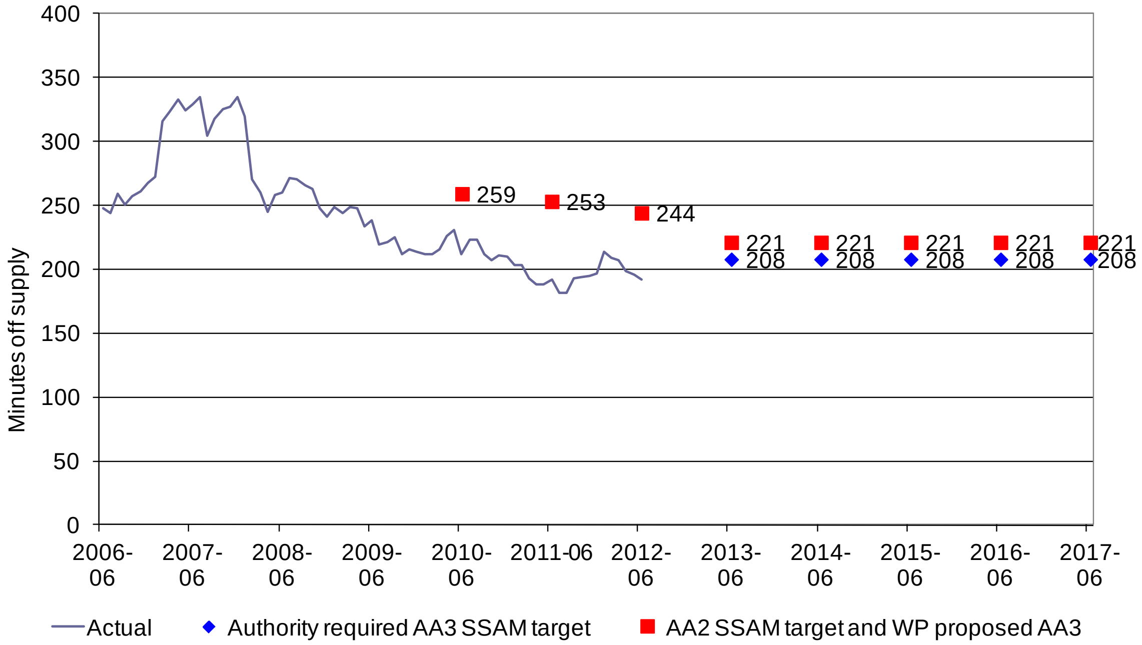


Figure 31 Rural short SAIFI

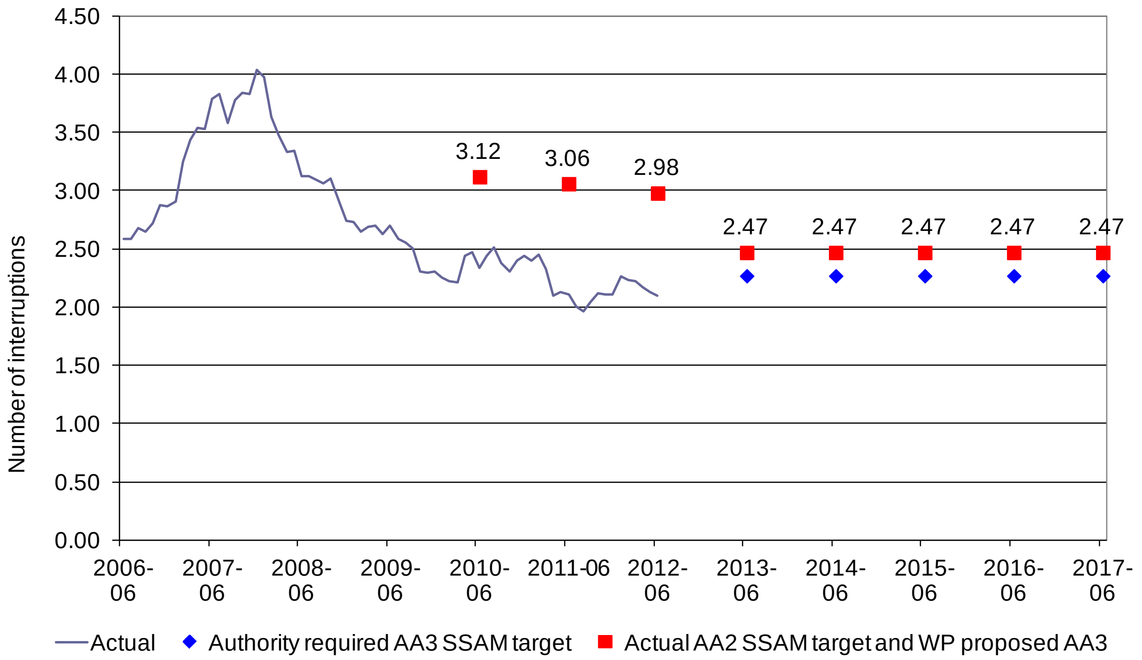


Figure 32 Rural long SAIDI

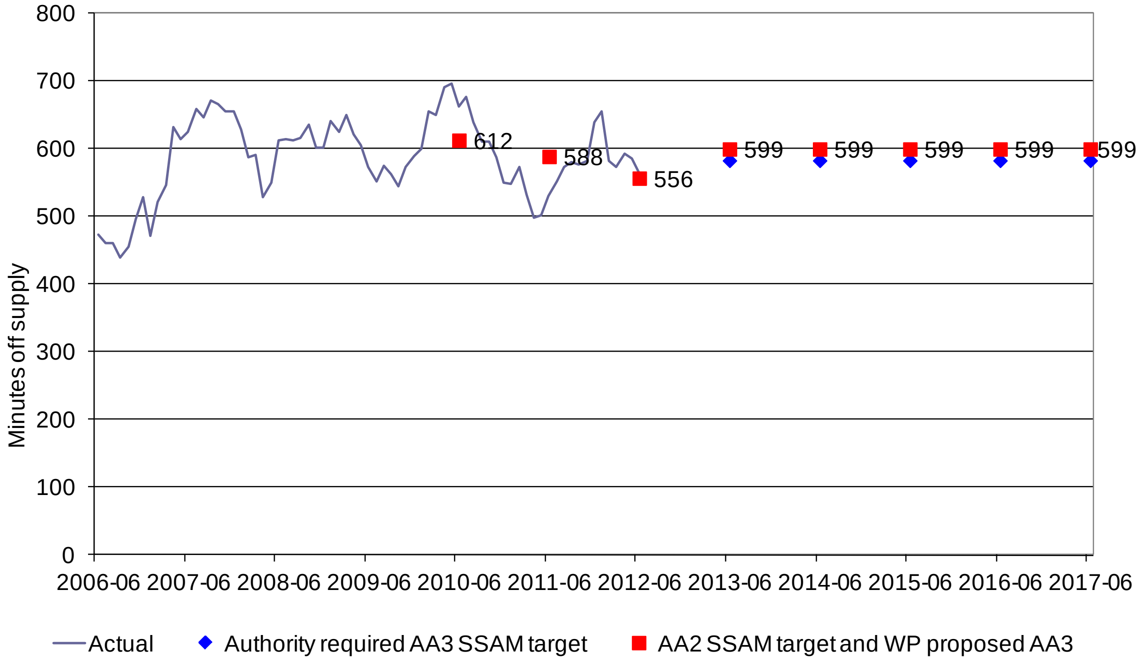
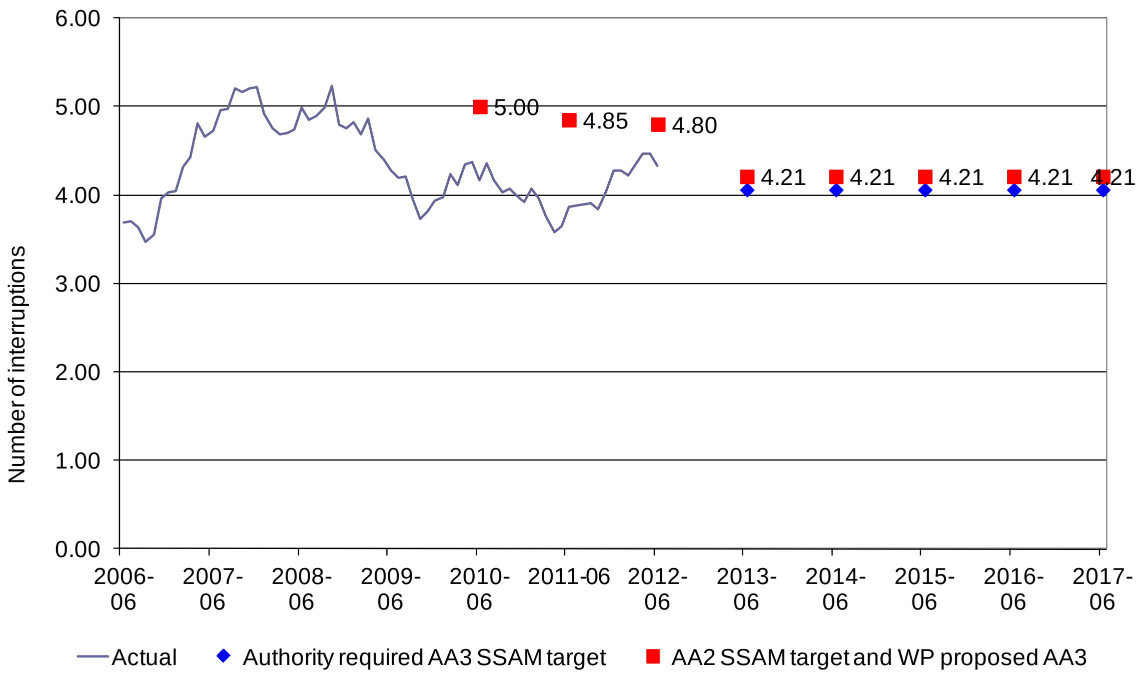


