Economic Regulation Authority
Western Australia

Review of Western Power's Expenditures for Second Access Arrangement

Final Report

May 2009

Wilson Cook & Co
Engineering and Management Consultants
Advisers and Valuers

Reply to: Auckland Office
Our ref: 0808
Email: info@wilsoncook.co.nz

18 May, 2009

Mr Robert Pullella and Ms Sarah Walsh
Economic Regulation Authority
Level 6, Governor Stirling Tower
197 St Georges Terrace
PERTH WA 6000

Dear Mr Pullella and Ms Walsh,

REVIEW OF WESTERN POWER'S EXPENDITURES FOR SECOND ACCESS ARRANGEMENT (FINAL REPORT)

In response to your instructions, we have pleasure in presenting our assessment of Western Power's proposed capital and operating expenditure for its second access arrangement covering the years FY 2010 to FY 2012.

In summary, the key issues and conclusions from our review are as follows.

(a) Western Power will over-spend in distribution opex and in transmission and distribution capex in the present period against the approved levels. The principal reasons given are high rates of growth in load and connections, the cost increases experienced in materials and labour and the need to increase distribution maintenance to address safety and performance issues.

(b) Western Power's proposed capex and opex in the next period (from 1 July 2010 to 30 June 2012) are both substantially above the levels in the present period. The reasons for the increases (which were proposed before the potential impact of the current world-wide economic downturn became fully evident) are a combination of the continued uplift in labour rates and the cost of materials, continued strong growth in demand, the poor condition and performance of some of the network assets, the need to achieve greater compliance with standards and regulations and the need to eliminate the continuing backlogs of work.

(c) The increase in transmission capex is driven by major reinforcement projects that in most cases are overdue. The increase in distribution capex is driven by a step-up in asset replacement and compliance expenditure as well as by continued growth. We conclude that the capex proposed for the next period is reasonable in scope and efficiency, except for an adjustment to remove a proposed “risk allowance factor”. We do not consider its inclusion in the estimates to be justified.

(d) Insufficient information is available to determine the **efficiency** of capex in the **present period** in terms of its **cost-effectiveness**, although we conclude that the work undertaken was **prudent** and that it was also **efficient in terms of planning and prioritisation –** in essence, efficient in terms of the scope and timing of the capital expenditure made.

(e) The increase in opex in the next period is driven by a large increase in preventive maintenance, which has not been carried out to the required level in recent years. This should be offset to some degree over time by reduced requirements for corrective maintenance.

(f) Western Power’s ability to gear up to deliver its maintenance strategy and capital works will be crucial if its projections are to be met. In the case of distribution maintenance, we doubt its ability to achieve its projections in the first year of the next period. In addition, we consider that it has not adequately factored in offsetting improvements when it calculated its corrective maintenance expenditure. We conclude that some adjustment is needed to bring opex to a more reasonable level on these accounts. Details of the adjustments are given in the main text at the conclusion of sections 8 and 9.

(g) No adjustment is considered necessary in transmission capex on the ground of deliverability, as special (alliance) contracting arrangements have been made. The most probable cause of delay in that area is thought to be hold-ups in its capital expenditure approvals. However, that is not a matter in respect of which we consider it appropriate to propose an adjustment, although it remains a risk.

Our opinion is summarised in section 10 of the report, along with a note on matters that we would like to bring to your attention.

In conclusion, we acknowledge with thanks the assistance and cooperation of the Authority and Western Power in the preparation of this report.

Yours faithfully,

Wilson Cook & Co Limited

Wilson Cook & Co.

Encl.

Review of Western Power’s Expenditures for Second Access Arrangement

Final Report

Prepared for the Economic Regulation Authority

By Wilson Cook & Co Limited

Enquiries to Mr J W Wilson

Our reference 0808

May 2009

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Disclosure

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 us. No responsibility is accepted if full disclosure has not been made. We do not accept responsibility for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied.

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1 Introduction

1.1 Appointment and Terms of Reference

In September 2008, 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 technical advice in relation to Western Power's forecast capital and operating expenditure (capex and opex) for the three-year regulatory period FY 2010-2012 (referred to in this report as "the next period") under its proposed second access arrangement. [2]

We were also to review and provide advice in relation to Western Power's capital expenditure in the present regulatory period FY 2007-2009 (referred to in this report as "the present period").

Our advice was intended to assist the Authority in its review of Western Power's proposed revisions to its access arrangement for the South-West Interconnected Network (SWIN), submitted to the Authority at the beginning of October 2008. [3]

The terms of reference for the services are given in appendix A.

1.2 Objective of the Review

The principal objective of the review in relation to forecast expenditure (non-capital costs and new facilities investment) was to provide advice as to whether the forecasts are consistent with the specific requirements of the Code (sections 6.40 to 6.42 and 6.49 to 6.51). [4] We noted the wording of the Code, particularly section 6.52(a) which refers to a service provider "efficiently minimising costs". We noted also that section 1.3 of the Code defines that phrase (efficiently minimising costs) and we discuss our interpretation of it and other related terms in section 2.4 of this report under the heading "Prudence and Efficiency".

In the case of the capital base, our review was to provide advice as to whether Western Power's proposed revisions to determine its capital base for the second access arrangement period were consistent with the requirements of section 6.48 of the Code. The section states "…the capital base for a covered network must be determined in a manner which is consistent with the Code objective". [5] [6]

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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 References to Western Power throughout this report are to the Electricity Networks Corporation trading as Western Power.

3 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".

4 *Electricity networks access code, 2004* and its amendments (the Code).

5 A note to this section states, "A number of options are available in relation to the determination of the capital base at the start of an access arrangement period, including: rolling forward the capital base from the previous access arrangement period applying benchmark indexation such as the consumer price index or an asset specific index, plus new facilities investment incurred during the previous access arrangement period, less depreciation and redundant capital etc; and valuation or revaluation of the capital base using an appropriate methodology such as the Depreciated Optimised Replacement Cost or Optimised Deprival Value methodology".

6 Section 2.1 of the Code 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".

1.3 Scope of Work

We noted in relation to capex and opex that we were to:

- review and provide advice on the reasonableness and appropriateness of, or recommend alternatives to, the components and values in Western Power's capex and opex;
- review any relevant consultants' reports commissioned by Western Power and provide advice as appropriate;
- review any variations in capex and opex from historical levels or industry benchmark data; and
- investigate and provide advice on any discrepancies, and provide recommendations, where appropriate.

We noted in relation to the capital base that we were to:

- review and comment on the reasonableness and appropriateness of any assumptions made by Western Power in its calculations;
- review and comment on Western Power's asset registers, including the levels of accuracy of actual and forecast costs, given historical and industry benchmark data; and
- identify any matters that, in our opinion, may warrant further investigation by the Authority and/or explanation from Western Power.

We confirmed with the Authority that consistency with the **technical** aspects of the Code's requirements was the matter we were to examine. In particular, in relation to section 6.52 of the Code, we were to examine the information and provide opinions relevant to the "efficiently minimising costs" test in part (a) of that section, not part (b) which deals with incremental revenue, net benefit or necessity in terms of safety, reliability or contractual obligation. [7]

We were to provide other assistance as required and to have regard to 'industry best practice', applicable legislation, precedents relevant to regulated energy infrastructure in Australia and elsewhere and the objectives of the Code.

1.4 Data Used

Unless noted otherwise, the report is based on the proposal submitted by Western Power in October 2008, supplementary information prepared by Western Power and submitted to the Authority and us and the representations made by Western Power.

1.5 Work Programme, Consultation and Reporting

Work on the assessment commenced in October 2008, following the submission of Western Power's proposal. A visit was made to Perth at the end of November to be briefed by Western Power on the matters that it wished to emphasise in its proposal, discuss in detail with its staff each of the main elements of the expenditure proposals and receive additional

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7 Part (a) of section 6.52 reads "New facilities investment satisfies the new facilities investment test if: (a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to: (i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and (ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales".

supporting information. Discussions were held with the Authority on the background to the work and the outputs required. Most of the information requested during our visit was provided by Western Power during December.

Work recommenced on the review in late January after the Christmas break with a presentation from Western Power on its proposed contracting alliances and the supply of further information in response to our requests. On 30 January, the Authority advised Western Power that insufficient information had been provided by Western Power in support of its capex in the present period and that clarifications of its capex in the next period were required. The Authority issued a formal request for this information, which was followed on 8 February by a supplementary list of additional information required for our review. The supplementary list was sent to Western Power on or round 17 February and Western Power provided a comprehensive reply (that we received on 30 March) to all matters in the supplementary list other than the new facilities investment test results requested in respect of its capex in the present period.

Following receipt and analysis of this information, but (on the instructions of the Authority on 9 April) without seeking further clarifications as the time within which we were to report had already passed, we concluded our report and submitted it to the Authority on 18 May 2009 as a draft for review and confirmation that it addressed our terms of reference. Various clarifications were added and minor corrections were made in response to the comments received from the Authority but our conclusions were not affected. Subsequently, the report was sent by the Authority to Western Power for confirmation that it did not contain factual errors or information that is confidential to Western Power and that the representations attributed to Western Power were accurate. Minor corrections were made, based on the responses from Western Power reported to us by the Authority, and the final report was tabled on 14 July 2009 for use by the Authority.

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, Mr Chris Collie-Holmes, Mr Pat Hyland and Mr Bernard Ivory, all of Wilson Cook & Co.

A list of personnel met during the assessment is given in appendix B.

1.6 This Report

This report summarises the work carried out, our general observations and conclusions. It is presented in 10 sections:

Section 1	Introduction (this section)
Section 2	Background and Approach to the Review
Section 3	Business Profile and Network Features
Section 4	Expenditure Projections and Related Issues
Section 5	Transmission Capex
Section 6	Distribution Capex
Section 7	Business Support Capex and Opex
Section 8	Transmission Opex
Section 9	Distribution Opex
Section 10	Conclusions and Recommendations.

1.7 Abbreviations, Tables and Currency Units

The following abbreviations and terms are used in the text and have the meanings stated:

AAI	Access Arrangement Information
ERIU	Electricity Reform Implementation Unit
IMO	Independent Market Operator
MIMS	Maintenance Information Management System
PB	Parsons Brinckerhoff
RPIP	Rural Power Improvement Programme
SKM	Sinclair Knight Merz
SWIN	South West Interconnected Network
SUPP	State Underground Power Programme
the Act	The Electricity Industry Act, 2004
the Authority	The Economic Regulation Authority
the Code	The Electricity Networks Access Code, 2004
the Corporation	Western Power Corporation
the Government	The Government of the State of Western Australia
the State	The State of Western Australia
Western Power	Western Power Corporation

'Period' means regulatory period unless the context requires otherwise, the present period being that covered by the first access arrangement and the next period being that covered by the proposed second access arrangement.

Other abbreviations – capex, opex, GIS, GWh, HV, IT, LV, MVA, ODV, SCADA and the like – have their common meanings.

"NA" in the tables means 'not applicable' or 'not available' as the context requires; and "c." means *circa* or 'around'.

Sums have generally been rounded and tables may not add for that reason. FY 2008 means the financial year ending 30 June 2008, etc.

