Economic Regulation Authority
Western Australia

Supplementary Report on Western Power's Revised Proposed Access Arrangement Expenditures and Valuation

September 2006

Wilson Cook & Co
Engineering and Management Consultants
Advisers and Valuers

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Reply to: Auckland Office
Our ref: 0610
Email: info@wilsoncook.co.nz

27th September, 2006

Mr K. P. Kolf
General Manager
Economic Regulation Authority
Level 6, Governor Stirling Tower
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PERTH WA 6000

Dear Mr Kolf,

Supplementary Report on Western Power's Revised Proposed Access Arrangement Expenditures and Valuation

In response to your instructions, we present our supplementary report on the capital, operating and maintenance expenditures and network fixed asset valuation in Western Power's revised proposed access arrangement for its south-west interconnected network, submitted on 19 May 2006.

Amended amounts are recommended to the Authority for each expenditure stream as summarised in section 8.1 of the report and various points for your attention are noted in section 8.2. However, in all other respects, the findings and recommendations in our Final Report to the Authority of December 2005 remain unchanged and this report is supplementary to, and is to be read in conjunction with, that report. (For the avoidance of doubt, we confirm that our email of 17 January 2006, which the Authority referred to in its draft decision, is now superseded.)

As noted previously, Western Power is in a transitional phase, restructuring itself and introducing new systems to improve service levels and reduce costs. The expenditures that we have recommended take account of that situation whilst still meeting the Code's overall requirement that expenditures do not exceed the amounts that would be made by a service provider efficiently minimising costs.

Yours faithfully,

Wilson Cook & Co Limited

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Economic Regulation Authority:

Supplementary Report on Western Power's Revised Proposed Access Arrangement Expenditures and Valuation

Prepared for the Economic Regulation Authority

By Wilson Cook & Co Limited

Enquiries to Mr J W Wilson

Our reference 0610

September 2006

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Disclosure

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1 Introduction

1.1 Background and Engagement

In August 2005, the Economic Regulation Authority of Western Australia (the Authority) [1] appointed Wilson Cook & Co Limited, Engineering and Management Consultants, Advisers and Valuers, of Auckland to provide the Authority with an assessment of the technical merit, appropriateness of the methodologies employed, and reasonableness of the cost bases of Western Power's proposed capital base valuation and its forecasts of capital and operations and maintenance expenditure for the forthcoming three-year access arrangement period (the period). The consultant's advice was to assist the Authority in its review and approval process for the proposed access arrangement submitted by the then Networks Business Unit of Western Power Corporation that month.[2] [3] We reported to the Authority in December 2005,[4] the Authority presented its draft decision on the proposed access arrangement in March 2006 [5] and Western Power presented a revised access arrangement and a submission in response in May 2006.[6] The Authority then re-engaged us to review the revised expenditures and valuation and to report to it by 31 July 2006.

1.2 Terms of Reference

In summary, our terms of reference were to review the operating and capital expenditures of the revised proposed access arrangement, review the additional information provided by Western Power and review any changes proposed in the initial capital base. Specifically, we were to address the following matters in relation to the proposed expenditures on Western Power's covered infrastructure in the southwest interconnected system for both transmission and distribution networks.

(a) Review and comment on variations in Western Power's revised proposed access arrangement relative to the access arrangement originally proposed and the Authority's draft decision in relation to:

  (i) the reasonableness and appropriateness of, or recommend alternatives to, the components and values in operations and maintenance expenditure (opex) and capital expenditure (capex);

  (ii) relevant reports from Western Power's consultant opex and capex variations and/or tender results for the transmission and distribution businesses; and

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1 References throughout the report to 'the Authority' are to the secretariat to the Authority unless the sense requires reference to the Authority itself.

2 Access arrangement (as defined in the Code): "an arrangement for access to a covered network that has been approved by the Authority under this Code". A covered network is one in respect of which "the service provider of the network is subject to section 4.1 of the Code".

3 With effect from April 2006, Western Power was split into separate businesses, the Network Business Unit retaining the name "Western Power" (referred to throughout the report as 'Western Power'). No change arose in respect of the nature or extent of the southwest interconnected system because of this event.

4 *'Assessment of Western Power's valuation and proposed expenditures'*, Wilson Cook & Co Limited, December 2005.

5 *'Draft decision on the Western Power Networks Business Unit proposed access arrangement for the south west interconnected network submitted by Western Power Corporation'*, Economic Regulation Authority, 21 March 2006.

6 *'Revised proposed access arrangement for the south west interconnected network owned by Western Power'*, Western Power, 19 May 2006 and *'Response to the required amendments detailed in ERA's draft decision on Western Power's proposed access arrangement for the network of the south west interconnected system'*, Western Power, 19 May 2006.

(iii) any discrepancies between the proposed variations and their underlying supporting rationale.

(b) Review and analyse the additional information provided by Western Power under the Authority's request for additional information, issued on 21 June 2006.

(c) Compare [the revised proposed] opex and capex forecasts and historical averages against data for similar wires businesses elsewhere. [7]

(d) Investigate and comment on any discrepancies and make recommendations.

In relation to the valuation of network fixed assets, we were required to consider any variations to the methodology and/or quantum of the initial capital base proposed by Western Power consistent with the requirements of section 6.46 of the *Electricity networks access code, 2004* (the Code) and to identify any other specific issues that in our opinion have arisen and warrant further explanation to support any variation to the proposed valuation.

As before, we were to have regard to 'industry best practice', all applicable legislation, the Authority's draft decision, precedents relevant to regulated energy infrastructure in Australia including the objectives of the Code and the characteristics of the southwest interconnected network as defined in the *Electricity Industry Act, 2004* (the Act).

Interpretation

In interpreting the preceding paragraph, we noted that in the same part of our previous terms of reference the reference to the Code was to Section 2.1 of it. That section states the objective of the Code as being "to promote the economically efficient: (a) investment in; and (b) operation of and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks". In considering the Code in the context of the preceding paragraph, we adopted that clause as the objective, as we did on our original work. We also adopted the same interpretation of 'industry best practice' as before – see p. 11 of our Final Report. In relation to the 'applicable legislation' requirement, we did not consider it within our scope or the time available to search the statutes ourselves but relied instead on guidance from the Authority as to the acts and regulations that impinged on the matters reviewed. The impacts were found to arise principally in relation to technical and safety regulation.

1.3 Scope of Review

It was agreed with the Authority that amendments to the proposed expenditures would not be limited to those caused by outside events that had occurred after the submission of the original proposed access arrangement but that we would consider any reasonable revisions that Western Power proposed, for example on the basis of better information now available.

1.4 Methodology and Approach

Unless noted otherwise in this report, the methodology and approach followed in this supplementary assessment were those followed in our assessment of Western Power's original proposal and described in our Final Report of December 2005. Likewise, the same considerations formed the basis of our opinion and the same items were excluded from the scope of our assessment.

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7 Taken literally, the terms of reference required the variations to be compared with data from other companies but the intent clearly was that the revised expenditures as a whole should be compared.

1.5 Work Programme, Consultation and Reporting

Work on this supplementary assessment commenced in May 2006 on receipt of the revised proposed access arrangement and submission from Western Power. A request for further information was prepared and forwarded to Western Power by the Authority on 21 June 2006. Western Power's response was received on 5 July 2006 with some further information being requested and received up to 26 July.

Our team meet with Western Power on 10-12 July. The object of the meetings was to discuss the rationale for the changes in expenditure and to discuss in detail, with Western Power's staff, each of the main items. Meetings were also held with the Authority to summarise our preliminary findings and matters related to process.

Following receipt and analysis of the information, and after obtaining the clarifications we required of certain points, we prepared our report and submitted it to the Authority on 31 July as a draft for review and confirmation that it addressed our terms of reference. This draft was sent to Western Power for confirmation that it did not contain factual errors, misinterpretations of the material received from Western Power or information that is confidential to Western Power. The final report was tabled with alterations on 27 September for the Authority's use.

The work was carried out for and on behalf of Wilson Cook & Co Limited by a team comprising Mr Jeffrey Wilson (team leader), Mr Derek Walker and Mr Steven Cooke.

A list of personnel met during this supplementary assessment is given in appendix A.

1.6 This Report

This report summarises the work carried out, our general observations and conclusions. It is presented in seven main sections:

Section 1	Introduction (this section)
Section 2	General Matters
Section 3	Transmission Capex
Section 4	Transmission Opex
Section 5	Distribution Capex
Section 6	Distribution Opex
Section 7	Adjustment of Initial Capital Base
Section 8	Conclusions and Recommendations.

1.7 Report to be Read in Conjunction with Final Report

This report is supplementary to, and is to be read in conjunction with, our Final Report to the Authority of December 2005. Unless varied by this report, the findings and recommendations expressed in our Final Report remain unchanged. For the avoidance of doubt, sections 1 (introduction), 2 (background and approach) and 4 (key expenditure-related considerations) in the Final Report all apply to the present supplementary assessment except where noted otherwise in the present report. The assessments in sections 3, 5, 6, 7, 8 and 9 also still form the foundation of our opinion in this supplementary assessment although the text in the present report varies them as required to take account of the new estimates. Section 10 (conclusions and recommendations) is modified by the present report.

For the avoidance of doubt, our email of 17 January 2006, which the Authority referred to in its draft decision, is now superseded.

Other than in these respects, this present report supersedes all earlier written or oral opinions or statements presented by us on the matters discussed.

1.8 Acknowledgements

The cooperation and assistance of the Authority and Western Power in the preparation of the report are gratefully acknowledged.