Figure 33 Rural long SAIFI



4. The proposed transmission network SSAM SSTs are set out in Table 212. As may be observed, the move to base the SSTs on the most recent 5 years of data to 2011/12 serves to:

- increase the Circuit Availability SST by 0.1 per cent;
- decrease the System Minutes Interrupted (radial network) SST by 0.1 (not shown in Table);
- decrease the Loss of Supply Event Frequency (0.1 to 1 system minutes) SST by 1 event;
- leave the Loss of Supply Event Frequency (> 1 system minutes) SST unchanged;
- increase significantly the Average Outage Duration SST.

Table 212 Transmission system SSAM SSTs

	AA2 year ending June 2010 SSB and SSAM SST	AA2 year ending June 2011 SSB and SSAM SST	AA2 year ending June 2012 SSB and SSAM SST	WP Proposed AA3 SSAM 2013 – 2017 (derived from 2010-11 dataset)	Authority required AA3 SSAM 2013 – 2017 (derived from 2011-12 dataset)
Circuit Availability (% of total time)	98.0	98.0	98.0	98.0	98.1
System Minutes Interrupted (meshed network) (minutes)	9.3	9.3	9.3	np	Not required
System Minutes Interrupted (radial network) (Minutes)	1.4	1.4	1.4	np	1.9
Loss of Supply Event Frequency (Number of events 0.1 to 1 System Minutes)	25	25	25	25	24
Loss of Supply Event Frequency (Number of events > 1 System Minutes)	2	2	2	2	2
Average Outage Duration (Minutes)	764	764	764	670	886

Note: np = 'not provided' by Western Power for AA3.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

Considerations of the Authority

5. Western Power appears to be implying that:

- the future performance of the network is expected to be worse than the current average service performance (that is derived from the most recent years of data);
- the most recent years of data, which generally showed improved performance, reflects some fortuitous set of circumstances above and beyond normal variability.

6. The Authority considers that these arguments are unsubstantiated by supporting analysis. Western Power has not demonstrated any direct link in its proposal between service capital expenditure and service standards performance. The Authority notes that Western Power stated in its access arrangement information that:[662]

> ...we are proposing to maintain service and compliance levels... The decision to maintain current service levels rather than further invest in improving service is based on:
>
> - a series of customer engagements and survey of customer preferences conducted in October 2010 which provided evidence that the majority of our customers are satisfied with current average service levels
> - the service standard incentive framework is considered to be sufficient to ensure investment to maintain and improve service where it is valued more than the cost of delivering. This is preferable to including additional investment for service improvements that would further increase prices.

7. The Authority notes that the largest differences between the SSTs derived from the 2010/11 and 2011/12 dataset occur for the distribution network. With this in mind, the Authority considers that the SSTs should be based on the most recent available historic data set to 2011/12, as:

- Western Power was provided with additional funds to improve the distribution networks performance over the current access arrangement – and performance did improve over that period, despite a significant underspend of the forecast capex;
- the most recent 2011/12 data will have captured ‘current’ service and performance levels that reflect expenditure in the current access arrangement, which would not have been captured completely with three years of data ending 2010/11 (as it includes data for 2008/09, in the first access arrangement period);
- Western Power will be rewarded for out-performance of the SSTs over the period of the second access arrangement; and
- Western Power is expected to undertake significant further capital expenditure through the wood poles program, which should support service performance on the distribution network.

8. The Authority considers that the SSTs for the transmission network should also be based on the most recent available historic data to 2011/12, as this is consistent with

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662 Western Power 2011, *Access Arrangement Information*, www.erawa.com.au, p. 183.

current performance. The Authority notes that in the case of Average Outage Duration this serves to increase the SST considerably.

9. In summary, the Authority therefore considers that the targets proposed by Western Power based on the 2010/11 data do not capture all of the information that is available in relation to current levels of service performance. Given Western Power's undertaking to maintain current levels of service performance (refer to paragraph 6 above), the SSAM SSTs (and SSBs) should be based on the most recent available dataset to 2011/12.

Appendix 5: Evaluating alternative options for the SSAM

1. This Appendix provides a quantitative analysis of the performance of two alternative Service Standard Adjustment Mechanism (**SSAM**) formulas, compared to the existing and proposed formulas, using the System Average Interruption Duration Index (**SAIDI**) measure for the Central Business District (**CBD**) as an example. The analysis is different to that set out in Appendix 4 of the Draft Decision, and is changed as a response to the comments made by Western Power.

Calculating SSAM incentives

2. The SSAM rewards or penalties are derived from the product of the 'service standard difference' (**SSD**) in each year, and the SSAM incentive rates. The SSD is the difference between actual performance on a measure and the target performance.

3. The SSD in the current access arrangement is calculated as follows:

   SSD2009/10 = (SSB2009/10 – SSA2009/10)

   SSD2010/11 = (SSB2010/11 – SSA2010/11) - (SSB2009/10 – SSA2009/10)

   SSD2011/12 = (SSB2011/12 – SSA2011/12) - (SSB2010/11 – SSA2010/11)

   Where:

   SSD_t is the service standard difference in year t;

   SSB_t is the service standard benchmark in year t; and

   SSA_t is the actual service performance in year t.

4. The existing SSAM SSD implied that only an incremental improvement in net performance, compared to that in the year before, was rewarded. Under this approach, performance in any year may be above the SSAM target, but a penalty still applied in that year – if the net performance is less than the year before. Conversely, performance may be below the target, but still receive a reward, provided that the net performance shortfall to the target was less than the year before. For example, the formula that applied in the current access arrangement for the second and subsequent years was:

   $SSD_t = (SST_t – SSA_t) - (SST_{t-1} – SSA_{t-1})$

5. Western Power's proposed method for AA3 on the other hand aims to institute a simple difference in each year to calculate the SSD:

   $SSD_t = (SST – SSA_t)$

6. The Authority considered two potential alternative formulas as a means to overcome the shortcomings of the above.

7. The first alternative includes an 'attenuation factor' (**AF**) in the existing formula that conditions the influence of the second term:

   $SSD_t = (SST_t – SSA_t) – \mathbf{AF * } (SST_{t-1} – SSA_{t-1})$

This is referred to as the ***factor*** approach. In what follows, the Authority considers the factor approach with a factor of 0.2.

8. The second alternative accepts the proposed approach as the formula for the SSAM – but with a proviso that the SST be updated every year to incorporate the most recent 12 months of historic data (recalls that the SST is set on the basis of the most recent available 60 months of data). This is referred to as the ***ratchet*** approach.

Value of customer reliability

9. The value of customer reliability (**VCR**) of a minute of interruption in the Perth CBD is estimated at around $70,000.[663] This is a 'transfer benefit' derived from surveys of Victorian network consumers' damage costs arising from outages, calibrated to Western Australia. This value is used in setting the SAIDI incentive rate. This value of saving one minute of SAIDI is utilised in what follows.