Unless noted otherwise, all sums are stated in real 2009 dollars except for the comparison of expenditure in the present period, where nominal dollars are used.

1.8 Probity

The Authority's staff provided guidance in respect of our terms of reference and assisted us with our work. We considered their advice and requests but are satisfied that none influenced our report or its conclusions inappropriately.

1.9 Acknowledgements

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

2 Background and Approach to the Review

2.1 Background

Western Power's south-west interconnected network (SWIN) is subject to economic regulation by the Authority in accordance with the Code. Western Power submitted proposed revisions to its present (first) access arrangement to the Authority on 1 October 2008 in accordance with the Code. After assessing the compliance of the proposed revisions to the access arrangement with the requirements of the Code and undertaking public consultation, the Authority is to issue a decision on the proposal. This is the second access arrangement proposal from Western Power to be considered by the Authority, the first having been lodged and considered in 2005 with a revision to it being lodged and considered in 2006.

2.2 Documents and Data Received

Documents and data received from the Authority included Western Power's *'Proposed revisions to the access arrangement for the south west network owned by Western Power'* and *'Revised access arrangement information for the network of the south west interconnected system'*, relevant material available publicly on the Authority's web site including submissions in relation to the access arrangement received in December 2008 from various parties including Western Power and the Department of Treasury and Finance; relevant information on Western Power's expenditure and copies of correspondence relating to the matters under review by us.

Documents and data requested and received directly from Western Power or through the Authority included relevant published reports, responses to our questions, presentations made at our meetings with Western Power and copies of other relevant documentation, some or all of which was considered confidential. The following list indicates the type of material received.

- (a) Statements of corporate intent and selected annual reports.
- (b) Organisation charts showing staff complements and functional responsibilities.
- (c) Asset management plans.
- (d) Network planning reports and project and expenditure assessments.
- (e) Relevant policies and procedures.
- (f) Miscellaneous data including, for selected cases or years:
  - (i) past and proposed expenditure broken down by function;
  - (ii) supplementary descriptions of past and proposed expenditure items and the reasons for them;
  - (iii) information on indirect costs (overheads) assigned to the network businesses units;
  - (iv) information on the cost and nature of services or facilities (other than those covered by overheads) provided to the network businesses units;
  - (v) information on the method of prioritisation of capital works;
  - (vi) network planning criteria;
  - (vii) selected information on the cost of major projects or programmes included in the capex and opex estimates;
  - (viii) details of the methodologies used to establish the estimates and in some cases copies of the costing or estimating models used;

(ix) reconciliations of expenditure tables;
(x) descriptions of the cost escalation methodologies applied; and

(g) general data including customer numbers, network line diagrams, load and circuit reports, substation peak load reports, forecast demand, energy throughput, electrical losses, network performance statistics and asset age profiles.

We did not consider it necessary to request detailed asset condition information or power planning analyses for our review, although we did request and receive selected summaries of asset condition data and engineering assessments to evaluate the expenditure programmes.

We also received, through Western Power, recent copies of the '*Statement of Opportunities*' published by the Independent Market Operator.

2.3 Adequacy of Information Available

Western Power did not refuse us any information that we requested and that was considered by us to be material to our assessment. However, it did not provide in its proposal and was not able to provide subsequently, in the time available, the new facilities investment test information asked of it by the Authority or an explanation of the variances between the approved and actual levels of expenditure in the present period requested by us. Both of these items were considered necessary by us for our assessment of Western Power's proposed addition of its capex in the present period to its capital base.

Specifically, we asked that in relation to the major programmes and projects proposed for the present period, it should provide a reconciliation of actual *vs.* proposed expenditure in terms of expenditure and physical implementation in respect of each of them, e.g. state of completion, nature of completed work *vs.* the estimates, results of the work such as in terms of reduced level of transformer utilisation.

At the time of writing this report, the only information supplied in response to this request was a list of projects with actual expenditure for the first two years of the present period and forecast expenditure for the last year of the present period. The list was supplied without accompanying explanation sufficient to address our request. [8]

Other than in that respect – and whilst there were some discrepancies that remained unexplained and some unanswered questions at the time we concluded our work – we considered that we had sufficient information for our assessment of expenditure in the next period. [9]

2.4 Our Approach to the Review

We based our assessment of Western Power's proposed expenditure on the Corporation's proposed access arrangement and access arrangement information, the supporting documents and the submissions and responses made subsequently to the Authority and to us.

We followed the conventional approach in reviews of this type including, to the extent needed for the purpose of our assessment:

- the identification of key expenditure drivers;
- confirmation of Western Power's policies for the capitalisation of expenditure;

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[8] We discuss this matter further in section 4.3.

[9] The material discrepancies and unanswered questions are referred to in the text in sections 5 to 9.

- a review of the adequacy of the information available to Western Power on its assets;
- a review of the adequacy of Western Power's planning processes in terms of the appropriateness of planning criteria, robustness of modelling and decision-making and adequacy of documentation;
- the comparability of Western Power's activities with international practice in respect of asset provision, asset utilisation and network reliability;
- the identification of Western Power's major projects and programmes, the expected outcomes, demonstrated necessity and reasonableness of timing;
- an assessment of the individual expenditure components including the installed cost of new assets, optimality of design and construction practices, reasonableness and efficiency of the expenditure proposed for: demand-related reinforcement, new connections, asset replacement, reliability and quality improvement , environmental, safety and statutory compliance, and support facilities including SCADA and IT;
- comparison of the proposed levels of capex with past levels;
- consideration of the reasonableness and efficiency of the projected capex in total;
- consideration of the efficiency and reasonableness of the proposed opex under headings such as preventive maintenance, reactive maintenance, etc and in total;
- comparison of the proposed levels of opex with past levels;
- consideration of any new factors impinging on Western Power to the extent they have not already been assessed under the preceding points;
- review, to the extent possible, of any resource constraints that might impinge on Western Power's ability to implement its expenditure proposals fully within the period; and
- a review of comparative performance statistics publicly available in respect of other network businesses.

As is the case in other reviews of this type, we do not endorse or reject particular projects individually but seek only to satisfy ourselves of the reasonableness and efficiency of the aggregate level of expenditure required. [10]

In that context, we note that the normal objective of this type of assessment is that the reviewer should be able to:

- assess the efficiency of the network businesses' expenditure estimates and asset management policies in terms of their match with international practice,
- take into account a natural level of trade-off between capex and opex,
- be satisfied that the proposed expenditure, projects and programmes are consistent with maintaining, or where necessary varying, standards and service delivery capacity,
- form an overall strategic view of whether the businesses' proposed levels of expenditure are reasonable and efficient; that is, whether they represent efficient levels for the defined security of supply and service standards or,
- if required, be satisfied that they reflect a transitional path from the present level of expenditure to a more efficient level.

[10] Western Power should determine, itself, whether to pursue individual projects.

We thus took into account past levels of spending from the standpoint of whether it ought to influence future expenditure levels and other expert opinion on the projected expenditure or related matters that was made available to us.

Level of Preparation of Projects and Optimality of their Timing

Generally, we considered that the level of preparation of the projects and programmes we reviewed was appropriate for planning purposes, recognising that plans do not constitute, by themselves, a justification for proceeding with work until detailed studies have been prepared and the relevant criteria met. In that context, it is normal for some work to be advanced later on, for other work to be deferred, for some to be amended and for other items to be dropped altogether.

We noted that whilst particular items of expenditure might be justified, the optimality of their timing was more difficult to gauge.

Optimality of Network Designs and Reasonableness of Construction Costs

We noted the information that was provided in support of the plans, designs and construction cost estimates of the major network expenditure items proposed. We noted that, in general: the procurement of materials and equipment is bid competitively; design and installation is undertaken using Western Power's own resources or contracted resources; newly established alliance contracts will provide considerable additional resources for project implementation; the designs appeared reasonable; and the various high-level reviews of cost, undertaken by engineering advisers to Western Power, had generally found the construction costs assumed by Western Power in its proposal to be reasonable.

Whilst it was not possible to gauge accurately how effective Western Power's internal resources and processes are at the implementation of this work, we considered, on balance, and in light of our experience, that the installed cost of new assets was reasonable for the purpose of this review.

Capex-Opex "Trade-Off"

We considered at a general level whether Western Power's proposed expenditures exhibited or appeared to exhibit an appropriate trade-off between capital and operating expenditure. Whilst it was not possible to be definitive without carrying out a detailed study, we noted, as did the Corporation itself, that the level of reactive maintenance expenditure is high in relation to the expenditure on preventive maintenance, suggesting that there is insufficient preventive maintenance being carried out; and that, given the high levels of distribution system utilisation, the Corporation's augmentation of network capacity continues to lag behind the growth in demand. We noted that Western Power has proposed an increase in preventive maintenance and in capital expenditure to help redress this balance and to improve distribution network reliability. However, we also noted, as did Western Power, that the increased level of expenditure forecast for the next period would still not be sufficient to redress the current backlog.

In terms of the expenditure estimates, we noted that Western Power has incorporated a trade-off in its forecast transmission opex, resulting from the proposed asset replacement and refurbishment capex in the next period. The reduction is said to reflect the avoidance of corrective maintenance work on new assets (although they still require operational expense and preventive maintenance). The reduction has been calculated at 18% of the costs of maintaining and operating assets that have approximately half or more of their service lives remaining. This is the ratio used in the opex model to apply the opex savings. [11]

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[11] See Appendix 1 p. 109 of the *Access arrangement information*.

We believe, however, that a wider view of the trade-off should be taken by assessing the overall level of capex and opex and the interrelated impacts on the age and condition of the assets and thus on maintenance costs. We considered that the method Western Power has used to estimate its **corrective** maintenance expenditure did not take adequate account of reductions that could reasonably be expected in it from the increased replacement capex and preventive maintenance expenditure proposed. We comment further on this in sections 8.3 and 9.3 of this report.

Prudence and Efficiency

The terms of reference do not define prudence or efficiency for the purpose of the review. However, section 1.3 of the Code includes the following definitions.

- *Efficiently minimising costs*, in relation to a service provider, is defined as "the service provider incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services".
- *Reasonable and prudent person* is defined as "a person acting in good faith and in accordance with good electricity industry practice".
- *Good electricity industry practice* is defined as "the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines".

Without attempting to interpret the Code but noting the circularity of argument in relation to prudence in the second and third definitions and noting, also, the reference in the third definition to "comparable conditions and circumstances", we adopted the following approach.

We noted the objective of the review as already stated in section 1.2 of this report, with its emphasis on "efficiently minimising costs" as defined in the Code.

We noted, in a general sense, that to ensure adequacy or effectiveness, a prudent operator might undertake more work than otherwise considered necessary but to ensure efficiency it might undertake less or spend less to achieve the same result and thus a balance between the two is required.

We noted that *prudence, per se*, is a subjective quality that has connotations of exercising sound judgement especially concerning one's own interests, being careful to avoid undesired consequences, being cautious or circumspect in one's conduct, managing carefully and with economy. Prudence is often best judged by the absence of evidence suggesting a lack of it. In the case of electricity networks, imprudence might be most discernible if there was evidence of failure to invest adequately, accompanied by identified adverse consequences, and is thus best assessed retrospectively. [12]

Where we considered that there was an appropriate balance between these factors, prudence and efficiency, we have said in the text that the expenditure is "reasonable".