2 General Matters

2.1 Summary of Changes Proposed by Western Power

Revised Estimates for YE 2007 to YE 2009

In its revised documentation, Western Power identified several significant events that have occurred since the 2005 estimates were prepared, including:

- the separation of Western Power Corporation into separate businesses;
- further development of the Technical Rules (although they remain a draft);
- customer-driven generation-related and bulk supply projects that have reached a higher level of commitment;
- agreements on future wage increases;
- discussion with contractors of the resources available for capital works; and
- the availability of revised estimates of actual expenditure for YE 2006. [8]

As a result, it has revised its capex and opex for the period YE 2007 to 2009, compared to the August 2005 proposal and the levels analysed in our Final Report. Table 2.1 summarises the changes.

Table 2.1: Changes in Projections for YE 2007-2009 ($m nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Capex				
Transmission a/	171.6	215.1	130.5	25
Distribution b/	255.8	294.2	115.3	15
Opex				
Transmission c/	82.9	65.5	-52.4	(21)
Distribution d/	161.6	202.3	122.0	25

a/ Accounted for by an increase in customer-driven work of $116.7 m and metering and wholesale market costs ($15 m) and a small adjustment.
b/ Accounted for by an increase in customer-driven work of $78.9 m, an extension of the RPIP programme ($12 m), additional IT&T expenditure ($20 m) and other items.
c/ Comprised of a reduction in network support costs ($63.3 m) offset by the cost of providing miscellaneous network services ($13.1 m) and other items.
d/ Accounted for by an increase in maintenance costs ($64.9 m), IT&T expenditure ($7.9 m), network support costs (including a re-allocation from transmission) ($41.8 m) and other items.

The table shows that the proposed capex has increased by $245.8 m over the period, $130.5 m for transmission and $115.3 m for distribution. The main changes, detailed in later sections of the report, are a higher projected level of costs for customer-driven work in transmission and distribution – the latter driven mainly by Western Power's interpretation of the new draft Technical Rules – additional IT expenditure and the extension of the RPIP programme. An amount proposed in relation to the wholesale market has subsequently been withdrawn, according to our information. Another amount in relation to generation tariff

8 Revisions to the previous forecasts of demand included in the Independent Market Operator's updated *'Statement of opportunities report'* of July 2006 have not been taken into account by Western Power or us.

meters was apparently included at the direction of the governmental task force responsible for directing the restructuring of Western Power Corporation.[9]

The proposed opex has increased by $69.6 m over the period, comprised of a $52.4 m reduction for transmission and a $122.0 m increase for distribution. The reduction in transmission opex arises from a re-allocation of support costs from transmission to distribution, incorporation of the reductions we recommended in our Final Report and some other changes. The increase in distribution opex arises from this transfer, an increase in distribution maintenance costs and higher IT&T, network support and operational costs. A new item has been added for miscellaneous network services but it should be offset by revenues from the third parties who receive the services.

Revised Estimate for YE 2006

Table 2.2 summarises the changes made by Western Power in its estimates of expenditure for YE 2006. The main reasons for the changes are given in the notes to the table.

Table 2.2: Changes in Estimates for YE 2006 ($m nominal)

YE 30 June	Forecast (Aug 05) 2006	Updated Forecast 2006	Increase
Capex			
Transmission a/	191.0	201.2	10.2
Distribution b/	229.2	288.2	59.0
Opex			
Transmission c/ e/	71.2	69.6	-1.6
Distribution d/ e/	155.2	196.4	41.2

a/ Accounted for by an increase in demand-related expenditure ($6.8 m) and support costs ($4.2 m) and by other items.
b/ Increase in customer-driven and vested asset categories accounts for $56.7 m of this increase.
c/ Includes a $13.2 m reduction in network support costs that have been re-allocated to distribution, offset by a $7.2 m increase in maintenance and by other items.
d/ Includes an increase in network support costs of $20.3 m, an increase of $13.2 m in maintenance and reliability expenditure and other items.
e/ The updated forecast 2006 figures cited are taken from the AAI Appendix 6 pp. 78 and 134. There are minor discrepancies between them and the figures cited on p. 7 (ibid) and on p. 9 of the AAI.

Western Power also made consequential changes in its network fixed asset valuation and provided us with a reconciliation of the changes that we discuss in section 7.

2.2 Cost of Shared Services

IT&T and network support services in Western Power are provided for both transmission and distribution and the costs are allocated to the two parts. Therefore, whilst considering the cost allocations to transmission and distribution separately, we also reviewed the proposed costs of these services as a whole.

Capex

Table 2.3 summarises the original and revised capex proposals for these services for the period and shows the original and revised estimates for YE 2006. (The table discloses a

9 This item is discussed further in section 3.2.

material movement in capex between IT&T and network support services in the two estimates for YE 2006, although the projected total of both components for that year has not changed significantly.)

Table 2.3: IT&T and Network Support Services Costs (Capex) ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Proposed (Transmission + Distribution)								
IT&T	17.8	21.1	15.6	17.8	9.3	31.6	22.5	20.4
Network Support Services	7.4	7.7	7.6	7.9	14.2	7.7	7.6	7.9
	25.2	28.8	23.2	25.7	23.5	39.3	30.1	28.3
Our Recommendation			**Final Report**				**Now**	
IT&T	17.8	21.1	15.6	17.8	9.3	27.1	20.6	17.8
Network Support Services	7.4	7.7	7.6	7.9	14.2	7.7	7.6	7.9
	25.2	28.8	23.2	25.7	23.5	34.8	28.2	25.7
Resulting Adjustment Recommended in IT&T								
Distribution						-4.5	-1.9	-2.6

Source of original data: Western Power (as amended, November 2005) and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.

Table 2.4 analyses the movements in the estimates due to the revised proposals and shows that Western Power is now planning to spend an additional $20 m or 37% on IT&T capex during the period, compared to its earlier proposal. There has been no change in the capex proposed for network support services.

Table 2.4: Movements in Capex Estimates ($ nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Proposed (Transmission + Distribution)				
IT&T	18.1	24.8	20.0	37
Network Support Services	7.7	7.7	0.0	-
	25.9	32.6	20.0	26
Our Recommendation	**Final Rpt**	**Now**		
IT&T	18.1	21.8	11.0	20
Network Support Services	7.7	7.7	0.0	-
	25.9	29.6	11.0	14

Although the combined IT&T and network support services capex accounts for only around 6% of total capex, the increase of $20 m (in IT&T) was considered material and was reviewed with Western Power. We examined the draft business cases for the IT&T work involved and noted that: they did not appear to be in a final form (the copies we received had not been signed as approved); some were between 12 and 18 months old and thus did not reflect Western Power's statement that its IT&T costs had just been reviewed; the same benefits appeared to have been ascribed to several of the systems separately; savings identified appeared in our view to be optimistic; the business cases did not appear to include all costs involved – specifically, communications costs associated with the programme to provide computers for field staff did not appear to have been included – and the cost of the training required to introduce the new systems and bring about the necessary, accompanying, cultural and behavioural changes did not appear to have been allowed for adequately. We also had doubts whether such an ambitious rollout of several new systems was practical in the time. Overall, we formed the view that the business cases did not provide strong evidence in support of the expenditures and that, on finalisation of its IT&T plans, Western Power's new management team would be unlikely to accept all the proposals described in the documents but would cut them back, prioritising expenditure on those most important in achieving operational cost savings and service improvements. [10]

In considering a reasonable level of IT&T expenditure to recommend, we noted that Western Power's submission cites on p. 35 four reasons for the proposed uplift of $20 m in IT&T expenditure. We accepted three (the addition of the 'HiREPS' project, logistics service group and related projects, and the cost of support work relating to post-reform implementation) but did not consider that sufficient justification had been provided for the fourth item (increases in project costs following a review of original cost estimates, along with re-forecasting of timing for implementation schedules, totalling $9 m). Accordingly, after considering the material available to us, we recommend that additional distribution capex be agreed to for IT&T services only up to $11 m, spread over the first two years of the period, in place of the $20 m sought. No change is required in the level of network support services expenditure proposed in our Final Report.

The resulting recommended expenditures are shown in Table 2.3 and Table 2.4, together with a comparison with the expenditure recommended in our Final Report.

Opex

Table 2.5 summarises the original and revised opex proposals for these services for the period and shows the original and revised estimates for YE 2006.

Table 2.5: IT&T and Network Support Services Costs (Opex) ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Proposed (Transmission + Distribution)								
IT&T	16.8	17.8	20.1	22.9	17.0	20.8	23.1	27.6
Network Support Services	53.4	64.6	72.9	77.8	60.5	59.4	65.3	69.0
	70.1	82.3	92.9	100.7	77.5	80.2	88.4	96.6
Our Recommendation			**Final Report**				**Now**	
IT&T	16.8	17.8	20.1	22.9	17.0	20.8	22.1	22.9
Network Support Services	53.4	55.0	56.7	58.3	60.5	59.4	56.7	53.9
	70.1	72.7	76.7	81.2	77.5	80.2	78.7	76.8
Resulting adjustment recommended now in IT&T								
Distribution						0.0	-1.0	-4.7
Allocation of recommended Network Support expenditure a/								
Transmission						13.6	13.0	12.3
Distribution						45.8	43.7	41.6
Resulting adjustment recommended now in Network Support costs								
Transmission						0.0	-2.2	-3.2
Distribution						0.0	-6.4	-11.9

Source of original data: Western Power (as amended, November 2005) and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.
a/ Allocated in same ratio as that used in Western Power's revised proposal.

Taken together, Western Power is planning to increase its opex on these two categories from its estimated $77.5 m in YE 2006 to $80.2 m, $88.4 m and then $96.6 m in YE 2007, YE

10 New management appointments have been made since some or all of the business cases were prepared.

2008 and YE 2009 respectively. By comparison, its expenditures on these two categories combined in the years YE 2003 to YE 2005 were $52.2 m, $56.4 m and $60.7 m respectively.