10. An investment to improve the performance on SAIDI by one minute each year will result in a benefit to CBD consumers of $70,000 annually. A life for the investment of 25 years may be assumed (the results that follow are not sensitive to this life, the choice of measure, or to the value of a SAIDI minute).

11. As a base case, the stream of VCR values is discounted to a present value through application of a real discount rate of 8 per cent – a commonly applied discount rate in cost benefit analysis.[664] This discount rate may be low. Business hurdle rates tend to be higher, often around 12 per cent or more in real terms. Furthermore, businesses often demonstrate discount rates related to non-core business activities – such as investments in energy efficiency – as high as 50 per cent or more.[665] The results are sensitive to this discount rate. That said, the present value (**PV**) to a user of the VCR at 8 per cent over 25 years of a minute of SAIDI improvement is $807,000.

Efficient investment in VCR

12. Consideration of economic efficiency suggests that Western Power should invest in reliability so long as the total cost to customers is less than or equal to the benefit to customers of that investment.[666] The benefit is the VCR.

13. The costs to customers will be the value of the investment made by Western Power (which would be included in the asset base at the following reset, then remunerated through return on and of the capital investment each year), any annual operating expenditures that are included in the revenue requirement, plus the value of any

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663 Specifically, the estimated damage cost in $/MWh is applied to the average MWh lost in an outage of one minute duration to determine the value of an annual SAIDI minute.

664 See for example, Productivity Commission 2010, *Valuing the Future: the social discount rate in cost-benefit analysis*, www.pc.gov.au, p. 62.

665 See for example, Sanstad A. H. and Howarth R.B. 1994, *Consumer Rationality and Energy Efficiency*, enduse.lbl.gov, p. 2.

666 The 'marginal' investment would be that investment where the cost just equals the benefit, satisfying the efficiency criterion that investments are undertaken up to the point where the marginal cost of investment equals the marginal benefit.

annual service standard incentives (which is a 'transfer' from consumers to Western Power).[667]

14. For the modelling of the investment costs, real straight line depreciation is assumed for the return of capital, with the investment assumed to have a life of 25 years. The investment is assumed to be included in the capital base from the next arrangement period. Return on capital is provided through application of a pre-tax real WACC of 4.33 per cent, which is consistent with the post tax vanilla WACC adopted for this Final Decision.[668]

15. Operating expenditures are assumed to be included in the revenue requirement from the next access arrangement period.

16. The alternative SSAM formulas are applied to determine the relevant SSAM reward.

17. The annual sums of the return on and of capital, operating expenditures charged to customers, and the SSAM reward are brought to a present cost through the application of the 8 per cent discount rate. This allows the total present cost to customers of the investment, the operating costs and the SSAM reward to be compared to the present value of the VCR.

Relative performance of the different SSAM formulas in the case of a capital expenditure

18. The relative performance of the different approaches in delivering incentives for Western Power to make capital investments in service performance improvement is set out in the following table.

    - Table 213 reports results for the case where Western Power undertakes an investment with a present cost of 50 per cent of the present value of the VCR (not including the SSAM reward);

19. It may be seen by comparing across the table that:

    - row 6 – the current access arrangement formula tends to under-reward Western Power significantly, for all but very low cost service performance improvements;
    - row 11 – the proposed simple formula provides an additional incentive, over and above normal returns, for Western Power to undertake investments across all years of the AA period;[669]

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667 This assumes that the 'cost', as given by the remuneration to Western Power through the return on and of capital plus any service standard incentives, passes the New Facilities Investment Test (**NFIT**). For this to be the case, the 'cost' must be less than the present value of the value of customer reliability that is delivered by the investment.

668 A pre-tax WACC is adopted here to simplify the modelling.

669 The additional incentive decreases progressively as the present value of the investment approaches that of the VCR.

- row 12 – the proposed simple formula provides Western Power with a proportion of the 'surplus' VCR benefits;[670]
  - Western Power's share of the 'surplus' VCR benefits is less than the share accruing to customers for lower cost investments, irrespective of the year of the investment;[671]
- row 17 as compared to row 11 – the factor formula attenuates the reward to Western Power significantly;
- rows 18 and 19 as compared to rows 12 and 13 – the factor formula delivers a significantly smaller share of the 'surplus' VCR to any investment to Western Power, as opposed to the share for customers;
- rows 22, 23 and 24 – the ratchet formula further reduces the reward to Western Power.

20. The results are sensitive to the discount rate applied. As the discount rate rises, the relative difference between the factor formula and Western Power's proposed formula increases. As the discount rate rises, the factor formula tends to reduce further Western Power's share of the 'surplus' VCR.

Relative performance of the different SSAM formulas in the case of operating expenditure

21. The relative performance of the different approaches in delivering incentives for Western Power to improve service standards performance by increasing operating expenditure is set out in the following table.

- Table 214 reports results for the case where Western Power increases the present value of operating expenditure by 50 per cent of the present value of the VCR (not including the SSAM reward).

22. It may be seen by comparing across the table, similar to the results in Table 213 that:

- row 6 – the current access arrangement formula tends to under-reward Western Power significantly for projects initiated in the early years of an access arrangement;
- row 11 – the proposed simple formula provides an additional incentive, over and above normal returns, for Western Power to undertake investments across all years of the AA period;[672]
- row 12 – the proposed simple formula provides Western Power with a proportion of the 'surplus' VCR benefits;
  - Western Power's share of the 'surplus' VCR benefits is higher than the share accruing to customers for lower cost investments in this case;[673]
- row 17 as compared to row 11 – the factor formula attenuates the reward to Western Power;

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670 'Surplus' VCR benefits means the excess of the present value of the VCR benefits over the investment and operating costs of Western Power (but excluding the incentive payments).

671 These shares increase progressively as the cost of the investment approaches the VCR.

672 The additional incentive decreases progressively as the present value of the investment approaches that of the VCR.

673 These shares increase progressively as the cost of the investment approaches the VCR.

- rows 18 and 19 as compared to rows 12 and 13 – the factor formula delivers a smaller share of the ‘surplus’ VCR to any investment to Western Power, as opposed to customers;
- rows 22, 23 and 24 – the ratchet formula further reduces the reward to Western Power, to the extent that it discourages investments that remain cost effective.

23. The results are sensitive to the discount rate applied. As the discount rate rises, the relative difference between the factor formula and Western Power’s proposed formula increases. As the discount rate rises, the factor formula tends to reduce further Western Power’s share of the ‘surplus’ VCR.

Conclusion

24. The difference between the outcomes of the ‘factor’ formula and Western Power’s proposed formula depends on the size of the factor. As the factor declines, it approaches the ‘zero’ factor that is implicit in Western Power’s proposed formula. The Authority considers that, on balance, Western Power’s proposed formula is acceptable.

25. The Authority acknowledges that its analysis does not take into account all of the risks that Western Power needs to consider when undertaking a project to improve service standards. These include that the project may not perform as expected in terms of delivering service standards, or that rewards may be delayed due to natural variation in year to year performance.

26. With this in mind, the Authority considers that Western Power’s proposed formula provides reasonable incentives for Western Power to undertake projects to improve services, while retaining an acceptable proportion of the benefits for customers.

Table 213 SSAM mechanism relative performance – capital investment at 50 per cent of the present value of the VCR

Row no.	Item	Present value of investment undertaken in year of access arrangement				
		Year 1	Year 2	Year 3	Year 4	Year 5
1	**PV of VCR**	$807,013	$807,013	$807,013	$807,013	$807,013
2	**PV of Western Power investment**	$403,507	$403,507	$403,507	$403,507	$403,507
3	'Surplus value' : difference in PV of VCR compared to WP investment	$403,507	$403,507	$403,507	$403,507	$403,507
4	**Current formula result**					
5	PV of customer payments if project started in year	$288,626	$316,406	$347,232	$381,413	$419,289
6	WP 'extraordinary' return	-$114,881	-$87,101	-$56,274	-$22,093	$15,783
7	WP's share of 'surplus' value	-28%	-22%	-14%	-5%	4%
8	Customer's share of 'surplus' value	128%	122%	114%	105%	96%
9	**Western Power 'simple' formula result**					
10	PV of customer payments if project started in year	$520,474	$530,886	$545,680	$565,492	$591,029
11	WP 'extraordinary' return	$116,968	$127,379	$142,174	$161,986	$187,523
12	WP's share of 'surplus' value	29%	32%	35%	40%	46%
13	Customer's share of 'surplus' value	71%	68%	65%	60%	54%