Where we found material instances of imprudent expenditure, an imprudent failure to make expenditure or of what appeared to be inadequate provision for future expenditure, we have identified them.

[12] Over-investment and the consequential under-utilisation of fixed assets are probably more indicative of inefficiency.

We considered *efficiency* in terms of the nature and the timing of expenditure and looked for evidence that as far as practicable the expenditure reflected optimal planning and design and competitive costs taking account of local factors, 'good electricity industry practice' and the defined security of supply and service standards of the network business concerned – in this case, Western Power.

We refer, where appropriate, to Western Power's circumstances, as good electricity industry practice requires particular circumstances to be taken into account. [13]

We interpreted *good electricity industry practice* as defined in the Code and stated above but to do so required an interpretation of the words "applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines". We interpreted them to mean the engineering, safety and environmental requirements as we understand them to apply in the electricity supply industry generally. We did not attempt to research or confirm those requirements as far as they apply to Western Power other than in a general sense as, to do so, would have required a comprehensive legal review outside our field.

Findings of Our Earlier Reviews

We took account of the findings in our expenditure reviews carried out in 2004 for the Electricity Reform Implementation Unit (ERIU) and in 2005 and 2006 for the Authority in respect of Western Power's first access arrangement and its revision but considered the information provided to us at that time to have been superseded by the information for the current review. [14]

Reasonableness of Aggregated Projections

Where possible, we reviewed Western Power's expenditure proposals from a "top-down" perspective as well as a "bottom-up" perspective. The "bottom-up" approach was made by considering the build-up of both capex and opex from projects, programmes and past expenditure levels. The "top-down" approach looked at the level of expenditure as a whole in the context of the size and nature of comparable networks and the circumstances of Western Power. [15]

As a general principle, we retained the view that whilst each individual project or programme may be justified when considered in isolation, it is still necessary that the aggregated expenditure projection be reasonable. The aggregation of estimates for individual projects and programmes without adequate consideration of their impact in total, or of cost savings in other parts of the business, generally does not lead to an efficient level of expenditure. [16]

Assessment of Proposed Additions to Capital Base

The terms of reference require, in relation to forecast expenditure (non-capital costs and new facilities investment), that we "review and provide advice as to whether the forecasts are consistent with the specific requirements of the Code, sections 6.40 to 6.42 and 6.49 to 6.51" and that we "review and provide advice as to whether Western Power's proposed revisions to determine its capital base for the second access arrangement period [are] consistent with the requirements of the Code, section 6.48". The Code requires amongst other things that only capex that meets the new facilities investment test (NFIT) can be added to the capital base.

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[13] The word used in the definition is 'comparable' but the implication is clear.

[14] Wilson Cook & Co Limited was engaged in 2004 by the Electricity Reform Implementation Unit through Energy Market Consulting Associates to assist the ERIU with its review of projected operating and capital expenditure forecasts of Western Power and was engaged in 2005 and 2006 by the Authority to review Western Power's first proposed access arrangement and its subsequent revision.

[15] "Top-down" assessments were restricted to opex.

[16] Amongst other reasons, this is because the individual components interact, or ought to do so.

We therefore needed to satisfy ourselves that, from a technical standpoint, Western Power's capex in the present period meets the first leg of the NFIT, section 6.52:

> *"New facilities investment satisfies the new facilities investment test if: (a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to: (i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and (ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales."*

The second leg of the test is focused on how the service provider justifies payment for the work and is not a matter on which we were required to offer an opinion.

In essence, the NFIT, as far as it affects our work, is little different to the normal tests of efficiency and prudence that we would apply in reviewing past and future capex put forward by a network business.

Benchmarking of Opex

In concluding our opinion, we took note of the benchmarking analyses presented by Western Power in section 2.7 of Appendix 1 of its Access Arrangement Information. However, for the reasons explained in section 9.5 of this report, we carried out our own comparison of its distribution opex with that of other businesses, both excluding its sub-transmission assets and including them. It bears re-stating that benchmarking has recognised limitations and thus, whilst broad comparisons of companies may be made of operational expenditures through benchmarking, various factors complicate the comparisons and require the exercise of considerable judgement when interpreting the results. [17]

Comparison of transmission businesses is more difficult because of the significant differences between them, particularly in load density and the transmission distances involved. We did, however, compare transmission opex on an opex per kilometre of line basis to illustrate how Western Power's current and proposed levels of expenditure compared with other transmission businesses.

Benchmarking of Capex

We did not consider it appropriate to benchmark Western Power's system capex with other companies as it is driven by company-specific factors and thus comparisons with other companies – particularly those based on denominators such as customer numbers or line kilometres – are in our view inappropriate. We considered instead that a company-specific assessment was the correct approach in regard to it. [18]

Details of Our Assessment

Details of our assessment are given in the following sections of this report.

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[17] These factors include differences in the type of network, voltage levels, growth rates, customer and load densities, asset ages and condition, load mix, geographic coverage and other factors including service targets. Additionally, some companies may fully out-source their operational and maintenance activities whilst others carry out the work in-house or use a mix of both policies. Different approaches lead to different cost structures. Other adjustments that may need to be made before drawing conclusions include: a check that the period reviewed was typical of expenditure patterns in each business; whether the same asset or expenditure categories have been included in all cases – metering, public lighting and vested assets are sometimes excluded – and whether any exchange rate or other adjustments are required before comparisons are made with off-shore businesses.

[18] We considered benchmarking non-system IT capex but as Western Power's corporate IT services are contracted from a non-regulated business unit, we did not consider that a valid comparison could be made with other entities.

2.5 Matters Not Considered

The following matters were excluded from consideration in our work or were not undertaken:

- review of forecast demand, as that was not within our terms of reference, other than to discuss the implications of the current economic "crisis" with Western Power; [19]
- review of Western Power's Technical Rules or the revisions it proposes to them for the next period, other than to the extent of checking the potential impact of the propose rule changes on the expenditure required for the period;
- review of Western Power's policies for the allocation of overheads other than to note that the changes made to the method of allocation in FY 2009 and the impact of these changes on capex and opex;
- review of Western Power's policies for the capitalisation of expenditure other than to note that the cost of replacing run-to-failure assets is expensed and that this will tend to inflate the estimates of opex;
- review or re-calculation of detailed power planning analyses;
- re-estimation of cost escalators applied by Western Power to its proposals;
- review of expenditure other than that associated with Western Power's network and the SWIN;
- any matters to do with capital contributions from connected parties;
- expenditures relating to 'system operator' activities except to the extent identified in later sections of the report;
- consideration of the possible effects of the following factors that can only be conjectured:
  - requirements for capex related to future safety issues, new statutory requirements, new Government policies or initiatives, or environmental requirements except to the extent that they have been identified by Western Power and allowed for in its proposal;
  - possible adjustments in capex stemming from the application of demand management policies other than those already reflected in Western Power's estimates;
  - any changes from current network planning or design practice;

- physical inspection of the assets;
- re-calculation of expenditure if we had reason to consider the projections inappropriate, other than in respect of proposing adjustments for the Authority's consideration;
- any matters outside our field of expertise; and
- any other matters identified elsewhere in the report as having been excluded from our work.

We did not carry out an audit of Western Power's accounts, asset register, data, expenditure, processes or any item or activity or take any action that might be considered to have constituted an audit but relied instead solely on the submissions received from Western Power and the representations made in response to our enquiries.

[19] In Western Australia, the demand forecast is prepared by the Independent Market Operator but the forecasts used in access arrangement proposals are to be consistent with them. See section 5.2.

3 Business Profile and Network Features

3.1 Business Profile

Western Power was formed through the dissolution of the State Electricity Commission of Western Australia in the electricity sector reforms of 2004 and the subsequent separation of the Western Power Corporation into four businesses in April 2006. [20] There have been no changes to Western Power's composition since that time. It owns and operates transmission and distribution network assets in the south-west interconnected network.

Organisationally, the business is structured in seven operational divisions and employs around 2,200 full-time-equivalent personnel, including contract staff.

It procures material and equipment from outside suppliers but to date has mostly used its own resources, supplemented by contractors, for planning, designing, installing, maintaining and operating its network. However, in April 2008, it announced "alliance" agreements with Downer EDI Engineering, Tenix Alliance and Transfield Services to provide more resources for the implementation of its work programme.

It undertakes two State-funded programmes, the State Underground Power Programme (SUPP) and the Rural Power Improvement Programme (RPIP). [21]

3.2 Network Features

The network features most relevant to our work are as follows.[22]

(a) The network is located in the South West of the State and extends generally between Kalbarri, Albany and Kalgoorlie.
(b) The transmission assets include 23 bulk transmission substations, 170 zone substations, around 7,000 km of overhead line and ancillary assets and operates at 330 kV, 220 kV, 132 kV and 66 kV.
(c) The distribution assets include around 69,000 km of high voltage distribution mains operating at voltages of 33 kV or lower, 21,200 km of low voltage mains, an installed distribution transformer capacity of 6,218 MVA, around 213,000 street lights and other ancillary assets.
(d) The network supplies electricity to around 994,200 customers of whom 21 take supply at the transmission level, 369 take supply at HV and the remainder take supply at LV. [23]
(e) Designs at each voltage level appear to be conventional.
(f) The physical condition of the assets is assumed to be commensurate with age.

The key network statistics are summarised in Table 3.1.

[20] The other three businesses are Synergy, Horizon Power and Verve Energy.

[21] The SUPP has been in operation since 1996 and is focussed on the conversion of overhead power supplies to homes and businesses in older urban areas to underground supply. Western Power contributes 25% of its funding. The programme is to continue through the next period. The RPIP commenced in May 2004 and is aimed at improving rural electricity supplies. It is partially funded by the State Government. It was to terminate in FY 2008 but Western Power anticipates funding will continue into the next period.

[22] A description of the network can be found in the company's documents.

[23] The data cited is at 30 June 2008.

Table 3.1: Key Network Statistics

Bulk transmission substations	23
Zone substations	170
Transmission system length (km)	c. 7,000
HV distribution system length (km)	c. 69,000
LV distribution system length (km)	c. 21,000
Distribution poles a/	c. 724,000
Distribution substations	c. 11,400
Distribution transformers	c. 59,000
Distribution transformer capacity (MVA)	c. 6,000
Street lights	c. 213,000
Total customers (meters)	c. 994,000
Peak demand (summer) (MW)	3,420

Source: Western Power Access Arrangement Information and subsequent clarifications.
a/ Comprised of around 619,000 wooden, 12,000 concrete, 89,000 steel, 1,000 reinforced and 1,500 poles of unknown type.

Age of the Assets

The expected and average remaining lives of each of Western Power's major asset categories, as estimated by Western Power, are shown in Table 3.2.

Western Power advised us that the average remaining life of its distribution assets, weighted by replacement cost, is 68%. [24] On that basis, high levels of replacement expenditure on the distribution network are not to be anticipated,[25] although we review the replacement requirements of specific asset categories in section 6.4 of this report, paying particular attention to wood pole replacements as they make up around 52% of the distribution replacement capex forecast for the next period. Table 3.2 also suggests that the transmission network assets are not overly aged and so, again, high levels of replacement expenditure are not to be anticipated.