Also by comparison, we noted that ETSA Utilities' projected annual corporate costs for YE 2006 were around $31 m.[11] ETSA Utilities handles only distribution and sub-transmission up to 66 kV. It serves around 760,000 consumers. It owns and maintains around 77,600 km of distribution lines spread over 178,200 sq km or 18% of the South Australian state. In comparison, Western Power handles transmission as well as distribution, serves around 896,000 customers and has around 85,000 km of circuits. Adjusting ETSA's figure pro rata for Western Power's slightly greater consumer numbers and increasing the expenditure to include transmission (using the same ratio of costs as that used by Western Power) gives an adjusted figure for ETSA of around $48 m. That compares reasonably well with Western Power's historical levels of expenditure on corporate costs but is half of the peak level of $96.6 m to which Western Power is projecting these costs to rise.

We noted also that a re-allocation of network support services costs had been made from transmission to distribution (as can be seen in the tables in the later sections of this report). [12] Western Power explained the cost allocation methodologies it had considered and decided on and provided us with further details. We were satisfied that the revised allocation was more appropriate than that assumed previously.

The combined IT&T and network support services opex accounts for around 33% of total opex and is thus material. We therefore discussed the revised estimates in detail with Western Power.

Table 2.6 analyses the movements in the estimates due to the revised proposals and shows that Western Power is now planning to spend an additional $10.7 m or 18% on IT&T opex during the period, compared to its earlier proposal. The additional expenditure is related mostly to the distribution business. Western Power has proposed a $21.6 m reduction in network support services costs from its original proposal but the reduction goes only part of the way to meeting the reduction of $45.4 m proposed in our Final Report for this expenditure category. [13]

Table 2.6: Movements in Opex Estimates ($ nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Proposed (Transmission + Distribution)				
IT&T	20.3	23.8	10.7	18
Network Support Services	71.8	64.6	-21.6	(10)
	92.0	88.4	-10.8	(4)
Our Recommendation	**Final Rpt**	**Now**		
IT&T	20.3	21.9	5.0	8
Network Support Services	56.7	56.7	0.0	-
	76.9	78.6	5.0	2

[11] Source: *South Australian electricity distribution price review prepared for Essential Services Commission of South Australia,* PB Associates, 2004. ETSA Utilities was chosen for the comparison because of its comparable size and the availability of recent detailed information on corporate costs.

[12] Table 4.2 (Revised v. Original Transmission Opex ($m nominal)) shows a drop in network support services expenditure of $63.3 m and Table 6.2 (Revised v. Original Distribution Opex ($m nominal)) shows an increase of $41.8 m in it.

[13] Comprised of recommended reductions of $17.7 m for transmission and $27.7 m for distribution.

IT&T Services

We discussed the estimates for IT&T services with Western Power and obtained further information on both the make-up and allocation of these costs.

We noted that Western Power's proposed IT&T opex is forecast to rise from $17.0 m in YE 2006 to $27.6 m in YE 2009, an increase that does not appear to match the focus in the business plans on getting new systems in place in exchange for long-term savings. Additionally, the amounts appeared excessive to us, noting that, based on 2,000 employees, they represented an annual cost of around $8,500 per employee in YE 2006 but around $13,800 in YE 2009. We also noted that most of the increase appeared to have come from an annual charge of $3.16 m that has apparently been levied to recover the cost of splitting the management information system (MIMS) run by the former Western Power Corporation into four separate systems for the separated businesses.

We found this cost category difficult to assess, as the IT&T business plans are not final. Adopting the same view as that taken for IT&T capex and after considering all the information made available to us, we decided not to agree to the full expenditure proposed. We then considered how a reasonable level of expenditure might be determined. We considered benchmarking for this purpose but were not convinced that it would give a robust result, given that Western Power is being reorganised and has no operating history as a stand-alone business; and given also that comparisons with other entities are difficult to make unless one is completely familiar with the circumstances of all the entities involved and is able to make detailed adjustments to the expenditures that are reported publicly. We decided, on balance, that additional expenditure of $5 m should be recommended instead of the $10.7 m requested. We also decided that $3 m of this should be allocated to the first year in the period and $2 m to the second.

The resulting recommended expenditures are shown in Table 2.5 and Table 2.6, together with a comparison with the expenditure recommended in our Final Report.

Network Support Services

In its original application, Western Power applied for a total of $215.3 m over the period for network support services for transmission and distribution. In our Final Report, we expressed concern about the level of increase from YE 2006 in its distribution component and the lack of supporting information for the increases, recommending a downward adjustment of $45.4 m for the period, giving a recommended expenditure level of $170.0 m. The reduction was made up of $17.7 m for transmission and $27.7 m for distribution. The reduced amount was accepted by the Authority and included in its draft decision.

In its revised proposals, Western Power has proposed expenditure of $193.7 m under this category, a reduction of $21.6 m or 10% from the original total of $215.3 m. The reduction of $21.6 m goes only part of the way to meeting the reductions proposed in our Final Report for this expenditure category.

We discussed this matter with Western Power and obtained further information on both the make-up and allocation of these costs. Western Power provided us with a breakdown of the proposed expenditure as shown in Table 2.7. The table shows that the four largest expenditure sub-categories – strategy and corporate affairs, insurance premiums and levies, human resources and finance – make up 80% of the total and all exhibit an increasing trend.

Table 2.7: Network Services Support Estimates ($m nominal)

	2007	2008	2009
CEO	0.8	0.9	0.9
Human resources	11.9	12.6	13.1
Finance	10.3	10.9	11.4
Business information	3.0	3.1	3.2
Strategy and corporate affairs	14.7	15.7	16.8
Design and estimating	1.8	1.8	1.9
Insurance premiums and levies	11.6	13.8	14.2
FBT	0.9	0.9	0.9
Rates and taxes	4.3	5.4	6.5
	59.5	65.3	69.0

Source: Western Power's supplementary information.

We noted that, based on 2,000 employees, the proposed expenditures represent an annual cost of around $30,300 per employee in YE 2006, rising to $34,500 in YE 2009.

We also noted that the expenditures are projected to rise from $59.4 m in YE 2007 to $69.0 m in YE 2009 and that, as already discussed, taking IT&T and network support services together, expenditures are projected to rise from $77.5 m in YE 2006 to $96.6 m in YE 2009.

This pattern of increase does not match our expectation that the business, once reorganised, will have the propensity to make material cost reductions as it continues to streamline its corporate functions and overheads. We would therefore expect to see a reduction, not an increase in these items, the only proviso being allowance for inflation and the transitional costs of reorganisation, reform and the necessary cultural change.

We noted that maintenance expenditures were forecast to reduce over the period and we would have expected to see a corresponding decrease in overhead expenditure. We also noted that productivity savings included in the business cases for IT&T included savings from both direct and overhead costs so there was an expectation within the company that there would be reductions in overheads.

Having considered the additional information provided, we retained the view that the revised proposed level of expenditure on network support services was still excessive. We considered benchmarking to help determine a reasonable level but as in the case of IT&T, decided that the best foundation was Western Power’s present level of expenditure in this category, now reported for YE 2006 to be $60.5 m. We decided, given that Western Power is presently being reorganised, to recommend no adjustment in the projected expenditures for the first year (YE 2007) since amongst other things the programmes for that year are already under way and there may be limited opportunity for the company to change its approach at this stage. However, we also decided that the view expressed in our Final Report on the total level of network services support opex over the period ($170 m) was still valid although we have modified its timing over the period to reflect the expectation of higher initial costs followed by efficiency gains. [14]

The resulting recommended expenditures are shown in Table 2.5 and Table 2.6, together with a comparison with the expenditure recommended in our Final Report.

2.3 New Investment Test and Capital Contribution Policy

The Authority asked us to provide an opinion on whether the proposed capital expenditure by Western Power meets or is likely to meet the new facilities investment test under the Code. In doing so, it noted that "*under the Authority's proposed treatment of capital contributions, any new facilities investment that is financed by a capital contribution will, ipso facto, be considered to meet the new facilities test*." However, this is not as straightforward as might first be thought.

We noted that an amendment to the Code in November 2005 deleted section 6.56 which provided that "*no amount may be added to the capital base in respect of any new facilities investment for which a capital contribution has been, or is to be, provided to the service provider*". This amendment permits the approach proposed by Western Power whereby investment funded by capital contributions is added to the capital base and the total amount of capital contributions is deducted from target revenue for the year. However, it appears to have created a conflict between compliance with the new facilities investment test and the calculation of capital contributions in accordance with the capital contribution policy as outlined below.