Row no.	Item	Year 1	Year 2	Year 3	Year 4	Year 5
14	**Factor formula result**					
15	*Year 'factor'*	*0.20*	*0.20*	*0.20*	*0.20*	*0.20*
16	PV of customer payments if project started in year	$464,576	$477,700	$494,877	$516,674	$543,718
17	WP 'extraordinary' return	$61,070	$74,193	$91,370	$113,167	$140,212
18	WP's share of 'surplus' value	15%	18%	23%	28%	35%
19	Customer's share of 'surplus' value	85%	82%	77%	72%	65%
20	**Ratchet' formula result**					
21	PV of customer payments if project started in year	$409,003	$426,493	$445,383	$465,783	$487,815
22	WP 'extraordinary' return	$5,497	$22,987	$41,876	$62,276	$84,309
23	WP's share of 'surplus' value	1%	6%	10%	15%	21%
24	Customer's share of 'surplus' value	99%	94%	90%	85%	79%

Source: Authority estimates

Table 214 SSAM mechanism relative performance – operating expenditure at 50 per cent of the present value of the VCR

Row no.	Item	Present value of expenditure undertaken in year of access arrangement				
		Year 1	Year 2	Year 3	Year 4	Year 5
1	**PV of VCR**	$807,013	$807,013	$807,013	$807,013	$807,013
2	**PV of Western Power expenditure**	$403,507	$403,507	$392,026	$385,588	$378,635
3	'Surplus value' : difference in PV of VCR compared to WP investment	$403,507	$403,507	$414,987	$421,425	$428,378
4	**Current formula result**					
5	PV of customer payments if project started in year	$322,582	$358,599	$393,120	$430,627	$472,440
6	WP 'extraordinary' return	-$80,924	-$44,908	$1,094	$45,039	$93,805
7	WP's share of 'surplus' value	-20%	-11%	0%	11%	22%
8	Customer's share of 'surplus' value	120%	111%	100%	89%	78%
9	**Western Power 'simple' formula result**					
10	PV of customer payments if project started in year	$554,431	$573,079	$591,568	$614,705	$644,180
11	WP 'extraordinary' return	$150,924	$169,572	$199,542	$229,117	$265,545
12	WP's share of 'surplus' value	37%	42%	48%	54%	62%
13	Customer's share of 'surplus' value	63%	58%	52%	46%	38%

Row no.	Item	Year 1	Year 2	Year 3	Year 4	Year 5
14	**Factor formula result**					
15	*Year 'factor'*	*0.20*	*0.20*	*0.20*	*0.20*	*0.20*
16	PV of customer payments if project started in year	$498,533	$519,892	$540,765	$565,887	$596,869
17	WP 'extraordinary' return	$95,026	$116,386	$148,739	$180,299	$218,234
18	WP's share of 'surplus' value	24%	29%	36%	43%	51%
19	Customer's share of 'surplus' value	76%	71%	64%	57%	49%
20	**Ratchet' formula result**					
21	PV of customer payments if project started in year	$442,960	$468,686	$491,271	$514,996	$540,966
22	WP 'extraordinary' return	$39,453	$65,179	$99,245	$129,408	$162,331
23	WP's share of 'surplus' value	10%	16%	24%	31%	38%
24	Customer's share of 'surplus' value	90%	84%	76%	69%	62%

Source: Authority estimates

Appendix 6: The Authority's Estimates of Equity Beta: Comparison of Pre- and Post- Global Financial Crisis Samples

The Authority calculated test statistics to determine if there was a statistical difference at the five percent level[674] between the beta estimates observed pre-Global Financial Crisis (GFC) and those estimated post-GFC.

The pre-GFC period was defined as the period from September 2003 to the end of August 2008, in order to be consistent with Henry's analysis for the AER in 2009. The post-GFC period was defined as the period from September 2008 to April 2012.

Pre-GFC sample standard errors were used in the test statistics in order to be consistent with those used by Henry.

Of the nine companies in Henry's initial analysis, only six remained by 13 April 2012. For this reason analysis was carried out on only six of the nine original companies. Of the 56 beta estimates in the Authority's original study, only six of these were statistically different post-GFC to pre-GFC; that is, had an absolute value of the test statistic greater than 1.96. Only the tables containing statistically different estimates pre and post GFC are shown here. Table 215 demonstrates that four of these were individual Australian company estimates, being: the estimate for SKI using the OLS method on monthly sampling; the estimate for ENV using both the OLS and LAD methods on weekly sampling; and the estimate for SPN using the LAD methods on weekly sampling (which only marginally rejected the hypothesis that the beta estimates were the same pre- and post-GFC).

Table 215 Test Statistic: Difference between Beta Estimates Pre and Post Global Financial Crisis - Australian Company De-Levered/Relevered estimates of β

	APA	DUE	ENV	HDF	SKI	SPN
Monthly Sampling						
OLS	-0.5566	-0.0318	-1.3915	0.9004	2.3050	0.8505
LAD	-0.2304	0.0651	0.2062	0.1702	1.4010	-1.2627
Weekly Sampling						
OLS	1.5202	1.5832	-2.2404	0.3939	-0.5066	0.1816
LAD	0.5312	1.0608	-5.4805	-0.6922	0.9476	-1.9717

The two remaining statistically different estimates were the LAD result for value weighted portfolio 4 on monthly sampling and the LAD result for equal weighted portfolio 1 on weekly sampling, as presented in Table 216 below.

674 A value of 1.96.

Table 216 Test Statistic: Difference between Beta Estimates Pre and Post Global Financial Crisis - Australian Portfolios

	P1	P2	P3	P4
	ENV, APA,	ENV, APA, DUE,	ENV, APA, DUE, HDF,	ENV, APA, DUE, HDF, SPN, SKI
Monthly Sampling				
Equal Weight, OLS	-1.1447	-0.9045	-0.3103	0.4036
Equal Weight, LAD	0.2945	0.3645	0.2721	0.6570
Value Weight, OLS	-0.9622	-0.8125	-0.5305	0.4914
Value Weight, LAD	0.0063	0.1204	0.7229	2.4212
Weekly Sampling				
Equal Weight, OLS	-0.1754	0.4408	0.6054	0.8991
Equal Weight, LAD	-2.1723	-1.6698	-0.9267	1.6628
Value Weight, OLS	0.5345	0.9692	1.0369	1.0808
Value Weight, LAD	-1.0022	0.4192	1.5612	1.4496

The majority of these tests indicate that the two sample periods do not yield statistically different beta estimates. However, it is noted that the post-GFC period results could be biased downward from the true value of beta if the securities have been thinly traded (see Appendix 8).

Appendix 7: The Authority's Estimates of Equity Beta: Portfolio Beta Estimates

The mean of the weekly equal weighted OLS sample estimates ($\hat{\beta}$) of 0.4929 is slightly greater than the median of 0.4823. In contrast, the mean of the LAD estimates ($\tilde{\beta}$) of 0.5009 is slightly less than the median of 0.5025.

Table 217 Equal Weighted Portfolio Estimates of β: Weekly Sampling - 2002.01 - 2012.04

	P1'	P1	P2	P3	P4
	04 Jan 2002 ENV, APA	05 Sep 2003 ENV, APA,	20 Aug 2004 ENV, APA, DUE,	17 Dec 2004 ENV, APA, DUE, HDF,	23 Dec 2005 ENV, APA, DUE, HDF, SPN, SKI
$\bar{G}$	0.6421	0.6574	0.6976	0.6253	0.6048
ω	0.8948	0.8566	0.7560	0.9367	0.9881
$\hat{\beta}$	0.4820	0.4823	0.4080	0.5680	0.5242
s.e	0.0369	0.0385	0.0331	0.0461	0.0460
$\hat{\beta}_u$	0.5543	0.5578	0.4728	0.6582	0.6144
$\hat{\beta}_l$	0.4097	0.4068	0.3432	0.4777	0.4339
$\tilde{\beta}$	0.4952	0.5025	0.4266	0.5343	0.5460
s.e	0.0327	0.0266	0.0313	0.0292	0.0347
$\tilde{\beta}_u$	0.5593	0.5547	0.4880	0.5916	0.6140
$\tilde{\beta}_l$	0.4312	0.4503	0.3652	0.4770	0.4781
N	540	450	400	383	330

Below, the mean of the value weighted portfolio OLS estimates of beta using weekly sample data is 0.4767, which is slightly lower than the median of 0.4932. Conversely, mean of using the LAD estimates is 0.4918, which is slightly higher than the median of 0.4757.