(Although the point is not material to our findings, it was not clear whether the lack of provision of the requested age profile arose from a misunderstanding or whether the data was not readily available and we were not able to clarify the point before reporting for the reason given in section 1.5. In our 2005 review report, for example, we noted, "The availability of accurate information within Western Power in respect of its assets is discussed in its asset management plans. The Corporation acknowledges a lack of full information on age and condition, particularly in relation to its distribution assets. The distribution asset management plan acknowledges, for example, that around 70% of equipment in the asset records is without a known installation date. We noted that ages had been assigned to these assets, based on the age of associated equipment, particularly meters, as discussed in section 3 of the report." To some extent, this still appears to be the case.)

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[24] The average remaining life of the transmission assets was not stated. Age profiles for the transmission and distribution networks, each as a whole, were requested but not provided at the time of reporting. In response to our request for the age profiles, Western Power provided information in the form of forecast expenditure from which an age profile was partially deducible for distribution assets (where costs had not been "spread") but only for assets of less than 51 years of age. For transmission assets, figure 5.9 in Appendix 1 to the *Access arrangement information* provided an overall age profile, showing few assets older than 50 years but the meaning of the term "volume" in that figure was not clarified, making it difficult for us to interpret the information.

[25] Based on comparison with other networks but noting that the disposition of the asset age profile has a strong influence that we were unable to analyse fully, because of the lack of this information.

Table 3.2: Average Remaining Lives of Selected Asset Categories

Asset Category	Expected Life (yrs)	Avg Remaining Life (yrs)
Transmission		
Circuit Breakers a/	40	18
Power Transformers a/	50	24
Surge Arrestors a/	30	11
Disconnectors a/	50	24
Voltage Transformers a/	40	19
Current Transformers a/	40	19
Earth Switches a/	45	31
Poles/Towers b/	55	30
Overhead Lines c/	f/	60
Underground Cables d/	f/	35
Distribution e/		
HV OH Disconnectors	50	19
Pole Top Switch Disconnectors	35	4
Switch Disconnectors	50	19
Drop Out Fuses	35	4
Distribution Transformers	45	14
Fuse Switches	50	19
HV Cable Pole Terminations	50	19
LV Distribution Frames	50	19
Metering Units	35	4
Wood Poles g/	50	19
Substations	50	19
Overhead Carriers	55	24
Underground Carriers	65	34

a/ Source: table 3.1 of transmission asset management plan.
b/ Source: table 3.14 ibid and email from Western Power.
c/ Source: figure 3.11 ibid.
d/ Source: figure 3.14 ibid.
e/ Source: table 10 of distribution asset management plan.
f/ Not specified.
g/ Email from Western Power.

Reliability (Transmission)

Transmission reliability, measured in system minutes interrupted is shown in Table 3.3. The table shows variable performance from year to year but variations are common in transmission networks generally, as low numbers of events of variable consequence are involved. The level of reliability appears normal for a network of the type involved.

Table 3.3: Transmission Network Reliability

Year	FY2005	FY2006	FY2007	FY2008
System Minutes Interrupted /a	7.3	6.1	15.6	10.4

Source: Access Arrangement Information.
a/ All SWIN transmission, including sub-transmission.

Western Power proposes service targets of 9.3 minutes for its meshed transmission network and 1.4 minutes for its radial transmission network for the next period, derived from the averaged actual performance over the three years FY 2006 to FY 2008. [26]

[26] We note the difficulty of setting a future target based on the average of a relatively short history (three years) where it is difficult to properly identify or compensate "outlier" years that may overly weight the calculation of the new target. The apparent high value for the system minutes interrupted in FY 2007 is a case in point.

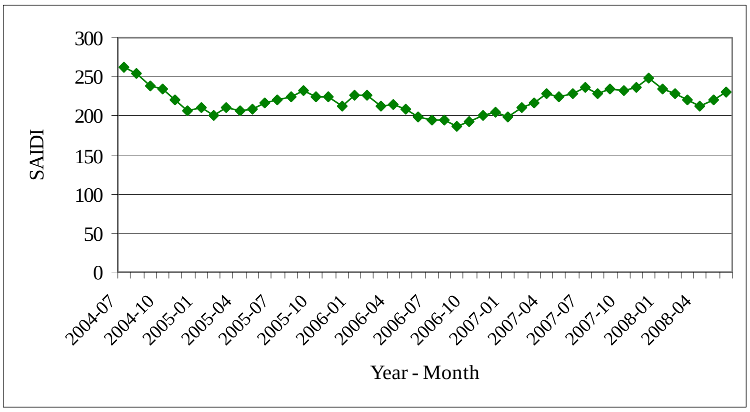
Reliability (Distribution)

The distribution network reliability trend in terms of SAIDI is shown in Figure 3.1 from 2004 to 2008. The figure shows a relatively consistent level of SAIDI performance since June 2004, although not an improving one.

In the present period, up to and including FY 2008, Western Power achieved fifteen of its twenty reliability targets. [27]

We note that this has occurred in spite of a rising trend in network fault rates and is probably due to Western Power focusing its recent reliability performance improvements at reducing customer impacts rather than the incidence of faults. [28]

Figure 3.1: Distribution System SAIDI (Rolling 12-Month Average)



Source: Western Power fault data. Excludes single customer outages, major event days, planned outages and outages caused by generation, transmission and customer equipment.

Fault Rates (Distribution)

Distribution network performance in terms of fault rates per circuit-km p.a. for Western Power's high voltage distribution mains is shown in Figure 3.2. [29] [30] [31] The figure shows (within the limits of such analysis) that Western Power's fault rates for both underground and overhead circuits compares well to New Zealand, UK and NSW DNSPs.

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[27] The reliability of the distribution network against targets set in terns of SAIDI and SAIFI for FY 2007 and FY 2008 is given in section 6.3.1 of the *Access arrangement information* Part A, from which we note that Western Power met the AA1 SAIFI targets in all categories of feeder in both years except long rural in 2008, and all SAIDI targets except CBD in FY 2007 and FY 2008, Long Rural in FY 2008 and SWIN total in FY 2008.

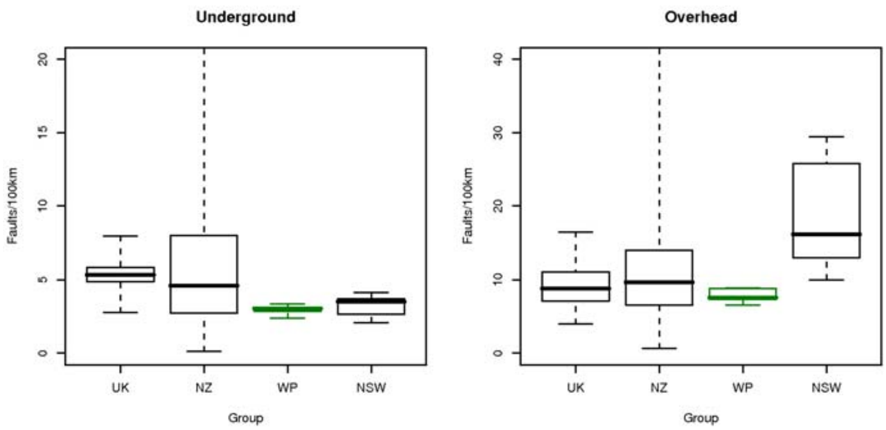
[28] Source: confidential Western Power presentation to the ERA and Wilson Cook of 24 November 2008.

[29] Sources: published data from the Office of Electricity and Gas Markets in the UK for the period 2002 to 2006; published data in respect of New Zealand lines businesses for 11 kV distribution circuits for the period 1998 to 2007 (may include 22 kV and 6.6 kV distribution circuits); and published data from the NSW regulatory reviews just concluded. The boxes show the upper and lower quartiles about the marked median value. The wide range of the data in the New Zealand case reflects the large number of companies involved (around 30) compared with the small number of companies in the UK and NSW.

[30] The statistics are for faults from all causes.

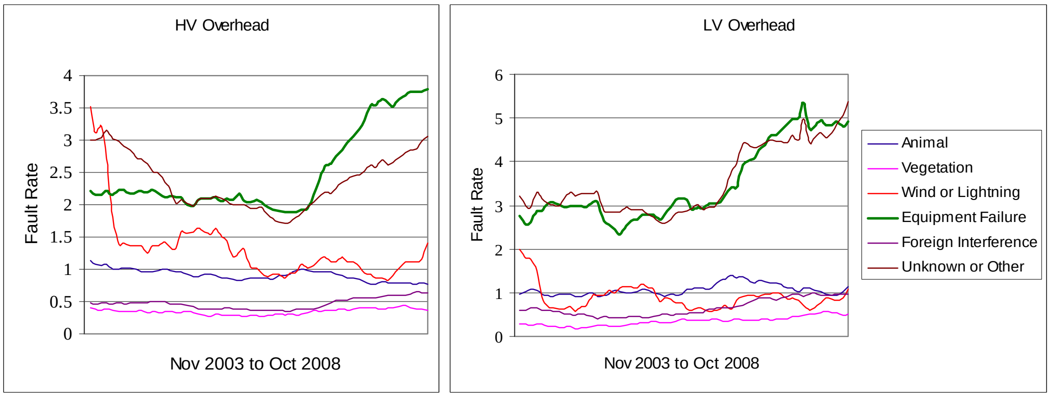
[31] We prefer the analysis of fault rates when considering the robustness of replacement expenditure projections, as they are more indicative of condition than customer performance indices such as SAIDI, which are affected by other factors and disguised to a degree by the removal of adverse weather events, the withstanding of which are a normal requirement of networks. (It is admitted that fault rates are also influenced by factors other than condition, e.g. by vegetation management and motor vehicle accidents, but in respect of storm damage they do reflect the robustness of the circuits and implicitly their general condition.)

Figure 3.2: HV Distribution Fault Rates (in Comparison with Other DNSPs)



The total fault rate appears to be comparable to other networks and is in keeping with the observation that the distribution network has a relatively young average age, as discussed above. However, the trend in fault rates, illustrated in Figure 3.3, reveals a rising trend for equipment failure faults in the overhead networks that supports Western Power's stated plan to increase preventive maintenance and undertake targeted replacement programmes that will address problem areas.

Figure 3.3: Trend in Distribution Fault Rates



New Reliability Target and Measurement Method

For the next period, Western Power proposes that its reliability performance measures be calculated excluding major event days, as defined in IEEE standard 1366. [32] That is a desirable change, as most jurisdictions remove outlier events from reliability performance measures, although the definitions of extreme event vary. For the next period, Western Power proposes a 29-minute staged improvement in SAIDI compared to its FY 2009 actual performance, for which it calculates it has a 90% probability of achievement under the (constrained) expenditure proposals for the next period. [33]

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[32] As applied by the Steering Committee for National Regulatory Reporting Requirements.

[33] Calculated with major event days removed as per IEEE 1366. The change in measurement method will make comparison of future reliability targets with past targets difficult but is desirable.