The new facilities investment test in the Code is outlined in section 6.52 as follows:

> "New facilities investment may be added to the capital base 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

[14] In commenting on our draft report, Western Power expressed the view in its email to the Authority of 15 August 2006 that the cuts recommended by us would take its expenditures below its YE 2007 levels and did not allow for essentially non-discretionary increases related to insurance premiums, rates and taxes or for escalation; that the comparison with ETSA Utilities was unsound; and that reductions in staff numbers to achieve the expenditure reductions had not been not anticipated in the disaggregation of Western Power. Our response to the Authority noted the following points. (a) The requirement of the Code is for an entity efficiently minimising costs and thus constraints on efficiency that arise from outside impositions are not necessarily a matter that should be taken into account by us or the Authority. (b) The Authority should not accept a "cost plus" approach but should seek demonstrable efficiency gains and cost minimisation. (c) The comparison with ETSA was not a determining factor but was used to illustrate that another similar entity is achieving much lower levels than Western Power projects. (d) The requirement is that expenditures reflect an entity efficiently minimising costs and we were not satisfied that Western Power's proposals do so. We considered that a new entity such as it should be able to find efficiencies in support costs and that usually that did mean fewer staff. We did not consider that it was our concern that this was not anticipated during disaggregation. We noted that Western Power's own business cases factor in savings in overhead costs (as well as in direct costs) as part of the proposed IT&T capital expenditure. We noted that maintenance costs are expected to fall over the period and that should result in a further saving in support costs. If efficiency gains can be found in maintenance activities, then why not in support costs as well. (e) It was not clear to us that all the costs claimed as non-discretionary were in fact so. For example, part of the rationale for the increased vegetation management expenditure was that it would reduce risk and result in lower insurance costs. (f) We retained the view that the company should be able to achieve the efficiency gains necessary to meet the network support services cost targets implicit in our recommended expenditure levels. In doing so, we note that the reduction implicitly targeted in network support services costs is around 7% p.a. in real terms from YE 2007 to YE 2008 and from YE 2008 to YE 2009. It may be said that this is a 'stretch goal' but our view is that this level of efficiency gain is possible. (g) If the Authority was of a mind to consider that it would take longer to achieve these gains, it would also need to take into consideration: (i) that the starting level of expenditure in network support services costs is well above historical levels of expenditure in this category of $38.6 m, $42.6 m and $47.9 m in YE 2003, YE 2004 and YE 2005 respectively, rising to a projected $60.5 m in YE 2006; (ii) our acceptance of the requested amount in YE 2007 recognises the expected initial restructuring costs need to achieve the later gains; and (iii) some of the restructuring costs may already have occurred and be reflected in the higher estimate now tabled by Western Power for YE 2006.

(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."

All capital expenditure is required to meet section (a) of the test and must meet at least one of the tests under section (b).

We considered which of the tests might be relevant to each category of capex and the extent to which Western Power had provided information on compliance with the test.

System Capacity Augmentation

Expenditure for system capacity augmentation to meet increased demand from load and customer growth would be tested under (b)(i).[15] If the expenditure were not fully justified under that test, it would need to be shown that it was required to *maintain* system reliability under (b)(iii).

For system capacity augmentation to achieve *improved* system reliability as opposed to maintaining it, the only applicable test is (b)(ii). It would have to be shown that the net economic benefit, (essentially the net present value of reduced lost load), exceeded the cost of the work in order to meet the test. [16]

Customer-Driven Investment

The applicable test for customer-driven investment is (b)(i). Revenue will be derived both from the customer paying TUOS or DUOS charges and from any capital contributions made.

The capital contributions policy is relevant here as it provides that the user shall only be required to fund that part of the investment that does not meet the new facilities investment test. This policy was presumably written to be consistent with the old section 6.56 that envisaged that investments funded by capital contributions were *not* to be included in the capital base. The intent was (and presumably remains) that the capital contribution is the total cost less the NPV of the future revenue stream: but the argument becomes circular with the total cost now becoming part of the capital base and having to meet the new facilities investment test.

To determine the amount of capital contribution requires consideration of the NPV of future revenue streams. It would thus appear that no investment financed by capital contributions could meet the new facilities investment test and be consistent with the capital contributions policy.[17] [18]

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15 This type of expenditure is not normally readily attributable to individual customers.

16 The distinction between these components – maintaining and improving – is not always readily achievable in practice.

17 Customer-driven work is usually funded partially by the service provider and partially by the customer, so the expenditure by the service provider will still need to be assessed. However, as part of assessing the total amount to be rolled in, the expenditure funded by the customer would also need to meet the test. Clearly, it will not, if eligible for a capital contribution.

18 The reasonableness of capital contributions demanded by a natural monopoly is another matter but its examination was outside the scope of our work.

Reliability Improvement Investment

For investment to *improve* system reliability, the only applicable test is (b)(ii). It would have to be shown that the net economic benefit, showing the value of reduction in lost load, exceeded the cost of the work to meet the test.

Asset Replacement Investment

The only applicable test is (b)(iii).

Safety, Environmental and Other Statutory Compliance Investment

The only applicable test is (b)(iii) although the Code is silent on statutory compliance matters other than in respect of safety and reliability.

Metering Investment

New metering could be tested under (b)(iii). Replacement metering could be covered under (b)(ii) as the cost of replacing is less than losing revenue from old and under-performing meters.

Support

This expenditure is required to achieve the other functions. Whilst it cannot be specifically tested under any of the tests, it does contribute to achieving the service provider's agreed targets.

Information Provided by Western Power

Western Power commented on compliance with the test as follows in its revised AAI.

> "Western Power concurs with the Authority's interpretation of the Code on this matter. Further information in relation to the new facilities investment test and the regulatory test is provided in Part D of this document. At this stage, however, it is important to note that the Code provides that forecast investment that is reasonably expected to meet the requirements of the new facilities investment test can be included in the capital base for the purposes of determining the company's revenue requirements.
>
> Western Power recognises that its current planning and investment process will need to be fine-tuned to accommodate formally the Code requirements in relation to the new facilities investment test and the regulatory test. For the purposes of this document, however, it is pertinent to consider whether the expenditure forecasts that are produced by the existing planning and investment process are reasonably expected to meet the requirements of the new facilities investment test. To address this question, we examine briefly each of the three elements of the new facilities investment test.
>
> In relation to the first element of the new facilities investment test, Western Power's capital contribution policy ensures that investment in relation to new connections will comply with this provision of the test. In particular, a capital contribution will be levied in respect of any connection that does not produce sufficient revenue to cover the incremental costs of that connection. In relation to the second element of the new facilities investment test, Western Power is proposing to undertake expenditure in relation to improving the reliability of supply.
>
> This expenditure is predominantly operating expenditure, and therefore is not subject to the new facilities investment test. In any event, as explained above, Western Power has regard to the likely benefits of improving reliability to ensure that any expenditure is cost-effective. In this sense, Western Power's reliability-related expenditure meets the spirit of the new facilities investment test, even though this test only applies to capital expenditure.
>
> In relation to the third element of the new facilities investment test it is noted that Western Power's planning and investment process takes account of the Technical Rules and other obligations prescribed by regulations and legislation12. In essence, the inclusion of these compliance obligations in the current planning and investment process is consistent with meeting this third leg of the test, namely to maintain "the safety or reliability of the covered network or its ability to provide contracted

> covered services". It is noted that a substantial proportion of Western Power's capital expenditure program is driven by compliance obligations.
>
> In summary, therefore, whilst Western Power's planning and investment process does not specifically incorporate the new facilities investment test, Western Power believes that its investment evaluation process broadly complies with the requirements of the test. It is further noted that the expenditure plans resulting from the planning and investment process will be further constrained by resourcing and financing considerations. The additional constraints on expenditure will ensure that projects will only proceed if they are compliance-related or produce high net benefits.
>
> This should provide further confidence that Western Power's capital expenditure program satisfies the requirements of the new facilities investment test. Further details of Western Power's expenditure forecasts are provided in Parts B and C of this document. This information will further support Western Power's view that the proposed capital expenditure complies with the requirements of the new facilities investment test."

Our Comments

We concur with Western Power's view that carrying out the tests on individual expenditure items as this early stage is not practical, given not only the work and time involved but also the fact that individual expenditure items will not yet have been formulated, costed or evaluated fully by the company.

We also note in respect of part (b) of the test that in our experience it is usually possible to show a positive result when applying investment tests of this type, at least at the distribution level, once all benefit streams are identified and the costs apportioned to them. This assumes that reasonable capital contributions are permitted in cases where the development is marginal or uneconomic. (This is not to say that the identification of benefit streams and the apportionment of costs to them is not a subjective matter.) It is usually equally possible to show positive results at the transmission level although there is a greater need, at that level, to ensure that projects have been optimised and are matched to load growth and generation plans.

Given that capital contributions are permitted, the stated "reasonable expectation" that part (b) of the test will be complied with is therefore likely, in our opinion, to be found later to have been a fair assessment – all the more so, perhaps, given the apparent high level of Western Power's projected customer capital contributions. [19]

[19] We discuss other matters relating to customer capital contributions in section 5.2.

3 Transmission Capex

Matters are reviewed in this section of the report only to the extent that they are affected by the changes made by Western Power in its revised proposed access arrangement of 19 May 2006. In all other respects, the findings and recommendations of our Final Report remain unaltered.

3.1 Revised Expenditure Proposals

Western Power has now proposed $645.2 m of transmission capex over the period compared to its original proposal of $514.7 m. Updated forecasts for the YE 2006 have also been presented, with expenditure that year now forecast to be $201.2 m compared with the earlier forecast of $191.0 m. Year-by-year original and revised forecast expenditure is shown in Table 3.1.

Table 3.1: Original and Revised Proposed Transmission Capex ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Network - demand related								
System capacity	81.2	83.0	103.4	110.5	87.3	81.2	107.5	107.0
Customer driven (bulk loads)	12.7	17.4	2.7	0.0	5.8	29.2	55.3	12.2
Customer driven (generation)	71.6	47.9	25.7	20.1	79.1	68.3	40.8	24.7
	165.4	148.3	131.8	130.6	172.2	178.7	203.6	143.9
Network - non-demand related								
Asset replacement	9.1	9.9	13.5	18.0	9.0	9.9	13.5	18.0
Safety, environmental and statutory	5.1	5.4	8.1	8.1	4.2	5.4	8.1	8.1
Reliability driven	1.2	1.8	1.8	1.8	1.6	1.8	1.8	1.8
	15.4	17.1	23.4	27.9	14.8	17.1	23.4	27.9
Other								
SCADA and communications	3.4	3.2	1.5	3.4	4.9	3.2	1.5	3.4
IT including market reform	2.6	5.9	4.2	4.8	0.9	5.9	4.2	4.8
Support	4.2	4.5	4.1	4.1	8.4	4.5	4.1	4.1
Generation tariff meters	0.0	0.0	0.0	0.0	0.0	4.0	5.3	0.0
Wholesale market a/	0.0	0.0	0.0	0.0	0.0	0.1	3.7	1.9
	191.0	**178.9**	**165.0**	**170.8**	**201.2**	**213.4**	**245.8**	**185.9**

Source of original data: Western Power (as amended, November 2005) and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.
a/ This item of $5.72 m for wholesale market software was included in the revised proposal but subsequently withdrawn.