Table 218 Value Weighted Portfolio Estimates of β: Weekly Sampling: 2002.01 - 2012.04

	P1'	P1	P2	P3	P4
	04 Jan 2002 ENV, APA	05 Sep 2003 ENV, APA,	20 Aug 2004 ENV, APA, DUE,	17 Dec 2004 ENV, APA, DUE, HDF,	23 Dec 2005 ENV, APA, DUE, HDF, SPN, SKI
$\bar{G}$	0.6219	0.6400	0.6914	0.6562	0.6192
ω	0.9452	0.9000	0.7714	0.8596	0.9519
$\hat{\beta}$	0.5151	0.5114	0.4170	0.4932	0.4466
s.e	0.0395	0.0413	0.0347	0.0394	0.0420
$\hat{\beta}_u$	0.5925	0.5924	0.4849	0.5703	0.5290
$\hat{\beta}_l$	0.4376	0.4305	0.3490	0.4161	0.3642
$\tilde{\beta}$	0.5541	0.5547	0.4140	0.4605	0.4757
s.e	0.0408	0.0062	0.0315	0.0307	0.0368
$\tilde{\beta}_u$	0.6340	0.5669	0.4757	0.5206	0.5479
$\tilde{\beta}_l$	0.4741	0.5425	0.3523	0.4004	0.4035
N	540	450	400	383	330

Appendix 8: The Authority's Estimates of Equity Beta: Thin Trading Tests

Henry found little evidence of thin trading, both across individual companies and portfolios, between January 2001 and September 2008. The Authority used Dimson's betas to establish whether securities were thinly traded in the post-GFC period (that is September 2008 to April 2012). Dimson's betas were estimated for both the individual companies and portfolios as outlined in the equation below.

$$r_{i,t} = \alpha_i + \beta_{i-1} r_{m,t-1} + \beta_i r_{m,t} + \beta_i r_{m,t+1} + \varepsilon_{i,t}$$

Where $r_{i,t}$ is a company or portfolio return and $_i r_{m,t}$ is the market return.

The estimates are then summed to produce a Dimson beta estimate:

$$\tilde{\beta}_i^D = \beta_{i-1} + \beta_i + \beta_{i+1}$$

The results for the thin trading tests conducted by the Authority are presented in Table 219. These results were calculated using the standard errors of the OLS beta estimate and the test statistic outlined below.

$$t = \frac{\hat{\beta}_i - \tilde{\beta}_i^D}{SE(\hat{\beta}_i)}$$

This method was selected to maximise the chance of rejecting the null hypothesis, as outlined by Henry[675].

Only in the case of APA and ENV did the Authority find statistically significant evidence against the null hypothesis that $\beta_i^{OLS} = \beta_i^D$ in the monthly estimates. However, even in these cases, the evidence of thin trading is weak. Only β_{i-1} is statistically different from zero for APA[676], while neither β_{i-1} or β_{i+1} for ENV are statistically different from zero.

[675] Henry, O (2009) "Estimation Beta", *Advice Submitted to the Australian Competition and Consumer Commission*, p. 18.

[676] That is, -0.2695 divided by its standard error of 0.1324 is greater than 1.96.

Table 219 Australian Company Dimson Betas: Sampled Monthly: 2008.09 - 2012.04

	APA	DUE	ENV	HDF	SKI	SPN
β_{i-1}	-0.2695	0.3579	0.5637	1.1250	0.3175	0.1633
s.e	0.1324	0.2473	0.3026	0.5440	0.1694	0.1815
β_i	0.8055	0.5267	0.4992	-0.0415	0.0082	0.1106
s.e	0.1454	0.2715	0.3322	0.5973	0.1860	0.1993
β_{i+1}	-0.2664	-0.5368	0.2752	-0.6281	-0.1462	-0.4237
s.e	0.1548	0.2892	0.3538	0.6361	0.1981	0.2123
β_i^D	0.2696	0.3478	1.3381	0.4554	0.1795	-0.1498
β_i^{OLS}	0.7546	0.6378	0.7960	0.2625	0.1837	0.1843
s.e	0.1373	0.2331	0.2764	0.5042	0.1620	0.1760
$\beta_i^{OLS} = \beta_i^D$	3.5328	1.2441	-1.9617	-0.3826	0.0261	1.8984
N	43	43	43	43	43	43

The tests based on weekly data show no evidence against the null hypothesis that $\beta_i^{OLS} = \beta_i^D$ and therefore no evidence of thin trading.

Table 220 Australian Company Dimson Betas: Sampled Weekly: 2008.09 - 2012.04

	APA	DUE	ENV	HDF	SKI	SPN
β_{i-1}	0.0237	0.2243	0.1201	0.2491	0.0749	0.0057
s.e	0.0731	0.1020	0.1026	0.1671	0.0834	0.0790
β_i	0.5331	0.4667	0.6332	0.8548	0.4300	0.2668
s.e	0.0737	0.1029	0.1035	0.1686	0.0842	0.0797
β_{i+1}	-0.0817	-0.1242	0.0418	0.0251	-0.0805	-0.0772
s.e	0.0735	0.1027	0.1032	0.1681	0.0840	0.0795
β_i^D	0.4751	0.5667	0.7951	1.1290	0.4244	0.1953
β_i^{OLS}	0.5353	0.4516	0.6160	0.8199	0.4118	0.2795
s.e	0.0724	0.1025	0.1017	0.1661	0.0838	0.0783
$\beta_i^{OLS} = \beta_i^D$	0.8325	-1.1220	-1.7625	-1.8610	-0.1511	1.0749
N	189	189	189	189	189	189

For post-GFC equal weighted portfolios, no evidence of thin trading was found using monthly frequency sampling results or weekly frequency sampling results, as demonstrated by the low absolute values of the test statistics for the null hypothesis that $\beta_i^{OLS} = \beta_i^D$.

Table 221 Equal Weighted Portfolio Dimson Betas: Monthly Sampling: 2008.09 - 2012.04

	P1	P2	P3	P4
	ENV, APA	ENV, APA, DUE,	ENV, APA, DUE, HDF,	ENV, APA, DUE, HDF, SPN, SKI
β_{i-1}	0.1471	0.2174	0.4443	0.3763
s.e	0.1568	0.1361	0.1654	0.1351
β_i	0.6524	0.6105	0.4475	0.3181
s.e	0.1722	0.1494	0.1816	0.1484
β_{i+1}	0.0044	-0.1760	-0.2890	-0.2877
s.e	0.1834	0.1591	0.1934	0.1580
β_i^D	0.8039	0.6518	0.6027	0.4068
β_i^{OLS}	0.6820	0.5688	0.5734	0.4692
s.e	0.1399	0.1274	0.1619	0.1363
$\beta_i^{OLS} = \beta_i^D$	-0.2045	0.6092	0.0616	0.4626
N	43	43	43	43

It is noted that all six companies (being ENV, APA, DUE, HDF, SPN and SKI) were in existence over the whole sampling period and so each portfolio simply adds companies based on the date of their inception. For example, DUE commenced after ENV and APA. This is reflected by adding DUE to the companies in portfolio 1 to create portfolio 2. HDF is then added to create portfolio 3 and so forth. As a result of this P1' would give identical results to P1 as the only difference between these portfolios is the start date. The results below are all based on a sample beginning after September 2008.

Table 222 Equal Weighted Portfolio Dimson Betas: Weekly Sampling: 2008.09 -2012.04

	P1	P2	P3	P4
	ENV, APA	ENV, APA, DUE,	ENV, APA, DUE, HDF,	ENV, APA, DUE, HDF, SPN, SKI
β_{i-1}	0.0719	0.1227	0.1543	0.1163
s.e	0.0633	0.0595	0.0696	0.0612
β_i	0.5831	0.5443	0.6219	0.5307
s.e	0.0638	0.0601	0.0702	0.0617
β_{i+1}	-0.0200	-0.0547	-0.0348	-0.0495
s.e	0.0637	0.0599	0.0700	0.0615
β_i^D	0.6351	0.6123	0.7415	0.5976
β_i^{OLS}	0.5056	0.4166	0.5669	0.5184
s.e	0.0627	0.0596	0.0698	0.0612
$\beta_i^{OLS} = \beta_i^D$	-0.9481	-1.3077	-1.9453	-1.2838
N	189	189	189	189

Post-GFC value weighted portfolios for both weekly and monthly sampling also showed no evidence of thin trading based on the same test statistic.