4 Expenditure Projections and Related Issues

4.1 Western Power's Expenditure Projections

Actual or forecast expenditure in the present period (FY 2007 to FY 2009) and forecasts of expenditure in the next period (FY 2010 to FY 2012) are summarised in Table 4.1. In total, expenditure is projected to increase by $2,467 m or 69% from the present period to the next with the largest rise in percentage terms and in dollars being in transmission capex.

Table 4.1: Summary of Actual and Forecast Expenditure ($2009 m)

	Present Period (AA1)				Next Period (AA2)				Difference	
YE 30 June	2007	2008	2009	Total	2010	2011	2012	Total		
Transmission capex	307	317	444	**1,068**	730	870	594	**2,194**	1,126	+ 105%
Distribution capex	448	481	583	**1,512**	708	759	823	**2,290**	777	+ 51%
Transmission opex	75	76	75	**225**	101	106	113	**320**	94	+ 42%
Distribution opex	255	260	263	**777**	394	416	436	**1,247**	469	+ 60%
	1,085	**1,133**	**1,364**	**3,582**	**1,933**	**2,151**	**1,966**	**6,050**	2,467	**+ 69%**

Source: Western Power. Figures include estimating risk allowance and business support expenditure including IT.

Unless noted otherwise, the expenditure summarised in Table 4.1 and throughout this report is gross expenditure before the deduction of capital contributions from connected parties. [34]

It includes Western Power's business support costs (including IT) and, in the case of capex, an "estimating risk factor", as shown in Table 4.2.

Table 4.2: Estimating Risk Factor and Business Support Costs ($2009 m)

Capex:	
Estimating risk factor – transmission	73
Estimating risk factor – distribution	73
	145
Business support costs – transmission	49
Business support costs – distribution	144
	193
Opex:	
Business support costs – transmission	84
Business support costs – distribution	236
	330

Source: Western Power.

Basis of the Projections

Western Power states that the expenditure summarised above excludes expenditure on smart meters, advanced metering infrastructure (AMI) and on around $1,100 m of "lower probability" customer-driven transmission projects and strategic land purchases. The potential cost of changes in standards and policies – see section 3.10 of Appendix 1 to the Access Arrangement Information – is also excluded.

[34] We have not considered any matters to do with the magnitude of capital contributions as that is a financing matter, not an expenditure matter. Nor have we considered the justification or fairness of any particular contributions or the contributions in general.

Western Power states that its primary objectives in the next period are to move steadily toward full compliance with safety, environmental and other statutory and regulatory obligations and to improve its service to customers in terms of the timeliness of new connections and the reliability and quality of supply.

It states that its primary drivers of increased expenditure from the present period are the strong cost uplift in labour rates and the cost of materials, continued strong growth in demand, the poor condition and performance of some of its assets and the need to achieve greater compliance with standards and regulations and to eliminate the continuing backlogs of work.

It states that it has adopted a two-step process in preparing its expenditure forecasts: determination of the expenditure required without considering deliverability constraints, followed by the determination of a 'resource-capable' works programme.

It states that the 'resource capable' works programme amounts to 88% of the 'unconstrained' programme and that the extent of constraint varies across the expenditure categories.

It states that in its view, the works programme in the present period has been highly constrained due principally to a lack of resources to deliver the unconstrained programme. As a result, necessary asset condition work could not be done, increasing the pressure on expenditure requirements in the next period.

It states that a significant effort has been applied to build up its resources throughout the present period for the next.

The proposed expenditure is assessed in the following sections of the report, along with Western Power's capex in the present period. However, before proceeding to the assessment, we note the following issues that arose during our review.

4.2 Budgeting and Reporting Issues in Present Period

Background

We noted from board papers provided to us by Western Power in January 2009 that Western Power's board and management were concerned, in 2007, about the forecast distribution maintenance cost overspending that was arising at that time. Inadequate management information was identified as a root cause of inadequate budget provisions, with a lack of full knowledge of the state of the network assets being a key factor. [35]

We noted from the board paper that in light of "that example of poor budgetary control and other examples over preceding months", the board and management had initiated a far-reaching programme of improvement in the Corporation's knowledge of the state of its network assets. Taking a broader perspective, the board had also asked the management to identify all the major issues affecting the Corporation's ability to establish appropriate budgets and to manage work and expenditure accordingly. These issues included a wide range of matters that we too would have expected an efficiently managed utility to attend to. [36]

The board and management recognised that the lack of reliable information had been a significant contributing factor in its submission for the first access arrangement being

[35] A lack of information on the network assets and their condition had been recognised and reported by Western Power at the time of our 2005 review and was noted in our report that year.

[36] E.g., a lack of detailed network condition information, detailed network performance information, consistent risk evaluation methods, reliable cost information, a consequential lack of definition of the scope of work required, etc.

"inadequate…in terms of operating expenditure in particular" and in consequential problems encountered in managing the expenditure in accordance with the estimate.

The board paper suggested that significant improvement in Western Power's knowledge of the state of its network assets would not be achieved until late 2008 at best given the work programme it faced, although significant improvement in most other aspects of managing the works programme would be achieved by mid-to-late 2007.

Of the issues identified, the paper said the following were the most critical in gaining control over network budget expenditure: network condition information, network performance information, work force capacity, and reliable cost information (and reduced actual costs).

A consultant, Tellis Chase, was engaged to help compare Western Power's approach to cost estimation with best business practice. Tellis Chase's confidential final report, which was presented in September 2007, recognised the considerable effort made by Western Power to improve its cost estimating performance but said that performance was still mixed. It identified various shortcomings and drew similar conclusions to those reported in the board paper discussed above, making recommendations to address the issues, the majority of which Western Power accepted and is implementing.

The Issue

The issue that arose in relation to our work was whether the budgeting and reporting issues just discussed implied inefficiency in **investment** during the present period or the next and we discuss that issue now.

Implications for Our Review of Capex in Present Period

Initially, we were concerned that the budgeting and reporting issues just discussed could suggest inefficiency in investment in the present period and the Authority questioned us on the same point. However, having considered the matter, we note the following points.

- First: whilst the business's recognised issues in cost estimation (budgeting) and reporting up to FY 2008 or possibly beyond admit a degree of weakness, the issue appears to be a **weakness principally in financial control**. That is a **different matter** from weaknesses in the planning, scoping or execution of work carried out.
- Second: **it does not follow automatically** from the recognised issues that the business's capital investment was inefficient, although that possibility exists.
- Third, we have no means of proving, disproving or quantifying any lack of efficiency that may exist in the business's capital investment in the present period as a result of the weaknesses in budgeting and financial control.

We conclude, therefore, that the budgetary and reporting issues just discussed **do not of themselves constitute evidence of inefficient investment in the present period**.

For the avoidance of doubt, we repeat that we refer here **only to the potential implications of the budgeting and reporting issues**, not to any other aspect of the efficiency of Western Power's capital investment planning or execution in the present period or the next. Those other aspects (e.g. Western Power's planning, expenditure prioritisation and project execution methods) are discussed in sections 5 to 7 of this report.

Implications for Review of Expenditure in Next Period

We then considered the implications of the budgetary and reporting issues in relation to expenditure in the next period.

In doing so, we note that a fundamental change has clearly been initiated in Western Power's approach to cost estimation and that this is confirmed in its board papers, which note that "Western Power has a very comprehensive set of improvement initiatives under way to improve its network expenditure performance; the initiatives have been prioritised and good progress is being made…"

We understand from the documents available to us that the new cost estimating processes just discussed were applied, first, to the preparation of cost estimates for Western Power's access arrangement proposal for the next period. That suggests that the shortcomings reported in cost estimating up to and including the present period ought not to be considered to extend automatically to the estimates for the next period, although whether the improvements were in full effect in time for the submission of the second access arrangement proposal in October 2008 remains a question, as plans for the major transmission works in particular were still being developed and refined. [37]

Of importance (given the stated issues with budgeting and reporting in the present period), we noted from Western Power's responses of March 2009 that a considerable degree of refinement had taken place in its cost estimating and planning for major transmission works in the next period. For example, we received copies of independent assessments of the cost of the 330 kV line to Geraldton and the related works – the biggest investment item in the capital expenditure programme – that demonstrated a thorough approach to cost estimating and preparation for this major work and that endorsed its cost estimates. That material was sufficient to satisfy us that the revised estimates and arrangements for the work were robust in the sense of the establishment of need, the prudence of the scope of work, the efficient allocation of resources including capital, and the efficiency of timing leading to the overall efficient minimisation of cost.

An assurance was received from Western Power at the same time that the same processes were being applied to the other major capital expenditure works in its transmission programme for the next period, allowing us to conclude that the sample of projects examined was representative of the reasonableness of other capital expenditure in this category.

This information addressed our main concerns in relation to the estimates for major transmission works in particular in the next period, although we discuss the justification for that work further in section 5 of this report.

Given the improvements in cost estimating just discussed, we formed the view that the budgetary and reporting issues discussed above **were more applicable to the present period than the next** and we took account of that when concluding our reviews of transmission and distribution capital expenditure in the next period in sections 5 and 6 of this report.

4.3 Lack of Information to Support Additions to Capital Base

The Issue

We have already noted in section 2.3 of this report that Western Power did not provide in its proposal, and was not able to provide subsequently in the time available, the new facilities investment test information asked of it by the Authority or an explanation of the variances between the approved and actual levels of expenditure in the present period requested by us.

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[37] For example, Table 5.3 of Appendix 1 of the *Access arrangement information* submitted in October 2008 reports an estimated cost of $360 m in year 2009 dollars for the North Country project. However, later documents, received by us in Western Power's confidential March responses to our questions, indicate a revised estimate of $597 m in year 2009 dollars. The latter excludes capitalised interest, foreign exchange risk and commodity price variation risk, as may have the earlier, superseded, estimate.

Both of these items were considered necessary by us for our assessment of Western Power's proposed addition of its capex in the present period to its capital base. [38]

Specifically, as noted in section 2.3, we asked that in relation to the major programmes and projects proposed for the present period, it should provide a reconciliation of actual *vs.* proposed expenditure in terms of expenditure and physical implementation in respect of each of them, e.g. state of completion, nature of completed work *vs.* the estimates, results of the work such as in terms of reduced level of transformer utilisation.

At the time of writing this report, the only information supplied in response to this request was a list of projects with actual expenditure for the first two years of the present period and forecast expenditure for the last year of the present period. The list was supplied without accompanying explanation sufficient to address our request.

PB Report

Western Power did, however, submit with its proposal a report from Parsons Brinckerhoff (PB) on its capex in the present period. [39] Amongst other things, PB argued that justification of the efficiency of outcome of Western Power's capex lay in there being incentives for efficiency in the business and the existence of business processes to deliver efficiency. Project examples were cited (drawn from the population of projects to which PB said the Investment Adjustment Mechanism applied) but the samples related only to minor works. Irrespective of the sampling method, the approach adopted appeared to us to be a loose demonstration of consistency with the new facilities investment test requirements of the Code and did not present us with sufficient information on which to express the opinion required.