Table 3.2 shows that the changes are an increase in customer-driven work and the addition of a new item for generation metering. A further item for wholesale market software was withdrawn by Western Power. Table 3.2 summarises the changes.

Table 3.2: Revised v. Original Transmission Capex ($m nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Network - demand related				
System capacity	99.0	98.6	-1.2	(.4)
Customer driven (bulk loads)	6.7	32.2	76.6	383
Customer driven (generation)	31.2	44.6	40.1	43
	136.9	175.4	115.5	28
Network - non-demand related				
Asset replacement	13.8	13.8	0.0	-
Safety, environmental and statutory	7.2	7.2	0.0	-
Reliability driven	1.8	1.8	0.0	-
	22.8	22.8	0.0	-
Other				
SCADA and communications	2.7	2.7	0.0	-
IT including market reform	4.9	4.9	0.0	-
Support	4.2	4.2	0.0	-
Generation tariff meters	0.0	3.1	9.3	a/
Wholesale market b/	0.0	1.9	5.7	a/
	171.6	215.1	130.5	25

a/ Previously zero so percentage increase not applicable. This item has since been withdrawn.
b/ We were advised that this item has since been withdrawn by Western Power.

3.2 Assessment

Customer-Driven Expenditure

The increase in customer-driven bulk load expenditure of $76.6 m over the period is accounted for entirely by the addition of one project, the Boddington mine, to the list. The increase in customer-driven generation-related work is accounted for entirely by the addition of another project, Neerabup terminal station. We reviewed Western Power's internal approval papers for these two projects and considered the plans and expenditures reasonable whilst noting that a detailed engineering and economic assessment of them was beyond the scope of our work. We noted that their expenditures and timing are contingent on customer and generator plans and we presume that both will be financed in whole or in part by contributions.

In the case of Neerabup, the supplementary information given to us indicates that the project cost of $40.1 m includes $0.647 m of expenditure in YE 2006. In our opinion, that amount ought not to be included in the estimates for the period and we have recommended an adjustment to remove it.

Other than noting that the Authority may wish to satisfy itself that the Neerabup project is actually 'committed' in accordance with the definition of commitment in the Code (and thus, as proposed by Western Power, ought not to be subject to a regulatory test) we have no other comment to make on these items.

Generation Tariff Meter Expenditure

Western Power advised us that the proposed expenditure on generation tariff meters was included in its projections at the direction of the governmental task force responsible for directing the restructuring of Western Power Corporation.[20] We have no objection to the estimated amount but note that the Authority may wish to corroborate the statement before approving this item. It may also wish to consider whether additional revenue will be earned from market participants in relation to it.

3.3 Recommended Transmission Capex

No adjustments were recommended in our Final Report in respect of transmission capex. However, taking into account the matters discussed in this section of the report, the level of transmission capex now recommended is as shown in Table 3.3.

Table 3.3: Revised Recommended Level of Transmission Capex ($m nominal)

YE 30 June	Updated Forecast	Revised Proposal		
	2006	2007	2008	2009
Capex proposed by Western Power	201.2	213.4	245.8	185.9
Wholesale market capex withdrawn		0.1	3.7	1.9
Adjustment to customer-driven work		0.687		
Recommended transmission capex		212.6	242.1	184.0

In all other respects, the findings and recommendations in our Final Report in respect of transmission capex remain unchanged.

20 We did not seek corroboration of this statement but did rely on it.

4 Transmission Opex

Matters are reviewed in this section of the report only to the extent that they are affected by the changes made by Western Power in its revised proposed access arrangement of 19 May 2006. In all other respects, the findings and recommendations of our Final Report remain unaltered.

4.1 Revised Expenditure Proposals

Western Power has now proposed $196.4 m of transmission opex over the period compared to its original proposal of $248.8 m. Updated forecasts for the YE 2006 have also been presented, with expenditure that year now forecast to be $69.6 m compared with the earlier forecast of $71.2 m. Year-by-year original and revised forecast expenditure is shown in Table 4.1.

Table 4.1: Original and Revised Proposed Transmission Opex ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Maintenance Strategy	3.9	4.0	4.1	4.2	3.6	4.0	4.1	4.2
Preventative Condition	6.2	6.0	6.1	6.2	10.0	6.1	6.2	6.4
Preventative Routine	8.7	8.1	8.3	8.5	10.1	8.4	8.6	8.8
Corrective Deferred	2.0	2.1	1.9	1.9	4.0	2.3	2.1	2.0
Corrective Emergency	1.0	1.0	0.9	0.9	1.4	1.0	0.9	0.9
Maintenance (Total)	21.9	21.2	21.3	21.7	29.1	21.8	21.9	22.3
SCADA & Communications	5.3	5.4	5.6	5.7	3.2	5.4	5.6	5.7
Network Operations	9.5	12.1	13.3	13.2	9.5	10.0	10.9	10.9
IT&T	6.2	6.6	7.3	7.8	6.3	7.5	8.2	8.8
Misc. Network Services	0.0	0.0	0.0	0.0	6.4	4.2	4.4	4.5
Network Support	28.3	31.6	35.5	40.6	15.1	13.6	15.2	15.5
Transmission Total a/	**71.2**	**76.9**	**82.9**	**89.0**	**69.6**	**62.6**	**66.2**	**67.8**

Source of original data: Western Power and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.
a/ There is a minor discrepancy between the updated 2006 total given on p.78 of Appendix 6 of the AAI and that on p.7.

Table 4.2 shows that the main changes are decreases in network support and network operations costs and an increase arising from the inclusion of a new item, miscellaneous network services. It relates to services provided to third parties and will presumably be offset by cost recovery through charges. Minor increases are proposed for maintenance and IT&T costs.

We note that Western Power has maintained its objective of delivering opex efficiency gains for the network business as a whole of $20 m p.a. by the end of the period.

Table 4.2: Revised v. Original Transmission Opex ($m nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Maintenance Strategy	4.1	4.1	0.0	()
Preventative Condition	6.1	6.2	0.4	2
Preventative Routine	8.3	8.6	0.9	3
Corrective Deferred	2.0	2.1	0.5	9
Corrective Emergency	0.9	0.9	0.0	2
Maintenance (Total)	21.4	22.0	1.8	3
SCADA & Communications	5.6	5.6	0.0	-
Network Operations	12.9	10.6	-6.8	(18)
IT&T	7.2	8.2	2.8	13
Misc. Network Services	0.0	4.4	13.1	a/
Network Support	35.9	14.8	-63.3	(59)
Transmission Total	82.9	65.5	-52.4	(21)

a/ Previously zero so percentage increase not applicable.

4.2 Direct Expenditure

Maintenance

Western Power has proposed a small increase in the level of transmission maintenance expenditure for the period. The increase is attributed to escalation of labour rates and unit rates for maintenance activities. We noted that for YE 2006 the latest maintenance expenditure forecast of $29.1 m is considerably above the earlier forecast of $21.9 m for that year but that the increased level is not projected to continue. We discussed the basis of the cost increases with Western Power and accepted them as reasonable.

Network Operations

The network operations expenditure reported in the tables above is the transmission-related share of the costs of the systems operations group that provides control, switching, operations planning and monitoring for the transmission and the distribution networks. In our Final Report, we recommended an adjustment to network operations expenditure that related to system management activities and that we were advised should be removed from the forecast expenditures in the access arrangement, as it was recoverable from market participants via a separate mechanism under the wholesale electricity market rules. Western Power's revised expenditure proposals reflect that adjustment and there is no other material change in this item.

Miscellaneous Network Services

This new expenditure item has been added since the August 2005 access arrangement proposal was submitted. The total proposed expenditure is $13.1 m over the period. The expenditure covers the provision of miscellaneous network services to customers, including the relocation of assets, planning studies, network switching and isolation services. This expenditure is or should be recovered by charges and thus ought to have a neutral impact on the tariff agreed under the access arrangement.

We understand that the proposed expenditure reflects historical levels of service provision, noting that the associated costs and revenues were not included in the earlier projections. We accept this category as reasonable on this basis.

4.3 Indirect Expenditure

The proposed increases in IT&T and network support services expenditure have been discussed in section 2.2.

4.4 Recommended Transmission Opex

In our Final Report, we had considered Western Power's proposed transmission opex to be reasonable, subject to the comments made and to adjustments reported in section 6.5 of that report. Having considered the revised proposals presented by Western Power, we maintain the same opinion as in our Final Report but with adjustments to reflect the new estimates as set out below.

The level of transmission opex recommended in our Final Report was as shown in Table 4.3.

Table 4.3: Recommended Level of Transmission Opex (FINAL REPORT) ($m nominal)

YE 30 June	Forecast	Proposed		
	2006	2007	2008	2009
Opex proposed by Western Power	71.2	76.9	82.9	89.0
Network operations adjustment	0.0	-2.1	-2.3	-2.3
Network support services adjustment	0.0	-2.5	-5.5	-9.7
Recommended transmission opex	71.2	72.3	75.1	77.0

The level of transmission opex now recommended is as shown in Table 4.4.

Table 4.4: Revised Recommended Level of Transmission Opex ($m nominal)

YE 30 June	Updated Forecast	Revised Proposal		
	2006	2007	2008	2009
Opex proposed by Western Power	69.6	62.6	66.2	67.8
Network support services adjustment		0.0	-2.2	-3.2
Recommended transmission opex		62.6	63.9	64.6

In all other respects, the findings and recommendations in our Final Report in respect of transmission opex remain unchanged.