Table 223 Value Weighted Portfolio Dimson Betas: Monthly Sampling: 2008.09 -2012.04

	P1	P2	P3	P4
	ENV, APA,	ENV, APA, DUE,	ENV, APA, DUE, HDF,	ENV, APA, DUE, HDF, SPN, SKI
β_{i-1}	0.0176	0.1367	0.2583	0.2378
s.e	0.1264	0.1311	0.1316	0.1131
β_i	0.7000	0.6383	0.5541	0.3364
s.e	0.1388	0.1439	0.1444	0.1242
β_{i+1}	-0.0798	-0.2537	-0.3030	-0.3150
s.e	0.1479	0.1533	0.1538	0.1323
β_i^D	0.6378	0.5213	0.5094	0.2592
β_i^{OLS}	0.0326	0.0351	0.0353	0.4299
s.e	0.7178	0.5799	0.5831	0.1172
$\beta_i^{OLS} = \beta_i^D$	0.1155	0.1250	0.1293	1.5821
N	43	43	43	43

Table 224 Value Weighted Portfolio Dimson Betas: Weekly Sampling: 2008.09 - 2012.04

	P1	P2	P3	P4
	ENV, APA	ENV, APA, DUE,	ENV, APA, DUE, HDF,	ENV, APA, DUE, HDF, SPN, SKI
β_{i-1}	0.0570	0.1182	0.1347	0.0873
s.e	0.0598	0.0597	0.0613	0.0567
β_i	0.5676	0.5292	0.5693	0.4585
s.e	0.0603	0.0603	0.0618	0.0572
β_{i+1}	-0.0391	-0.0718	-0.0603	-0.0691
s.e	0.0602	0.0601	0.0617	0.0571
β_i^D	0.5854	0.5757	0.6437	0.4767
β_i^{OLS}	0.5252	0.4197	0.4911	0.4381
s.e	0.0593	0.0598	0.0615	0.0566
$\beta_i^{OLS} = \beta_i^D$	-0.3762	-0.9130	-1.3967	-0.4198
N	189	189	189	189

The lack of robust evidence of thin trading across individual companies and portfolios at both monthly and weekly sampling frequencies do not support the possibility that beta estimations post-GFC are biased downward.

Appendix 9: The Appropriate Averaging Period: Diebold-Mariano Tests of Forecasting Efficiency

Introduction

The daily observed yields on Commonwealth Government Securities (**CGS**) for both 5-year and 10-year terms have significantly decreased since 2011. It is argued that lower observed yields on the CGS confirm the "flight to quality" from equities into bonds in Australia. Daily observed yields on the CGS have been used as a proxy for the nominal risk free rate of return in regulatory decisions by Australian regulators. In turn, the risk free rate is used in the estimate of the cost of capital for an access arrangement. As the daily observed yields on CGS have decreased since 2011, so too has the cost of capital (including the cost of equity and the cost of debt).

In response to a decreased yield on CGS, regulated businesses have requested regulators (including the Authority), to re-consider the effect of setting the WACC for the next five years based on the average values of the risk-free rate and the debt risk premium for a recent 20 trading day period. Regulated businesses are of the view that a longer-term average for the risk free rate may be more appropriate.

Like other Australian economic regulators, the Authority currently adopts an averaging period of 20 trading days in the month prior to the month in which the decision is made. The AER adopted an averaging period of 40 trading days in its recent final decision released on 30 April 2012[677] while the United Kingdom regulators adopt a longer-term averaging period of 5 to ten years. Regulatory periods in both jurisdictions (Australia and the UK) typically span for a period of five years.

An issue of central importance for the Authority is achieving a reasonable forecast of the risk free rate into the future for the five year duration of the regulatory period. This is because the risk free rate is both an input into the cost of equity as well as debt. As such, the estimate of the risk free rate will have a significant effect on the estimates of the WACC for Western Power's Network Access Arrangement. Therefore, the Authority seeks to establish which averaging period most accurately predicts the average risk free rate when the regulatory period of five years is applied.

The Approach

The Diebold-Mariano (**DM**) test compares the errors of two forecasting methods to determine if one method is statistically more efficient than the other method. The DM test compares the 'losses' of the two forecasts to determine the forecast that is statistically better than the other forecast. Under the DM test, a greater loss tends to indicate that a less efficient forecast method is in use. This relationship is illustrated by the following formula:

[677] The Australian Energy Regulator, 2012, Final Decision on *Powerlink Transmission Determination 2012-13 to 2016-17,* 30 April 2012.

$$\begin{aligned}\varepsilon^1_{t+h|t} &= y_{t+h} - y^1_{t+h|t} \\ \varepsilon^2_{t+h|t} &= y_{t+h} - y^2_{t+h|t}\end{aligned} \qquad (1)$$

In the context of the averaging period, $\varepsilon^1_{t+h|t}$ are the differences (or the errors) between the 10-year CGS average bond yields for the regulatory period, y_{t+h} and the 10-year CGS average bond yields for the averaging period of twenty days, $y^1_{t+h|t}$.

For example, if today is 9 July 2012 and an average of bond yields over the last twenty days (including today) is 3.5 per cent, this would be used as the forecast $y^1_{t+h|t}$ for the bond yield average for the next five years. Five years since that day, on 10 July 2017, the average of the observed yields for the regulatory period of five years is derived. If it is assumed that this figure was calculated to be 3 per cent, then the difference or error, $\varepsilon^1_{t+h|t}$ between y_{t+h} and $y^1_{t+h|t}$ would be -0.5 per cent. The forecast was over-estimated by 0.5 per cent.

Errors using other forecast methods (i.e. using different averaging periods) to create $y^2_{t+h|t}$ such as one day, five days, one year and five years are represented by $\varepsilon^2_{t+h|t}$. As some errors will be negative and some will be positive, a loss function that squares the errors is used.

$$L(\varepsilon^i_{t+h|t}) = [\varepsilon^i_{t+h|t}]^2,\ i = 1,2 \qquad (2)$$

The average difference in losses is calculated using:

$$\bar{d} = \frac{1}{T}\sum_{i=1}^{T}\left[L(\varepsilon^1_{t+h|t}) - L(\varepsilon^2_{t+h|t})\right] \qquad (3)$$

If $\bar{d}$ is positive, the loss from the twenty day average is greater than that for other averaging methods and thus indicates that it is a less efficient forecast method than the method it is being compared to. However, if $\bar{d}$ is negative, it indicates that the other forecast method's loss is greater, suggesting the twenty day average is more efficient.

To determine whether the result is statistically significant, $\bar{d}$ is converted to the DM test statistic so it can be compared to t-distributed critical values with (t-1) degrees of freedom, where t is the number of observed forecast errors in the sample. The details of the conversion are omitted here.[678]

The following hypothesis is tested:

[678] See Enders. W, 2004, *Applied Econometric Time Series,* John Wiley and Sons, New Jersey USA, p.86.

$$H_0 : E[L(\varepsilon^1_{t+h|t})] = E[L(\varepsilon^2_{t+h|t})] \tag{4}$$

$$H_1 : E[L(\varepsilon^1_{t+h|t})] \neq E[L(\varepsilon^2_{t+h|t})] \tag{5}$$

The null hypothesis (4) is that the twenty day average forecasting efficiency is equal to that of the method it is being compared to. The alternative hypothesis is that the forecasting efficiency is not equal.

A t-distributed critical value of 1.96 is used if the number of observations exceeds 120 and a five percent chance of incorrectly rejecting the null hypothesis is tolerated. A DM statistic greater than 1.96 in this situation leads to a rejection of the null hypothesis.

$$|DM| > 1.96 \tag{6}$$

Attention can then be turned to whether the DM statistic is negative or positive for an indication of which series has the highest forecasting efficiency.