Amongst other things, the PB report described Western Power's cost estimation processes and listed, in table 4.1, Western Power's processes "that address the NFIT efficiency criteria". One of the criteria cited in the table was "The evaluation of project costs is accurate and considers the long-term forecast change in load and sales as well as any economies of scale and scope that are available". Western Power's [cost] estimating process was listed in relation to the test and the report then went on to examine it (pp. 29-30), concluding on p. 32 in respect of all points (including cost estimation) that "Western Power's business processes and related governance arrangements, as described in Section 4 of this [the PB] report, act to drive efficient investment and to facilitate investment decision making and outcomes that are aligned with the requirements of Part (a) of the New Facilities Investment Test".

No recognition appeared to be given in the report (which was concluded in September 2008) to the Corporation's concerns regarding its cost estimating capability, which we have just discussed in section 4.2. It is possible that PB was not aware of the difficulties experienced by the Corporation.

This and other elements in the PB text suggest that notwithstanding the title ("assessment of AA1 capex") and intended application of the report, its endorsement of Western Power's cost estimating practice is more relevant to the **next period** than to the present.

An endorsement of Western Power's cost estimating practice in the **present period** would have been difficult to present, given the board's expressed concerns in the area and the remedial actions being taken in 2007 and 2008.

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[38] Western Power states on p. 66 of Appendix 1 to its *Access arrangement information* that "Projects that have been initiated under Western Power's first Access Arrangement are not discussed in detail in this report. Western Power notes that the ERA is being separately advised of those projects that are classed as 'major augmentations' under the Access Code". At the time of reporting, we had not received that information or the findings of any review in respect of it.

[39] See Appendix 5 to the *Access arrangement information*.

Lack of Explanation of Expenditure Variances

The assessment of expenditure variances is a normal step in reviews of the type being undertaken here. The assessment requires information on the physical work done and an analysis of it against the reported cost. It needs to be undertaken project by project for each of the major projects and programmes as some projects may have been deferred or advanced and many will be carried out over more than one financial period.

It is normal, in our experience, for regulated network businesses to provide that information in a sufficiently detailed form to demonstrate what occurred during the period under review, the objective being to show that its estimates and processes were robust and its expenditure variances explainable, leaving no material financial balance that could be attributed to inefficiency.

Unfortunately, Western Power has not yet been able to provide material of this type for our review.

Mitigating Factors

We accept that expenditure overruns *per se* on capital projects do not necessarily imply inefficiency as they may arise, for example, from volume variances – an increase in the work done – or cost variances due to inflation or higher market rates. We note in this context that in the period under consideration, load growth was high – possibly at unprecedented levels, given the buoyant economy in the State – and it appears that the volume variances arose principally in the customer- or demand-driven expenditure categories. Faced with increased demand from customers and requested connections from generators, all of whom were prepared to pay for the added capacity, Western Power clearly had few options other than to proceed with the work or defer it and refuse connections.

We also accept that buoyant economic conditions prevailing at least up to mid-2008 led to a shortage of resources in the country and higher prices for contracted work in the electricity supply industry, including notably higher profit margins. These have already been reported to our knowledge in NSW and may have occurred elsewhere. Higher prices are a normal market reaction when demand exceeds supply and do not imply inefficiency either.

However, the fact remains that Western Power has not yet been able to provide an explanation of the expenditure variances for our review.

Implications for Our Review of Capex in Present Period

Faced with this situation, we were able to consider only the scope and prudence of the investment in the present period and its efficiency in terms of planning and prioritisation – in essence, the **scope and timing** of the capital expenditure made in the present period – and not its efficiency in terms of **cost-effectiveness**.

We discuss the first of these in sections 5.1, 6.1 and 7.1 of the report under the headings transmission, distribution and business support capex. For reasons we explain in those sections, we were satisfied that the capital expenditure in the present period under each of those headings was made in respect of work that a prudent operator, in Western Power's circumstances, would have undertaken during the period. However, because of the lack of information to determine efficiency in terms of cost-effectiveness, we are not able to express an opinion on the consistency of the capital expenditure in the present period with the requirements of the Code for the purpose of adding the investment to the capital base.

4.4 Allowance for "Estimating Risk Factor"

After taking advice from Evans & Peck, Western Power has added an "estimating risk factor" of 3.5% to its capital expenditure estimates for both transmission and distribution. [40] This addition to cost estimates raises a number of issues that we now discuss – a confusion of issues of accounting, management, estimating process, project control, prudence and efficiency.

Evans & Peck's Report [41]

According to the executive summary in Evans & Peck's report, Western Power engaged Evans & Peck to develop a strategy dealing with the claimed asymmetric quantitative risks associated with estimation and delivery of transmission and distribution capex and opex over the next period. Evans & Peck claims that "put simply, history shows that in almost all industries, there is a greater probability that [expenditure on] a project will exceed its budget than come in under budget". Evans & Peck says this is particularly true of long lead-time projects, as are many of Western Power's projects (although we would add the caveat to that claim that long lead times are a characteristic of major transmission system developments more than they are of distribution projects, many of which are in the nature of continuing programmes and routine work).

Evans & Peck says, "Based on [its] analysis of a number of indicators, Western Power's budget to [expenditure] ratios are in line with those found in other network service providers.[42]

Evans & Peck states that its report "is intended to provide a basis for gaining management agreement on the approach to be taken by Western Power in preparing their regulatory submission to the Economic Regulation Authority …". It goes on to say, "The regulatory precedent for some risk allowance in capex projects (and to some extent programmes) is clear. The Australian Energy Regulator (AER) has approved allowances for Powerlink and SP AusNet and Electranet. There have been no allowances for opex."

Evans & Peck notes "establishment of these allowances has not been straightforward. The key issues that continue to concern the AER are: the judgemental nature of the determination of the risk ranges, particularly those determined in a workshop environment, and the ability to complete specific analysis to specific projects / programmes; the overlap between explicit risk allowances under this mechanism and the inclusion of "business as usual" risk notionally incorporated in the weighted average cost of capital; potential overlap between explicit risk allowances and allowances already incorporated in the estimating process; risks should be

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40 See section 3.12 and Appendix 3 of the *Access arrangement information*.

41 The passages quoted in this discussion are taken in the main from the executive summary of that report.

42 Evans & Peck use the term "out-turn cost". We assume this to mean "expenditure". For the avoidance of doubt, we use the terms "cost" and "expenditure" in their normally accepted way, *viz.;* "expenditure" is money going out of a bank account; "cost" is the value of economic resources consumed regardless of when the payment was made.

There may be some confusion over costing terms as well. We have used them in their normal sense, as follows:

(a) **Budget cost** is the amount provided in a financial plan for one or more financial periods and represents the money (or money's worth) outflow of a project plus any allocated indirect costs.

(b) **Projected cost** is (usually) the amount expected to be capitalised in the firm's books, and will include indirect costs, i.e., a share of allocated costs that will not be avoided by not carrying out the project.

(c) **Expected cost** of a project is the sum that is statistically most likely, having regard to the probabilities of variation from the mean of each item in the project cost, i.e., it is the sum of the expected cost of each item.

(d) **Authorised** or **approved cost** is the figure that exists at the time the project is committed and is the figure against which all performance and variance measurements should be made.

(e) **Forecast cost** is commonly the latest estimate of final cost of a project in progress and is needed to update cash flow projections, *inter alia*.

manageable without incurring additional costs; [the] need to realistically assess opportunities, as well as risks; and the unreasonable transfer of risks to customers".

Evans & Peck acknowledges that "whilst the AER has approved risk allowances, [it has] clearly indicated the need for network [service] providers to quantitatively justify their approach. It admits, "This is not an easy task across the portfolio of projects and programmes currently facing Western Power".

Evans & Peck notes, "Western Power is under a different regulatory regime to network service providers under the AER's jurisdiction. Importantly, there is an Investment Adjustment Mechanism" which enables an *ex-post facto* adjustment to recognise changes in the cost of providing system augmentation works resulting from changes in growth rates, customer connections and/or construction costs. It goes on to note that "whilst subject to efficiency and prudence tests, this mechanism changes the comparative risk profile of Western Power in relation to capital works covered by the IAM. However, it does not apply to replacement / refurbishment / reliability and other non-growth-related expenditure, nor does it apply to opex".

Of importance, we note Evans & Peck's statement that "the recommended strategy can be summarised as: Western Power should use the [claimed] precedent in recent AER rulings to justify a risk-based approach to the ERA…" and "to the maximum extent possible, existing estimating packages and experienced internal estimating skills [should] be utilised to quantify risks".

Evans & Peck continues in the main text of its report to state the following.

(a) The long duration of Western Power's works programmes from scope and cost estimation through to completion is a relevant factor (pp. 5, 6 and elsewhere) – to which we would add the caveat that long durations are experienced only in transmission, not distribution (which, in Western Power, is restricted to distribution feeders and distribution substations).

(b) Applying contingencies at a project level can give rise to an excessive contingency at the portfolio level (p. 6) – to which we would add the caveat that if contingencies have been allowed at the project level, then no further allowance is justified.

(c) The first step in quantifying the cost impact is to assess the risks and risk management measures that exist [on individual projects] (p. 7) – to which we would add the caveat that if the business's underlying cost estimating, risk assessment or risk management practices are weak, the business ought to address those issues at its own cost and not apply a factor to recover from consumers cost overruns arising through poor estimation or management.

(d) At the time [of regulatory submissions], many projects can be five to seven years from implementation (p. 9) – to which we would add the caveats that this is not true of distribution projects and that the regulatory period in Western Australia is **three years**, not the five years common in the eastern states. This makes a risk allowance less justifiable.

(e) Evans & Peck's approach draws heavily on the knowledge and experience of estimators and project managers familiar with the situation (p. 9) – to which we would add the caveat that experience in estimating is not the only relevant consideration in this issue: familiarity with the management and governance of businesses and accurate financial control are key factors as well.

(f) Fundamental to the justification of an estimating risk allowance is the recognition that cost risks are often asymmetrical (p.9) – a point to which we return later in this discussion.

(g) The sample of completed projects analysed and reported on as justification of the methodology was small – only 11 projects covering all fields (p. 18), although there is reference in part 2 of the report to receiving schedules of projects and estimates – and the work was carried out with no adjustment for escalation (p. 19), leading in our view to a lack of robustness and to the probable overstatement of estimating errors. [43]

(h) There is recognition on p. 19 that different risks are associated with different types of project – to which we would have added that this must have made determination of the proposed allowance difficult, calling its robustness into question.

(i) The analysis was conducted in a "workshop" environment (p. 21 and elsewhere) – to which we would add the caveat that a workshop is a forum for discussion, not for making analyses. Detailed analyses would need to be an input into the workshop, not an output, and no such detailed analyses are provided for scrutiny.

(j) As far as distribution capex is concerned, Evans & Peck states that "[its] recommendation would be to focus on additional analysis of these programmes" and later, that Western Power subsequently carried out a more detailed analysis, the results of which are reported by Evans & Peck in part 2 of its report (p. 30) – to which we would add the caveat that part 2 provides only a brief explanation of the method and assumptions used and is not sufficient to demonstrate the robustness of the proposed allowance.