5 Distribution Capex

Matters are reviewed in this section of the report only to the extent that they are affected by the changes made by Western Power in its revised proposed access arrangement of 19 May 2006. In all other respects, the findings and recommendations of our Final Report remain unaltered.

5.1 Revised Expenditure Proposals

Western Power has now proposed $882.6 m of distribution capex over the period compared to its original proposal of $767.3 m. Updated forecasts for YE 2006 have also been presented, with expenditure that year now forecast to be $288.2 m compared with the earlier forecast of $229.2 m. Year-by-year original and revised forecast expenditure is shown in Table 5.1.

Table 5.1: Original and Revised Proposed Distribution Capex ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Network - demand related								
Distribution capacity	33.3	30.2	34.0	40.3	34.7	31.3	34.0	40.3
Customer driven	84.5	84.5	84.5	84.5	142.9	92.7	110.5	129.1
Vested assets	17.2	19.6	21.9	24.3	15.5	19.6	21.9	24.3
	135.0	134.3	140.4	149.1	193.1	143.6	166.4	193.7
Network - non-demand related								
Asset replacement	10.3	10.3	10.0	19.0	14.4	10.3	10.0	19.0
Reliability driven	7.7	7.7	12.0	21.9	2.9	7.7	12.0	21.5
Safety, environmental and statutory	23.9	28.2	40.0	44.7	30.3	30.2	41.7	44.7
State Undergrounding Program (SUPP)	17.1	17.1	16.3	17.1	13.6	17.1	16.3	17.1
Rural Power Improvement Program (RPIP)	10.3	10.3	10.6	0.0	6.0	10.3	10.6	12.0
	69.2	73.5	88.9	102.7	67.2	75.5	90.6	114.3
Other								
SCADA and communications	2.1	2.1	1.8	1.9	2.6	2.1	1.8	1.9
IT including market reform	15.2	15.2	11.4	13.0	8.4	25.7	18.3	15.6
Metering	4.4	4.4	8.1	10.0	11.1	4.4	8.1	10.0
Support	3.2	3.2	3.5	3.8	5.8	3.2	3.5	3.8
	229.2	**232.7**	**254.0**	**280.5**	**288.2**	**254.6**	**288.7**	**339.3**

Source of original data: Western Power AAI, table 17, p. 110 and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.

Table 5.2 analyses the changes and shows that they comprise an increase in customer-driven work and in IT&T spending, along with an extension of the rural power improvement programme (RPIP) and other minor adjustments.

Table 5.2: Revised v. Original Distribution Capex ($m nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Network - demand related				
Distribution capacity	34.8	35.2	1.1	1
Customer driven	84.5	110.8	78.9	31
Vested assets	21.9	21.9	0.0	-
	141.2	167.9	80.0	19
Network - non-demand related				
Asset replacement	13.1	13.1	0.0	-
Reliability driven	13.9	13.7	-0.4	(1)
Safety, environmental and statutory	37.6	38.9	3.7	3
State Undergrounding Program (SUPP)	16.8	16.8	0.0	-
Rural Power Improvement Program (RPIP)	7.0	11.0	12.0	58
	88.4	93.5	15.4	6
Other				
SCADA and communications	1.9	1.9	0.0	-
IT including market reform	13.2	19.9	20.0	51
Metering	7.5	7.5	0.0	-
Support	3.5	3.5	0.0	-
	255.8	294.2	115.3	15

5.2 Assessment

Customer-Driven Expenditure

The increase in customer-driven expenditure of $78.9 m over the period is accounted for mainly by Western Power's revised estimates of this category in light of its interpretation of the revised draft Technical Rules that have been promulgated. We noted that the estimated cost of implementing the earlier draft Technical Rules was stated in Western Power's original submission and reported in our Final Report as tentatively around $43 m. Clearly, the uplift now included in the estimates is much greater.

A contributing factor may be that Western Power's original proposal showed the same level of expenditure in all subsequent years as it did for YE 2006 – see Table 5.1 – suggesting that up-to-date data had not been used in this expenditure category in the original estimates and that they were under-stated as a result.

Not withstanding the uplift, the revised estimates may still be understated, given the greatly increased level of expenditure now reported for YE 2006 compared with the much lower levels in each of the following three years – $142.9 m in YE 2006 but only $92.7 m, $110.5 m and $129.1 m respectively in YE 2007 to YE 2009.

It therefore again appears that expenditures in this category during the access arrangement period will be under-stated if the present level of customer growth continues.

The Authority may wish to note this point as the understatement of the expenditures and the accompanying contributions may distort the regulatory accounts.

We also note for completeness that the Technical Rules are not yet final and so further changes in the estimates may be required when they are promulgated in their final form.

IT&T Expenditure Including Market Reform

The proposed increase in IT&T expenditure has been discussed in section 2.2.

Extension of RPIP Programme

The projected extension of the RPIP programme for the last year of the period is the reason for the increase in this category. Western Power advised us that they had received an indication from the Government that the programme was to be extended. However, we noted that Western Power expect to spend only $6.0 m in YE 2006 against the budget of $10.0 m.

Other Changes

The other changes in proposed distribution capex were not material but were reviewed and accepted as reasonable.

5.3 Recommended Distribution Capex

No adjustments were recommended in our Final Report in respect of distribution capex. However, taking into account the matters discussed in this section of the report, the level of distribution capex now recommended is as shown in Table 5.3.

Table 5.3: Revised Recommended Level of Distribution Capex ($m nominal)

YE 30 June	Updated Forecast	Revised Proposal		
	2006	2007	2008	2009
Capex proposed by Western Power	288.2	254.6	288.7	339.3
IT&T adjustment		-4.5	-1.9	-2.6
Recommended distribution capex		250.1	286.8	336.7

In all other respects, the findings and recommendations in our Final Report in respect of distribution capex remain unchanged.

6 Distribution Opex

Matters are reviewed in this section of the report only to the extent that they are affected by the changes made by Western Power in its revised proposed access arrangement of 19 May 2006. In all other respects, the findings and recommendations of our Final Report remain unaltered.

6.1 Revised Expenditure Proposals

Western Power has now proposed $606.8 m of distribution opex over the period compared to its original proposal of $484.8 m. Updated forecasts for the YE 2006 have also been presented, with expenditure that year now forecast to be $196.4 m compared with the earlier forecast of $155.2 m. Year-by-year original and revised forecast expenditure is shown in Table 6.1.

Table 6.1: Original and Revised Proposed Distribution Opex ($m nominal)

YE 30 June	Forecast (Aug 05)	Original Proposal			Updated Forecast	Revised Proposal		
	2006	2007	2008	2009	2006	2007	2008	2009
Maintenance Strategy	5.8	6.3	6.3	6.4	5.3	6.3	6.3	6.3
Preventative Condition	18.4	13.5	13.8	14.3	18.7	23.0	23.3	22.8
Preventative Routine	23.8	23.3	23.9	24.8	28.1	30.3	30.9	31.8
Corrective Deferred	15.1	11.9	11.1	10.9	18.4	12.4	11.6	11.4
Corrective Emergency	27.5	22.4	21.0	20.5	34.9	27.4	25.9	25.4
Maintenance (Total)	90.5	77.3	76.0	76.8	105.3	99.3	98.0	97.7
Reliability	3.7	4.5	4.5	4.5	2.1	4.5	4.5	4.5
SCADA & Communications	0.8	0.9	0.9	0.9	0.8	0.9	0.9	0.9
Network Operations	7.2	8.5	8.8	9.2	8.5	8.8	9.3	9.7
IT&T	10.5	11.2	12.8	15.1	10.7	13.3	14.9	18.8
Metering	11.7	14.4	14.4	15.9	15.9	14.4	14.4	15.9
Call Centre	5.7	6.6	6.9	7.2	5.7	6.6	6.9	7.2
Misc. Network Services	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.1
Network Support	25.1	33.0	37.4	37.3	45.4	45.8	50.1	53.5
Distribution Total a/	**155.2**	**156.2**	**161.6**	**166.9**	**196.4**	**195.5**	**200.9**	**210.3**

Source of original data: Western Power and our Final Report.
Source of 2006 updated forecast and revised proposal: Western Power revised AAI Appendix 6.
a/ There is a minor discrepancy between the updated 2006 total given on p.134 of Appendix 6 of the AAI and that on p.7.

Table 6.2: shows that the changes are an increase in maintenance,[21] IT&T and network support costs and an increase arising from the inclusion of a new item, miscellaneous network services. A minor increase is proposed for network operations costs. As in the case of transmission opex, it relates to services provided to third parties and will presumably be offset by cost recovery through charges.

We note that Western Power has maintained its objective of delivering opex efficiency gains for the network business as a whole of $20 m p.a. by the end of the period.

[21] On p.46 of our Final Report, we described the then projected increase in maintenance and reliability expenditure as modest.

Table 6.2: Revised v. Original Distribution Opex ($m nominal)

YE 30 June	Average Annual Original	Average Annual Revised	Increase in 3-yr Totals	Increase in 3-yr Avge (%)
Maintenance Strategy	6.3	6.3	-0.1	(.5)
Preventative Condition	13.9	23.0	27.5	66
Preventative Routine	24.0	31.0	21.1	29
Corrective Deferred	11.3	11.8	1.6	5
Corrective Emergency	21.3	26.2	14.8	23
Maintenance (Total)	76.7	98.4	64.9	28
Reliability	4.5	4.5	0.0	-
SCADA & Communications	0.9	0.9	0.0	-
Network Operations	8.8	9.3	1.3	5
IT&T	13.0	15.7	7.9	20
Metering	14.9	14.9	0.0	-
Call Centre	6.9	6.9	0.0	-
Misc. Network Services	0.0	2.0	6.1	a/
Network Support	35.9	49.8	41.8	39
Distribution Total	161.6	202.3	122.0	25

a/ Previously zero so percentage increase not applicable.