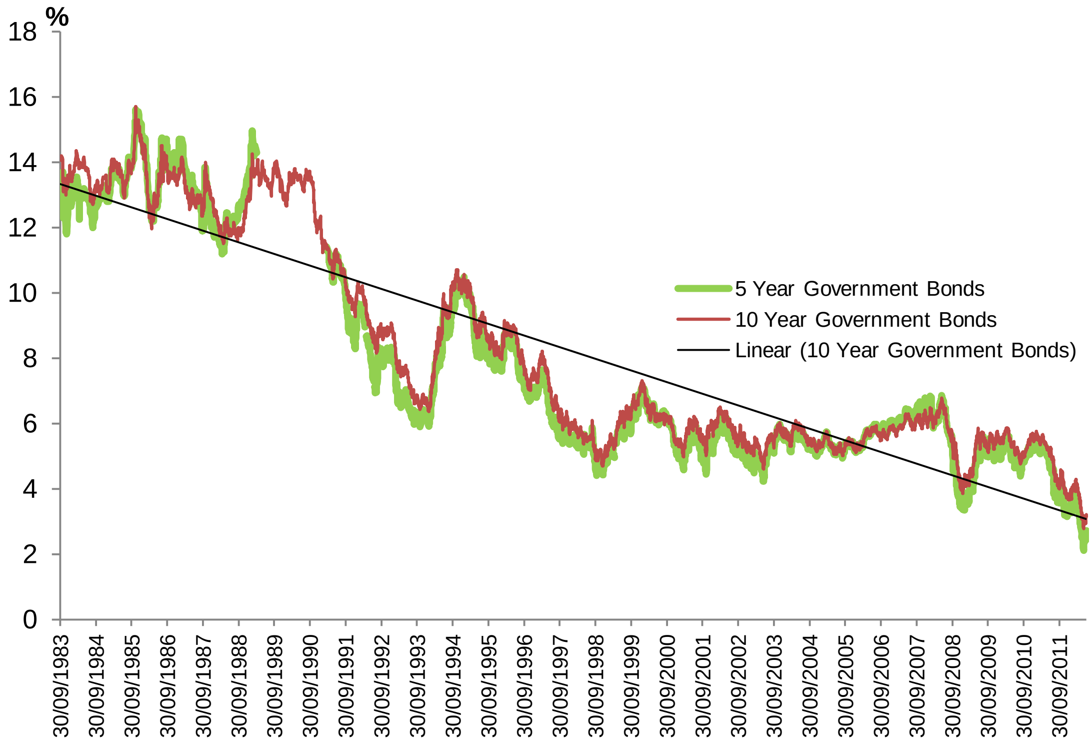
Data

Ten year Commonwealth Government Bond yield data from Bloomberg was used to carry out the tests on the different averaging periods. This series was used because the five year bond yields contained 492 missing observations, compared with only seventeen missing observations in the ten year CGS yields series. The observations cover the period from 30 September 1983 to 4 July 2012 with 7,322 daily observations of bond yields.[679]

Based on its own analysis the Authority is of the view that the ten year series is an excellent predictor of *movements* in the five year series (as opposed to the level) because the two series are both co-integrated and are also very highly correlated. This means that the two series of ten year and five year CGS bond yields are closely tied to one another and virtually always move in the same direction as presented in Figure 34. The correlation coefficient between the two series was calculated to be 0.99. Co-integration tests are discussed below.

[679] Bloomberg tickers are GACGB10 Index and GACGB5 Index for 10-year and 5-year CGS bonds respectively. These two series are the mid-yield to maturity, which is implied by the mid-point of the bid-ask prices. The sample size represents 7,322 mid-yield to maturity observations.

Figure 34 Observed Yields on 10-year CGS versus 5-year CGS, September 1983 to July 2012, Per cent



Source: Bloomberg

Engel-Granger co-integration tests were carried out using a two-step process where a regression is run first to acquire a series of errors e_t and then, secondly, the errors are tested for stationarity using the Augmented Dickey Fuller (ADF) test. The following regression, Equation 7, was run to obtain standard errors.

$$\text{5Y Yield}_t = \alpha + \beta \times (\text{10Y Yield}_t) + \varepsilon_t \tag{7}$$

Taking the expected value[680] of this equation, and assuming the five year bond yield moves one for one with the ten year bond yield on average, Equation 8:

$$\text{5Y Yield}_t = \alpha + \beta \times (\text{10Y Yield}_t) \tag{8}$$

Where α is the difference between the two over the long run, which is often interpreted as the liquidity premium, and β equals one indicating that both five year and ten year yields move one for one. On average, the error ε_t is expected to be zero and as such, they are cancelled out.

Regression (7) was run over the period 30 September 1983 to 4 July 2012 with the results outlined in Table 225. On average, the difference between the five year yields and ten year yields is around 36 basis points as indicated by the result for α. The result for β is also very close to one.

680 Probability weighted average.

Table 225 5-Year CGS Bonds versus 10-Year CGS Bonds

Regression: 5 Year Bond Yield on 10 Year Bond Yield			
Parameter	**Result**	**Standard Error**	**p value**
α	-0.367397	0.011286	< 0.0001
β	1.014398	0.001339	< 0.0001
Number of observations	6828	(492 missing)	
R-Square	0.9882		

Source: Economic Regulation Authority's analysis

This indicates that the two series move close to one for one. Both results are highly significant, that is statistically not likely to be zero, as indicated by the p value, which shows the probability of this is virtually zero.

The implication of this finding is that the five year CGS yields can be forecast by the ten year CGS yields by deducting 36 basis points from the forecasts of ten year CGS yields as implied by Equation (8).

The ADF test revolves around the concept of the 'random walk' shown in equation (9) below.

$$Y_t = Y_{t-1} + \varepsilon_t \tag{9}$$

In the context of today, this can be interpreted as '*today's t value is yesterday's (t-1) value plus a random error that we can only observe once today's value is known*'. This can also be interpreted as '*tomorrow's t value is today's (t-1) value plus a random error that we can only observe once tomorrow's value is known*' and so on. All past random errors are included in all future values of Yt. This means that the Yt series follows a path of random shocks and will not necessarily revert to any long run value. And as a result, it is more difficult or frequently impossible to predict.

Equation (9) can also be augmented to include a trend. This modification means that although the series has a trend in a particular direction; it randomly deviates from this path with each past deviation being reflected in all future values. The random walk is a 'non-stationary' process. A non-stationary process, among other things, has a mean and variance that is not constant through time.

A major implication of a process that follows a random walk process is that the best predictor of Y_t is Y_{t-1}. This is demonstrated using the expected value of equation (9) on average:

$$Y_t = Y_{t-1} \tag{10}$$

This is because, on average, the errors ε_t are a random process that is expected to average out to zero. By using Y_{t-1} as a predictor of Y_t, the errors are minimised through avoiding a situation where Y_t was predicted to increase and when it actually decreased and vice versa.

A stylised way of explaining the ADF test is testing to see if ρ in equation (11) below equals one, that is has a *unit root* and becomes the random walk in equation (9).[681]

$$Y_t = \rho Y_{t-1} + \varepsilon_t \tag{11}$$

ADF tests were carried out on the five year and ten year CGS yields data to determine whether they contained a unit root and thus followed a random walk. The outcomes are presented in Table 226.

Table 226 ADF Tests

Augmented Dickey Fuller Tests: Null Hypothesis - Series has unit root			
	5 Year Yields	**10 Year Yields**	**Regression (7) Errors**
test-statistic	-2.1356	-2.331	-5.0201
	Critical Values		
1 per cent	-3.96	-3.96	-2.58
5 per cent	-3.41	-3.41	-1.95
10 per cent	-3.12	-3.12	-1.62
Outcome	Non-Stationary	Non-Stationary	Stationary

The ADF is very sensitive to the specification of the test. For example, if the series contains a trend, the test must be specified with trend. Figure 34 strongly suggests a declining trend in each series and so the test was conducted 'with trend'. Both series did not reject the hypothesis of containing a unit root as indicated by the absolute value of their test statistics -2.1356 and -2.331 being lower than all absolute value of the critical values below. This indicates that they follow a random walk, albeit with trend.

Two or more non-stationary processes such as the five year and the ten year yields can be considered co-integrated if a linear combination of the two (such as addition or subtraction from each other) is stationary. For example, equation (7) can be rearranged as:

$$\text{5Y Yield}_t - \beta \times (\text{10Y Yield}_t) = \alpha + \varepsilon_t \tag{12}$$

The difference between the two series is α and ε_t. There is no need to test α as a constant is stationary. An ADF test need only be carried out on ε_t. The results are shown in Table 226 above.

The absolute value of the test statistic (5.0201) is greater than all absolute critical values. This means that the hypothesis of a unit root is rejected and the series is stationary. This indicates that the two series are 'tied' together in the sense that the difference between them is stationary. However, it is noted that it will not wander in a random erratic sense but tend to revert back to a long term mean.

681 In actuality, the equation is rewritten with parameter δ which equals $(\rho - 1)$. This parameters is tested to see if it is statically different from zero. A value of zero implies ρ equal to one and thus a (10) becomes (9), that is, a non-stationary random walk.