(k) Finally, on p. 30, Evans & Peck states "based on [its] analysis and its experience with and observation of the regulatory process to date…Western Power should pursue this issue [application of the proposed allowance] **on the basis of the precedent** and the reality of real risks in the business" – points to which we return later in this discussion. [44]

Precedent Claimed but Not Established

The argument presented by Evans & Peck rests heavily on the precedent that Evans & Peck claims to have been established by the Australian Energy Regulator in agreeing to such an allowance in certain cases of transmission expenditure in other states. No evidence is cited that the AER considers its decision to be a precedent valid beyond the confines of the particular cases it considered or valid in time beyond the period in which it considered them. Nor (and Evans & Peck acknowledge this) has the AER endorsed the addition of any such allowance to distribution capex where, amongst other things, projects are smaller and generally tend to be in the nature of ongoing programmes for which routine cost estimating is accurate or ought to be accurate. Further, in the recently concluded expenditure reviews of the ACT and NSW DNSPs (on which we were the AER's principal technical adviser), no DNSP asked for any such allowance to be added to its estimates. [45]

In addition, we note again that the regulatory period in Western Australia is **three years**, not the five years common in the eastern states. This makes a risk allowance less justifiable.

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[43] The report adds that Powerlink analysed 119 projects.

[44] Our emphasis added.

[45] We understand that the AER agreed to an allowance of around 2.6% for Powerlink and ElectraNet (although we also understand that Powerlink tabled material that, it claimed, supported a higher figure). In its decision on Powerlink and ElectraNet, the AER noted that it considered the likely circumstances over the period the expenditure was being applied to, the number and instances of projects being put forward and the quality and composition of the information supplied to it by the businesses. Source: AER's Decision: *Queensland transmission network revenue cap, 2007-08 to 2011-12* and *Final decision: ElectraNet transmission determination, 2008-09 to 2012-13.*

Thus, we do not consider that the AER's decisions can be taken or should be taken as a precedent or as justification for a case in respect of a different business (Western Power, in this case). Instead, the appropriateness of adding such a factor to Western Power's expenditure estimates (or to anyone else's for that matter) ought to be founded on circumstances of the particular business (Western Power, in this case) and considered solely on its merits. [46]

In the following discussion, we examine it from that standpoint, finding that robust evidence has not been presented in support of the allowance and that Western Power's circumstances do not require its addition anyway.

Less Risk Associated with Distribution Projects and Programmes

Distribution works tend to have a short gestation period and to be of a recurring and routine nature, the costs of which a business ought to be able to predict accurately. Transmission construction work, on the other hand, with its large projects and environmental and other factors, is characterised by more and greater uncertainties. Yet, Evans & Peck proposes to apply the same risk assessment factor to both. We do not consider that logical. Nor do we consider that adequate investigation can have been made into the cost estimation of the distribution work for that conclusion to be reached.

Evans & Peck's Statistical Argument

Evans & Peck has presented a somewhat obtuse statistical argument that "Fundamental to the justification of an estimating risk allowance is the recognition that cost risks are often asymmetric in nature – i.e. there is a greater probability that the cost of a project or program will exceed its most likely cost estimate by a large amount is greater than the probability that the project will come in under budget by a similar amount." [47] The statement as written is meaningless but we infer it possibly to say again that electricity companies are more likely to under-estimate the cost of their capital works than over-estimate them when preparing budgets.

Claiming that projects often overrun their budgets, Evans & Peck argues that a risk allowance should be added to each estimate. In our opinion, however, **more robust cost estimation would be a better solution, and in keeping with sound management as well.**

From a statistical standpoint, Evans & Peck's argument appears to rest on the assumption that budgetary cost estimates for individual projects are set at the mode (most frequently occurring value) and not the mean (weighted average value) of reported expenditures on the population of completed projects that it or others have investigated. This assumption is implied by figure 3.3 of Evans & Peck's report. Seldom, however, are project cost estimates compiled from the sum of the **modal** values of the costs of the component parts. Instead, it is normal for them to be compiled from the sum of the **mean** values. If the costs of component parts are estimated from mean reported values, then the expected outcome of a portfolio of projects is their sum and no additional estimating adjustment is justified. (This applies particularly to distribution works which, as we have stated earlier, tend to be repetitive and about which good cost data should exist.)

A further point we considered is that Evans & Peck's argument appears to rest principally on the analysis of data from other businesses, not Western Power's, where only a small sample (11 projects) was cited in support of its proposed methodology.

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[46] We consider the statement by Evans & Peck on p. 2 of part 2 of its report that "Western Power should use the precedent in recent AER rulings to justify a risk-based approach to the ERA" to be inappropriate.

[47] Page 9 of is report.

No Support in Western Power's Estimating Methods for Addition of Factor

It is not evident from Western Power's documents that individual project budgets have been prepared in a manner that would satisfy the basis upon which the estimating risk factor is claimed to be justified. Of importance, the use of the estimating package "Success Estimator", [48] which incorporates risk distributions for some or all of the inputs in a project's budget build-up, suggests that project budgets are being based on cost expectations in the normal way.

In addition, PB's report (Appendix 5 to the Access Arrangement Information) notes on p. 29 that Western Power's "A0" desktop design estimates are prepared with a level of accuracy of 30% [49] and an "80%" risk allowance; its "A1" proof-of-concept estimates are prepared with a level of accuracy of 20% and the same "80%" risk allowance and its "A2" estimates are prepared with a 10% level of accuracy and a "50%" risk allowance.

The interpretation we place on this is that the A0 estimates are less accurate but have a greater contingency added and thus a lower risk of cost overrun (in other words, the budget is set above the expected value) and likewise but to a lesser extent the A1 estimates. At the top end, however, the A2 estimates are set at the median value. Since the A2 estimates are used only at the point of commitment, it follows that most of the projections for the next period must have used A0 and A1 estimates as the projects concerned are mostly still in the planning stage. This appears to support our point that the addition of the proposed allowance to the estimates we are assessing is not justified.

In further support of our contention, we note that Western Power has added its estimate of future real cost increases to its projections, again reducing the need for a further allowance. [50]

Unfounded Assumption that Estimates are Unbiased

There is a further implicit assumption in Evans & Peck's argument; namely, that individual project budgets are unbiased, that is, that they are a fair representation of "efficient" cost, where factors that might reduce cost are fairly weighted with those that might increase it. If that is not so, then the estimating risk factor adds an unjustified and unjustifiable contingency sum to the estimate.

In this regard, we noted the following comment in Western Power's distribution asset management plan: "*...analysis [of] expenditure for existing programmes indicates that discrepancies in the budgeted and actual expenditure can be attributed to [the] incorrect allocation of programme costs*", and, later: "*As a result, budget expenditure is not a reliable indicator of project activity or progress*". [51] This suggests that there is some risk of inaccurate historical recording of expenditure. Inaccuracy in cost recording casts doubt on the results of the Western Power data on which Evans & Peck has partially relied, in which the ratios of expenditure to budgets of a small sample of projects were put forward as evidence of the systematic underestimation of project costs. (They could just as readily prove that costs overran; and the statement reported earlier in this discussion, that escalation had not been adjusted for in the analysis, suggests a possible cause.)

We cannot be certain that project budgets, built from an examination of expenditure records, are unbiased estimates of efficient cost. Nor can we be certain of the extent to which the

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48 Evans & Peck report, p. 21.

49 This appears to be an estimating tolerance. It is presumed to mean plus or minus 30%. Likewise, for the other tolerances stated in this paragraph.

50 Earlier assessments were made at a time when the full effects of rapid price increases in the installed cost of heavy electrical equipments were still being recognised and analysed. The present situation differs from that.

51 See p. 19 of the distribution asset management plan.

expenditure-to-budget ratios being reported have been influenced by inaccurate records and/or poor cost control.

Further, we would expect there to be, consciously or unconsciously, some allowance for risk in the estimates in addition to the risk factors added in estimates at each of the three levels, as outlined above. Confirmation would thus be required that any identified risks had not already been allowed for in other contingencies in the cost estimates, the provisions for real price escalation, or the unit rates themselves.

Known Shortcomings in Cost Estimating Processes Not Acknowledged

Of importance, Evans & Peck does not appear to have acknowledged (and thus was presumably unaware of) the shortcomings in Western Power's cost estimating and cost control processes in the present period as reported by Western Power itself and discussed in the preceding section of this report.

This casts doubt on Evans & Peck's conclusions, as the data from Western Power on which it partially bases is findings must have come largely from the present period, in which the shortcomings were observed. [52]

We do not see how a valid argument can be made to add a contingency allowance to cost estimates based on an analysis of cost estimating practice and reported expenditure in the present period that was not well founded.

Alliance Contracts Costed on Different Basis

Evans & Peck does not appear to mention (and thus was presumably unaware of) Western Power's alliance contracts or the special arrangements being applied to determine their cost estimates. They constitute a different structure for service delivery that appears to make the proposed risk factor unnecessary.

Operator not to be Relieved of Normal Business Risk

A final point that warrants repetition is that normal business risks that a network business ought to bear (and that are thus reflected in the permitted cost of its capital) should not be transferred to users. This is particularly important in a monopolistic situation where the regulator has a role to play as surrogate for a market, thus preventing a cost-plus culture prevailing in the monopoly service provider, with its accompanying inefficiencies.

We would expect Western Power, with its years of experience, to have sound forecasting and budgeting processes, to refine them periodically and to be capable of producing estimates that prove, in the event, to have been accurate.

Conclusion

Based on the material provided and the points made above, we see no reason why any general risk estimating factor or other such general allowance ought to be agreed to for Western Power's transmission or distribution expenditure, as it has not been established beyond doubt that it is necessary. Accordingly, we do not recommend that the Authority accept the proposed risk adjustment factor allowances in the capex estimates.

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[52] Western Power did not exist in its present form before the present period.

4.5 Other Issues Arising

Incorporation of Real Price Escalation in Projections

The Authority's attention is drawn to the fact that Western Power has incorporated real price escalation in the estimates of future expenditure stated in year 2009 dollars.

We are not able to express a view on the reasonableness of the input assumptions regarding future cost movements. Nor were we able to verify ourselves that the methodology and escalators stated in section 3.1 of Appendix 1 of the Access Arrangement Information had been applied in the stated manner, as an audit would be required for the purpose. We have therefore relied upon Western Power's implicit assurance in the documents that that is the case.

Deliverability

Western Power has recognised that significant resource growth is required in all of its planned delivery mechanisms, with a substantial step-up in FY 2010 to deliver its works programme in the next period.

In its presentation to us it said that the resource strategy would maintain a balanced portfolio of investment but there will be heavy reliance on the market to resource its large transmission projects, in addition to which its distribution contract strategy must be implemented in FY 2009.

It recognises that the availability of resources, network access and project approvals are the key risks for delivery.

Notwithstanding the considerable preparations that Western Power has made to enable delivery of its proposed work programme, the programme remains subject to various risks, as outlined by PB in its assessment report on the deliverability of the proposed access arrangement work programme, a confidential document provided to us by Western Power.

PB said it found the delivery plan to be generally comprehensive and well articulated, although it found some areas that were not addressed in the plan; in particular, a lack of mitigating strategies that Western Power could implement at short notice should any of the other strategies experience implementation delays or other issues which would impact on works delivery.