6.2 Direct Expenditure

Maintenance

Western Power is proposing an increase of $64.9 m or 28% in the level of distribution maintenance expenditure for the period. Of importance, it is reporting a revised estimate of YE 2006 maintenance costs of $105.3 m compared with its August 2005 forecast of $90.5 m. It advised us that its forecast expenditure for the period has been revised in light of the contracts it has let since preparing its earlier estimate and that other cost increases that have occurred. The main reasons cited for the increased estimate and discussed with us were these.

- An expanded vegetation management programme has now been in operation for several months with a new contractor and considerable new evidence is now available on the scope of work required. This item accounts for $31.0 m of the proposed increase.
- Increased pole inspections and additional pole maintenance is proposed; and the addition of another 23,000 poles in the inspection programme that had been left out of the original forecasts, accounts for a further $10.3 m of the proposed increase.
- An additional $14.7 m has been allowed for primary emergency response work. This item has been reassessed, based on recent activity levels and expenditures.
- An additional $3.3 m for street light lamp replacements has been budgeted. (We note that the cost of this work will or presumably ought to be recovered through the street light contract).
- An additional $4.3 m has been added due to cost increases in other programmes and some additional regulatory requirements.

Table 6.3 shows the historical pattern of maintenance expenditure and the levels now proposed for the period.

Table 6.3: Historical v. Revised Maintenance Opex ($m nominal)

YE 30 June	Actual			Revised Forecast	Revised Proposal		
	2003	2004	2005	2006	2007	2008	2009
Maintenance strategy	3.0	3.6	3.8	5.3	6.3	6.3	6.3
Preventative condition	8.6	8.9	16.3	18.7	23.0	23.3	22.8
Preventative routine	8.9	9.3	26.6	28.1	30.3	30.9	31.8
Corrective deferred	13.2	13.3	15.8	18.4	12.4	11.6	11.4
Corrective emergency	30.6	27.0	30.0	34.9	27.4	25.9	25.4
Maintenance (Total)	64.3	62.1	92.5	105.3	99.3	98.0	97.7

Expenditure on maintenance and reliability has increased significantly over the last few years. The increase has been principally in preventative maintenance as Western Power recognised that its previous level of expenditure in this category was leading to deterioration in network performance and an increase in reactive emergency maintenance requirements. This trend is forecast to continue with the latest expenditure proposals containing a further increase in preventative maintenance. However, corrective maintenance is not now predicted to reduce as quickly as in the previous proposal.

We reviewed the reasons given by Western Power for the increase and for the increases in YE 2006 maintenance expenditure. We accepted the explanations, noting that expenditure is forecast to trend down over the period as the benefits of an improved preventative maintenance programme lead to reductions in corrective maintenance. We have also noted that Western Power is targeting improvements in network performance over the period.

As a further check, we calculated the ratio of maintenance expenditure p.a. to network investment as shown in Table 6.4.

Table 6.4: Maintenance v. Network Investment

YE 30 June	Revised Forecast	Revised Proposal		
	2006	2007	2008	2009
Network investment at RC ($m)	3,058	5,022	3,688	4,096
Maintenance ($m p.a.)	105.3	99.3	98.0	97.7
Maintenance as pct. of network investment	3.4%	2.0%	2.7%	2.4%

a/ Assumed to be twice the depreciated RC or two times the RAB.

Annual maintenance expenditure as a percentage of network investment is forecast to fall from 3.4% in YE 2006 to 2.4% by YE 2009. Whilst care is needed when drawing conclusions from a benchmark such as this, we accept that the level is appropriate for Western Power at the present time. However, we would expect to see the level of maintenance expenditure fall further in the next period after the present drive on remedial work has taken effect.

Reliability

No change proposed in reliability expenditure but in the original proposal, no explanation was given of the expenditure under this category and we incorrectly assigned it to reliability improvement. The explanation given in the revised proposal is that it is the cost of the extended outage penalty scheme. The estimate is based on 20,000 claims p.a. and equates to a cost per claim of $225. [22]

Network Operations

In its original application, Western Power applied for a total of $26.5 m over the period for Network Operations. In our Final Report, we expressed concern about the level of increase from YE 2006 and the lack of supporting information for the increases, recommending a downward adjustment of $3.7 m for the period, giving a total of $22.8 m. The reduced amount was accepted by the Authority and included in its draft decision. In its revised proposals, Western Power has proposed expenditure of $27.8 m under this category, an increase of $5.0 m compared to the draft decision, and $1.3 m compared to its original proposal. We noted that the forecast for YE 2006 had also increased from the earlier forecast of $7.2 m to $8.5 m.

Detailed explanations of the increase have been provided in the revised proposal and in supporting information given to us. The reasons include the introduction of centralised network operations in line with best practice to improve safety, consistency and quality of work and increased operations activities to allow safe access to the network for the increased level of capital and maintenance activities.

We accept that the changes in operation are appropriate given the increased work levels on the system and the targeting of improved network performance and safety.

Miscellaneous Network Services

This new expenditure item has been added since the August 2005 access arrangement proposal was submitted. The total proposed expenditure is $6.1 m over the period. The expenditure covers the provision of a number of miscellaneous network services to customers, including the relocation of assets, planning studies, network switching and isolation services, temporary builders' supplies and safety escorts for the transportation of high loads. This expenditure is or should be recovered by charges and thus ought to have a neutral impact on the tariff agreed under the access arrangement.

We understand that the estimate reflects historical levels of service provision, noting that the associated costs and revenues were not included in the earlier projections. We accept this category as reasonable on this basis.

6.3 Indirect Expenditure

The proposed increases in IT&T and network support services expenditure have been discussed in section 2.2.

6.4 Recommended Distribution Opex

In our Final Report, we had considered Western Power's proposed distribution opex to be reasonable, subject to the comments made and to adjustments reported in section 8.6 of that report. Having considered the revised proposals presented by Western Power, we maintain

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[22] See p. 146 of the AAI, Appendix 6 that reads, "An operating expenditure provision of $4.5 million per annum has been made relating to the forecast cost to be incurred as direct result of the implementation of the Extended Outage Penalty Scheme, an element of the Electricity Industry (Network Quality and Reliability of Supply) Code, 2005. The forecasts are based on estimates of 20,000 claims received over a 12-month period and include all the necessary related resources (staff and systems) required to administer the scheme. Figure 101 illustrates that this is a relatively new expenditure category introduced in [YE 2006], specifically to cater for the Extended Outage Penalty Scheme."

the same opinion as in our Final Report but with adjustments to reflect the new estimates as set out below.

The level of distribution opex recommended in our Final Report was as shown in Table 6.5.

Table 6.5: Recommended Level of Distribution Opex (FINAL REPORT) ($m nominal)

YE 30 June	Forecast	Proposed		
	2006	2007	2008	2009
Opex proposed by Western Power	155.2	156.2	161.6	166.9
Network operations adjustment		-1.1	-1.2	-1.4
Network support services adjustment		-7.1	-10.7	-9.8
Recommended distribution opex		148.0	149.7	155.7

The level of distribution opex now recommended is as shown in Table 6.6.

Table 6.6: Revised Recommended Level of Distribution Opex ($m nominal)

YE 30 June	Updated Forecast	Revised Proposal		
	2006	2007	2008	2009
Opex proposed by Western Power	196.4	195.5	200.9	210.3
IT&T adjustment		0.0	-1.0	-4.7
Network support services adjustment		0.0	-6.4	-11.9
Recommended distribution opex		195.4	193.5	193.6

In all other respects, the findings and recommendations in our Final Report in respect of distribution opex remain unchanged.

7 Adjustment of Initial Capital Base

7.1 Revised Adjustment

Western Power provided us with a document outlining the differences in the transmission and distribution initial capital bases presented in the proposed access arrangement information (referred to as the AAI in this section of the report) and the revised proposed AAI.[23] It is reproduced below.

Transmission Initial Capital Base

The transmission initial capital base presented in the proposed AAI was:

Table 10: Derivation of transmission *capital base* value ($m in nominal terms)

	Year ending 30 June					
	2004	2005	2006	2007	2008	2009
Year of first access arrangement period				1	2	3
Opening capital base value	-	1,132	1,213	1,369	1,528	1,677
plus Escalation	-	25	30	33	37	40
plus Capital Expenditure	-	99	173	177	169	167
less Depreciation	-	43	47	52	57	61
less Disposals	-	0	0	0	0	0
Closing capital base value	1,132	1,213	1,369	1,528	1,677	1,823

The transmission initial capital base presented in the revised proposed AAI was:

Table 11 - Derivation of Transmission Initial Capital Base (net)
($ million real as at 30 June 2006)

Financial year ending:	**30 June 2004**	**30 June 2005**	**30 June 2006**
Opening capital base value		1,193.4	1,261.5
less Depreciation		42.9	45.2
plus Capital Expenditure (net)		111.0	180.3
less Redundant Assets		0.0	0.0
plus Corporate Assets allocated to Western Power		0.0	8.0
Closing capital base value	**1,193.4**	**1,261.5**	**1,404.5**

Real v. Nominal Amounts

The information presented in the proposed AAI was in nominal terms but the information presented in the revised proposed AA[I] is in real terms. The following table represents table 10 of the proposed AAI in real terms ($m at 30 June 2006).

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23 *Asset valuation information for Wilson Cook &Co*, July 2006.