The finding that the two series are highly correlated and co-integrated indicates that the ten year yields are a good proxy for movements in the five year yields. This means that the ten year CGS yields can be used to test the forecasting efficiency of the five year CGS yields.

Figure 35 20 trading day averaging period

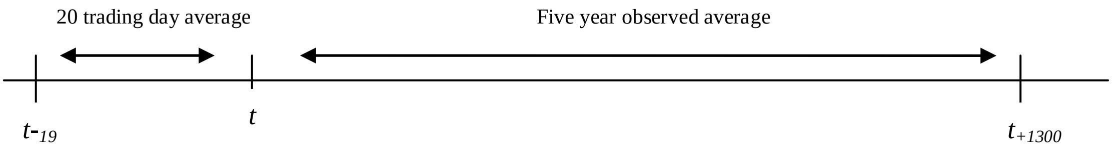
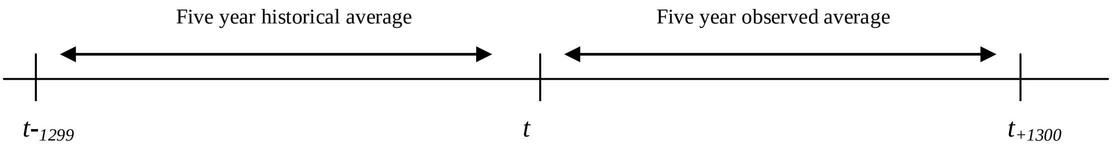


Figure 36 Five year averaging period



A number of different averaging periods were used as a test against the twenty day period including one day, five days, one year and five years. One year is assumed to be 260 trading days, which implies that five years is 1,300 days. For the twenty day average, if time t is now, nineteen trading days prior to and including t forms the twenty trading days. This is the forecast at time t for the five year average as presented in Figure 35 above. The actual five year average itself can only be observed five years (or 1,300 trading days) after t. Similarly, for the five year average forecast if time t is now 1,299 trading days prior to and including t makes the 1,300 trading days (see Figure 36).

Results

The twenty day averaging period was tested against the one day, five day, one year and five year averages using the DM statistic in equation (6) to test the hypothesis in equation (4). The DM statistic was computed using R open source statistical software and reported in Table 227.

Table 227 Forecasting Efficiency: 20 Trading Days Period versus Other Averaging Periods of 1 Day; 5 Days; 1 Year; and 5 Years

Other Averaging Period Forecasts	test - statistic
1 Day	1.2907
5 Day	1.3069
1 Year	-5.8112
5 Year	-1.9357

Only results greater than 1.96 are statistically significant with 95 per cent confidence. Negative values indicate that the twenty day average is the superior forecast method, where as positive results indicate the opposite.

The results indicate that the one day and five day forecast efficiency are not statistically different from twenty days. However, the one year period test statistic is highly significant, with the negative number indicating that twenty days has superior forecasting efficiency over one year. The five year forecast efficiency is not statistically different from the twenty day forecast with 95 per cent confidence. However, it is significant with 90 per cent confidence[682] and again the negative statistic indicates that the twenty day averaging period has superior forecasting efficiency to five years.

Conclusion

The ten year Australian Government bond yield was found to be a good predictor of movements in the corresponding five year CGS yields. Due to a large number of missing observations in the five year data, the ten year CGS yields were used to test the forecast efficiency of different averaging periods, being twenty trading days; one day; five days; one year; and five years. Augmented Dickey Fuller tests indicate that the 10-year bond yield series follows a random walk. The implication is that the latest value is the best predictor of future values. In addition, it is noted that both bond yield series also exhibit a strong downward trend, which indicates that future values will tend to be overestimated by past values. The problem is compounded when observations from further back into the past are used to forecast values further into the future. This lends further weight to the ADF test's implication that the latest value of the bond yields is the best predictor of future yields, despite the tendency of this to overestimate future yields.

The DM test was used to formally test the forecasting efficiency of different averaging periods. The results suggested that, statistically, there is no difference in forecasting efficiency between twenty, five or one day averaging period forecasts. Twenty day based forecasts were significantly superior to one year based forecasts with 95 per cent statistical confidence. They were also superior to five year based forecasts, but with only 90 per cent statistical confidence. The tests again confirm that the most recent value of Australian Government bond yields is the most efficient predictor of the future yields, being the twenty trading day average period.

[682] A t-distribution critical value at 10 per cent significance and greater than 120 degrees of freedom is 1.658, the absolute value of -1.9357 being greater thus rejecting the hypothesis of equal forecasting efficiency.

Appendix 10: Consultant Reports Commissioned by the Authority

The following consultant reports[683] were commissioned by the Authority:

- Geoff Brown and Associates, Technical Review of Western Power's Proposed Access Arrangement for 2012-2017, March 2012
- BDO, Agreed Upon Procedures Engagement-Western Power's Access Arrangement for the South West Interconnected Network, March 2012
- Geoff Brown and Associates, Technical Review of Western Power's Comments on Economic Regulation Authority's AA3 Draft Decision, September 2012

683 Reports are available from the Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

Appendix 11: Western Power Service Standard Performance Report – 2011/12

Appendix 12: Terms / Abbreviations

Term	Definition
AA1	Access Arrangement for the first period (commencing 1 July 2007)
AA2	Access Arrangement for the second period (commencing 1 March 2010)
AA3	Access Arrangement for the third period (expected to commence 1 July 2012)
AA4	Access Arrangement for the fourth period (expected to commence 1 July 2017)
ACCC	Australian Competition and Consumer Commission
Access Arrangement Information	Western Power's Access Arrangement information
Access Code	*Electricity Networks Access Code 2004*
ACG	Allen Consulting Group
ACT	Australian Competition Tribunal
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AF	Attenuation Factor
APR	Annual Planning Report
AQP	Application and Queuing Policy
ASX	Australian Stock Exchange
Authority	Economic Regulation Authority
AWOTE	Average Weekly Ordinary Time Earnings
BDO	BDO Chartered Accountants
CAIDI	Customer Average Interruption Duration Index
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CBRM	Condition Based Risk Management
CCI	Chamber of Commerce and Industry
CEG	Competition Economists Group
CGS	Commonwealth Government Securities
CPI	Consumer Price Index
Current access arrangement	Western Power's access arrangement for the second access arrangement period

Term	Definition
CWIP	Capital work in progress
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DHM	Distribution Headworks Methodology
DLVCS	Distribution Low Voltage Connection Scheme
DNS	Distribution Network Service Provider
E&Y	Ernst & Young
EGWW	Electricity, Gas, Water and Waste Services
ERA	Economic Regulation Authority
ERM	ERM Power Ltd
ESC	Essential Services Commission of Victoria
ETAC	Electricity Transfer Access Contract
ESCOSA	Essential Services Commission of South Australia
GBA	Geoff Brown & Associates
GHD	GHD Australia
GSL	Guaranteed Service Level
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
IAM	Investment Adjustment Mechanism
ICRC	Independent Competition and Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
LAD	Least Absolute Deviation
MAIFI	Momentary Average Interruption Frequency Index
MRP	Market Risk Premium
MWEP	Mid West Energy Project
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NFIT	New Facilities Investment Test
NPV	Net Present Value
NQ&RS Code	*Electricity Industry (Network Quality and Reliability of Supply) Code 2005*
POE	Probability of Exceedence

Term	Definition
Proposed revised access arrangement	Western Power's proposed revised access arrangement for the third access arrangement period
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCA	Queensland Competition Authority
RAB	Regulated asset base
RBA	Reserve Bank of Australia
RPIP	Rural Power Improvement Program
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEO	Seasoned Equity Offerings
SFG	Strategic Finance Group
SKM	Sinclair Knight Mertz
SSAM	Service Standards Adjustment Mechanism
SSB	Service Standard Benchmarks
SSD	Service Standard Difference
SST	Service Standard Target
SUPP	State Underground Power Project
SWIN	South West Interconnected Network
TAB	Taxation asset base
TEC	Tariff Equalisation Contributions
the Act	*Electricity Industry Act 2004*
TUOS	Transmission Use of System
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WAGN	Western Australia Gas Networks
WALGA	Western Australian Local Government Association
WAMEU	Western Australian Major Energy Users
WATC	Western Australian Treasury Corporation
WEM	Wholesale Electricity Market
WPI	Wage Price Index

Appendix 13: Confidential Annexure

Not published.