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,193.4	1,251.0
less Depreciation		44.2	47.0
plus Capital Expenditure (net)		101.9	173.0
less Redundant Assets		0.0	0.0
Closing capital base value	1,193.4	1,251.0	1,377.0

The following table presents the differences in the transmission capital base value between the proposed AAI and the revised proposed AAI in real terms.

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		0.0	10.5
less Depreciation		-1.3	-1.8
plus Capital Expenditure (net)		9.2	7.3
less Redundant Assets		0.0	0.0
Closing capital base value	0.0	10.5	27.5

Methodology

The derivation of the initial capital base in the proposed AAI followed the asset roll-forward methodology presented in sections 2.3.2 of appendix 7 of the proposed access arrangement. That approach was in nominal terms and assumed that capital expenditure occurred half way through the year. Under this approach, non-network assets were treated differently with the asset values not being adjusted for inflation. The derivation of the initial capital base in the revised proposed AAI follows the approach taken in the revenue modelling. This approach is undertaken in real terms with all cash flows assumed at the end of the year.

Depreciation

The derivation of the depreciation in the proposed AAI followed the asset roll-forward methodology presented in sections 2.3.3 of appendix 7 of the proposed AA. The derivation of the initial capital base in the revised proposed AAI follows the approach taken in the revenue modelling. This approach is to use the remaining life of the asset to determine the depreciation applicable.

Capital Expenditure

The increase in capital expenditure from $101.9 m to $111.0 m in YE 2005 is due to an adjustment to the actual capital expenditure for YE 2005 following reconciliation of the YE 2005 accounts that was not included in the proposed access arrangement. The increase in capital expenditure from $173.0 m to $180.3 m in YE 2006 is due to revised forecasts being available based on actual expenditure for the year until the end of April 2006.

Section 6.2 of the revised proposed access arrangement acknowledges that the capital expenditure in YE 2006 is a forecast and details the methodology that Western Power will utilise to ensure Western Power is economically neutral for any forecast error.

Corporate Asset Allocation

As a part of the split of Western Power Corporation into four separate businesses, Western Power was gifted a number of assets that had previously not been included in the initial capital base. Detail of these assets is presented in Table 11a of the revised proposed AAI.

Distribution Initial Capital Base

The distribution initial capital base presented in the proposed AAI was:

Table 21: Derivation of distribution capital base value (nominal $m)

	Year ending 30 June					
	2004	2005	2006	2007	2008	2009
Year of first access arrangement period				1	2	3
Opening capital base value	-	1,315	1,410	1,482	1,655	1,846
plus Escalation	-	30	34	36	40	45
plus Capital Expenditure	-	152	127	233	254	280
less Depreciation	-	83	86	92	99	107
less Disposals	-	5	3	4	4	4
Closing capital base value	1,315	1,410	1,482	1,655	1,846	2,060

The distribution initial capital base presented in the revised proposed AAI was:

Table 29: Derivation of Distribution Initial Capital Base (net)
($ million real as at 30 June 2006)

Financial year ending:	**30 June 2004**	**30 June 2005**	**30 June 2006**
Opening capital base value		1,387.0	1,452.9
less Depreciation		85.6	89.9
plus Capital Expenditure (net)		156.6	160.5
less Redundant Assets		5.1	2.9
plus Corporate Assets allocated to Western Power		0.0	8.0
Closing capital base value	**1,387.0**	**1,452.9**	**1,528.6**

Real v. Nominal Amounts

The information presented in the proposed AAI is in nominal terms where as the information presented in the revised proposed access arrangement is in real terms. The following table represents table 21 of the proposed AAI in real terms ($m at 30 June 2006).

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		1,387.0	1,453.6
less Depreciation		84.9	85.8
plus Capital Expenditure (net)		156.6	126.8
less Redundant Assets		5.1	2.9
Closing capital base value	1,387.0	1,453.6	1,491.7

The following table presents the differences in the distribution capital base value between the proposed AAI and the revised proposed AAI in real terms.

Financial year ending:	30 June 2004	30 June 2005	30 June 2006
Opening capital base value		0.0	-0.7
less Depreciation		0.7	4.1
plus Capital Expenditure (net)		0.0	33.7
less Redundant Assets		0.0	0.0
Closing capital base value	0.0	-0.7	36.9

Methodology and Depreciation

The methodology and depreciation used and applied respectively were as outlined above for transmission.

Capital Expenditure

The increase in capital expenditure from $126.8 m to $160.5 m in YE 2006 is due to revised forecasts being available based on actual expenditure for the year until the end of April 2006.

Section 6.2 of the revised proposed AA acknowledges that the capital expenditure in YE 2006 is a forecast and details the methodology that Western Power will utilise to ensure Western Power is economically neutral for any forecast error.

Corporate Asset Allocation

As a part of the split of Western Power Corporation into four separate businesses, Western Power was gifted a number of assets that had previously not been included in the initial capital base. Detail of these assets is presented in Table 30 of the revised proposed AAI.

7.2 Assessment

We noted that there is no change in the YE 2004 closing balances taken from PricewaterhouseCoopers' valuation report and that the adjustments made to convert the amounts previously stated to real terms appeared reasonable.

We had no reason to consider Western Power's capital expenditures during the period 1 July 2004 to 30 June 2006 to have been imprudent. However, we did not consider ourselves competent to express a view on the correctness of the revised adjustments made in depreciation and net capital expenditure for YE 2005 or YE 2006 as their verification is an accounting matter.

We note that the Authority may also wish to check the correctness of inclusion of corporate assets allocated to Western Power, which are stated as $8 m each for transmission and distribution.

In all other respects, the findings and recommendations in our Final Report in respect of the valuation and its roll-forward remain unchanged.

8 Conclusions and Recommendations

8.1 Summary of Conclusions

Amended Recommendations

In summary, the findings and recommendations in our Final Report in respect of the proposed expenditures, the valuation and its roll-forward remain unchanged, apart from the following amendments:

(a) the recommended level of transmission capex is amended in accordance with section 3.3 of this report from a total, over the period, of $514.7 m to $638.7 m;

(b) the recommended level of transmission opex is amended in accordance with section 4.4 of this report from a total, over the period, of $224.4 m to $191.2 m;

(c) the recommended level of distribution capex is amended in accordance with section 5.3 of this report from a total, over the period, of $767.3 m to $873.6 m; and

(d) the recommended level of distribution opex is amended in accordance with section 6.4 of this report from a total, over the period, of $453.4 m to $582.6 m.

(e) In relation to the initial capital base, we did not consider ourselves competent to express a view on the correctness of the revised adjustments made in depreciation and net capital expenditure for the two years ending 30 June 2006 or for the inclusion of corporate assets allocated to Western Power, as their verification is an accounting matter. In all other respects, however, we were satisfied that the re-stated amounts indicated in section 7.1 were reasonable and we did not have any reason to consider Western Power's capital expenditures during the period 1 July 2004 to 30 June 2006 to have been imprudent.

General Comments

As noted previously, Western Power is in a transitional phase, restructuring itself and introducing new systems to improve service levels and reduce costs. The expenditures that we have recommended take account of that situation whilst still meeting the Code's overall requirement that expenditures do not exceed the amounts that would be made by a service provider efficiently minimising costs.

In all other respects, the findings and recommendations in our Final Report to the Authority of December 2005 remain unchanged and this report is supplementary to, and is to be read in conjunction with, that report. (For the avoidance of doubt, our email of 17 January 2006, which the Authority referred to in its draft decision, is now superseded.)

8.2 Matters for the Authority's Consideration

In concluding, we list below for the Authority's consideration the following additional matters mentioned in the text.

- The way in which the **new facilities investment test** is to be applied vis-à-vis the **capital contribution policy** is unclear. (Reference in the text: p. 13 under the heading 'Customer-Driven Investment'.)
- It is not clear that the **Neerabup transmission capex project** has been committed in accordance with the definition of commitment in the Code. If not, it should be subject to a Regulatory Test. (Reference in the text: p. 17 under the heading 'Customer-Driven Expenditure'.)
- We have included the proposed expenditure on **generation tariff meters** in our recommendations but the statement on which we relied may need to be corroborated; and the expenditure concerned may be recoverable through additional charges. If so, the Authority may need to consider those revenues in its calculations. (Reference in the text: p. 17 under the heading 'Generation Tariff Meter Expenditure'.)
- The cost of providing **miscellaneous network services** may also be recoverable through additional charges. If so, the Authority may need to consider those revenues in its calculations. (Reference in the text: pp. 20 and 28 under the heading 'Miscellaneous Network Services'.)
- **Customer-driven distribution capex and the accompanying contributions** may be under-stated. (Reference in the text: p. 23 under the heading 'Customer-Driven Expenditure'.)
- The **Technical Rules** are not yet final and so further changes in the estimates may be required when they are promulgated in their final form. (ibid.)
- The correctness of rolling **corporate assets** allocated to Western Power (stated as $8 m each for transmission and distribution) into the capital base should be confirmed. (Reference in the text: p. 33 section 7.2.)

8.3 Disclaimer

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to it. No responsibility is accepted if full disclosure has not been made. No responsibility is accepted for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied directly or indirectly.

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Appendix A: List of Personnel Met

Meetings or discussions were held with the following personnel:

The Authority

Mr Peter Kolf, General Manager
Mr Robert Pullella, Executive Director, Industry Policy
Ms Alison Ovenden, Acting Manager, Projects
Dr Ray Challen, Consultant.

Western Power

Mr Peter Mattner, Manager, Regulation, Pricing and Access Development
Mr Syd McDowell, Manager, Network Performance
Mr Bill Bignell, Transmission Capacity Planning Manager
Mr Neil Chivers, Access Services Manager
Ms Vanessa Ryan, Senior Business Consultant
Mr Steve Williams, Information Strategy Manager