PB also identified specific risks to the implementation of the delivery plan. For transmission, these include potential delays in implementing specific delivery strategies, the ability to scale up project management capabilities, and the ability to improve quality control and assurance programmes to manage the proposed additional works adequately. It noted that Western Power would also need to retain key planning and project management resources.

For distribution, the specific risks identified by PB included potential delays in implementing specific delivery strategies; improvements required in the supporting systems and processes required to manage the increased workload; misalignment of the vegetation management areas with the distribution delivery zones which may result in a lack of coordination and an inability to capture work synergies and efficiencies; insufficient project management staff available to manage the proposed additional works; immature quality control and assurance programmes; and that inadequate communication channels to the contractors may occur.

For distribution capex, the delivery strategy is that all customer-funded work will be done by the alliances, new commercial agreements with key distribution contractors, its internal workforce or preferred vendors. The delivery challenges are access to the network, the availability of resources and the capacity of the recruitment and training centre.

For transmission capex, the delivery strategy is that capacity expansion lines will be delivered by the alliances, capacity expansion substations will be delivered by the alliances and the internal workforce and customer access and generator access will go to the market if the work exceeds the capability of the alliances. The main delivery challenges are the approval process and access to the network.

For distribution opex, the delivery strategy is to use the internal workforce, new commercial agreements with key distribution contractors and preferred vendors. The delivery challenges are access to the network, the availability of resources and lead times for delivery of additional heavy plant for the fleet.

For transmission opex, the delivery strategy is to use the internal workforce but some work will be performed by contractors. The main delivery challenge is network access.

Conclusion

Whilst recognising the stated risks, we accepted the delivery strategy as reasonable except for distribution opex, where we have recommended phasing of the increase in preventive maintenance due to doubt about Western Power's ability to scale up its planning, execution and control of expenditure in that area at the rate envisaged – see section 9.3 under the heading "Rate of Increase in Expenditure" on p. 82.

Impact of Past Constraints on Capital Expenditure

In 2005, Western Power's constrained capital expenditure estimate showed a significant increase in requirements compared with its historical levels but its proposal noted "the challenge facing the network business is to balance these increased capital expenditure requirements against the inevitable resource and financing constraints that must also be addressed".

We discussed at length in our 2005 report Western Power's strategies for meeting the challenge of resource constraints, the combined effect of resource and finance constraints, the fact that the constraints would lead to higher life-cycle costs and/or lower levels of service than would otherwise be the case, the prioritisation of expenditure in a way that, firstly, ensured that the business complies with safety, environmental and other mandatory statutory requirements then the minimisation of any adverse impact on customers.

It was clear that the financial constraints had been proposed after consultation with the Government.

We noted at the time that, to put the constraints in perspective, the reductions made in capex appeared to be around 50% of the unconstrained expenditure projection in the case of transmission capex and 40% in the case of distribution capex.

The sources of these observations were identified in our 2005 report.

It would appear necessary to bear in mind that the Corporation has experienced resource and finance constraints for some time (notwithstanding the significant increase in expenditure in the present period) and appears likely to continue to experience them.

In this context, it would also appear necessary to recognise, as the Government has acknowledged in the Treasury's submission to the Authority, that a significant further increase in expenditure on the network will be required in the next period and probably beyond to meet the growth in demand and improve the reliability of supply materially. [53]

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[53] Only a modest improvement in reliability of supply is foreseen by Western Power in the next period.

Potential Impact of Changed Economic Situation

The Authority will no doubt wish to consider the impact, if any, that the changed economic situation should have on Western Power's expenditure proposals, noting that the expenditure proposals were prepared in 2008, prior to the rapidly occurring world-wide events of October that year.

We are not able to offer a view on the likely outcome of the situation as it is largely unprecedented and continues to develop daily. In this situation, our review has been based on the demand forecasts and circumstances prevailing at the time of preparation of Western Power's estimates and we have not taken any explicit account of the revised circumstances.

In this context, we have received no updated information on demand growth, other than the following observations from Western Power on p. 32 of its March responses to our questions.

- (a) In releasing its "Request for Expressions of Interest for the Reserve Capacity Cycle" in January 2009, the IMO noted that [its] economics consultant had revised [its] forecast for GSP and GDP in December 2008. This document noted that the new economic outlook is considered to be in line with the forecast for low economic growth conditions for the immediate future but is expected to be restored to the previous outlook within six years. And:
- (b) In 2009 so far, the system peak load has exceeded the previous record on three separate occasions without any severe weather conditions. This situation supports the view that slower economic conditions are unlikely to alter the peak load forecast substantially.

If it were decided that the expenditure projections ought to be adjusted for a lower load growth scenario – not that we are recommending that or the contrary position – it would be necessary for the Authority to ask Western Power to reassess and resubmit its expenditure proposals, as our experience suggests that reassessments of that type need to be carried out by the business concerned because of the information and analytical systems involved.

Planning and Design Criteria and Proposed Revisions to Technical Rules

The Corporation documented its network planning criteria, including security of supply criteria, permissible voltage limits and permissible plant loading guidelines in its *Draft technical rules* in 2005 and they were reviewed by the Authority's Technical Rules Committee with the assistance of PB. We did not review the rules ourselves in 2005, other than to note their general content. [54]

The Access Code requires Western Power's *Technical rules* to be reviewed approximately six months before its next access arrangement is due to commence, *viz.* in July 2009. On 1 October 2008, Western Power submitted *revised technical rules* and a *schedule of proposed changes* to the Authority for assessment. The Authority re-established a Technical Rules Committee to assist it with the assessment of the revised rules, which were anticipated to receive approval in April.

The rules cover the standards, procedures and planning criteria governing the construction and operation of an electricity network.

We have briefly reviewed the proposed revisions to the rules to satisfy ourselves that no changes were proposed that would have the effect of raising unnecessarily the expenditure required in the next period.

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[54] We made observations in our 2005 report about certain proposed changes in Western Power's standards but noted that the cost of the changes had not been included in the estimates in the *Access arrangement information*. However, should the changes be endorsed by the committee and be included in the approved technical rules, a corresponding increase in forecast distribution capital expenditure would be required.

Conclusion

Without pre-empting the findings of the Committee, we found no evidence that caused us to modify our view of Western Power's proposed expenditure in the next period.

5 Transmission Capex

5.1 Expenditure in Present Period

Table 5.1 shows that Western Power's transmission capex is projected to be $972 m over the present period, representing a total expenditure that is 58% above the total approved for the present period (all figures expressed in 2006 dollars). [55]

Table 5.1: Transmission Capex in Present period *vs*. Approved Capex ($ 2006 m)

	Approved AA1				Actual/Forecast AA1				Diff
YE 30 June	2007	2008	2009	Total	2007	2008	2009	Total	
Growth									
Capacity Expansion	79	102	99	**280**	116	99	171	**387**	107
Customer Driven	28	52	11	**92**	18	69	44	**130**	38
Generation Driven	66	39	23	**128**	110	83	127	**320**	192
Replacement & Renewal									
Asset Replacement	14	14	18	**46**	13	11	24	**48**	1
Improvement in Service									
Reliability Driven	1	0	0	**2**	5	5	2	**11**	9
SCADA & Comms	6	1	3	**10**	5	4	4	**13**	3
Compliance									
Safety, Environ & Stat.	8	14	14	**36**	4	5	17	**26**	(9)
Corporate									
IT	2	3	2	**7**	6	11	8	**24**	17
Business Support	5	4	3	**12**	3	3	6	**12**	0
Total	**210**	**230**	**174**	**613**	**279**	**289**	**404**	**972**	359

Source: Western Power.

The total variance was $359 m, of which $337 m or 94% was in the growth-related categories, $13 m or 4% was in service improvement and $17 m or 5% was in business support (discussed in section 7.1). There was a negative variance of $9 m or minus 3% of the total variance in compliance work and the variance in replacement capex was immaterial.

Generation-driven capex more than doubled from the approved expenditure level for the period. The other growth categories, capacity expansion and customer-driven expenditure, increased by around 40% and expenditure on compliance-related maters decreased. There was little change from the approved level in replacement capex and the other categories showed mixed movements.

Explanation of Variances

We requested Western Power to provide, in relation to all major programmes and projects proposed for the present period, a reconciliation of actual *vs.* proposed expenditure in terms of the expenditure and physical implementation for each item (*viz.* state of completion and nature of the completed work *vs.* its cost) We were particularly interested in the reasons for the variations from the approved level of expenditure as a guide to judging the efficiency of the expenditure. However, this information was not received from Western Power, other than in the form of detailed expenditure tables that were supplied largely without explanation. The tables listed around one thousand transmission projects in the period.

[55] Adjustments between 2006 and 2009 dollars in our tables have been made using the consumer Price Index, CPI.

Notwithstanding this lack of information, we were able to identify the major works undertaken in the period and their reported cost from the tables and from presentations made to us by Western Power which together enabled us to determine the general nature of the work carried out in the period. We report our findings in the following sections of this report.

Impact of Cost Escalation

We were also able to analyse the impact of cost escalation during the period to determine the cost variance attributable to it.

Western Power said that both material and labour costs increased at a much higher rate than expected over the present period and it has included future cost escalation in the next period, based on a report commissioned from Access Economics. To illustrate the impact of cost escalation in the present period, we used the weighted cost escalation rates included in Western Power's submission to remove it from the actual expenditure in the present period. The effect of this adjustment is shown in Figure 5.1 and Table 5.2.

Figure 5.1: Impact of Cost Escalation in Present Period ($ 2009 m)

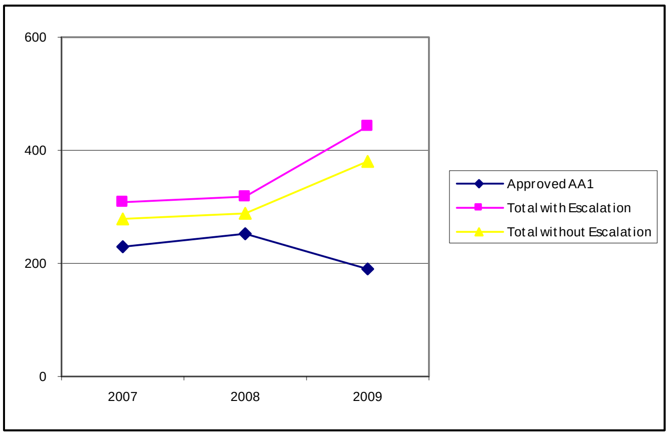

Table 5.2: Impact of Cost Escalation in Present Period ($ 2009 m)

	Present Period (AA1)			
	Actual		Forecast	Total
YE 30 June	2007	2008	2009	
Total with escalation	307	317	444	**1,068**
Total w/o escalation	278	288	382	**948**
Incr. due to escalation	29	29	62	**120**
	10%	10%	16%	**13%**
Approved AA1	231	252	191	**674**
Total increase fm approved				**394**
Balance of increase (excluding escalation)				**274**

The table shows that cost escalation increased the cost of the work undertaken in the present period by $120 m or 13%. It also shows that of the total increase in expenditure of $674 m in 2009 dollars over the approved level for the period, the balance of the increase, attributable to volume variances or other factors, was $274 m.

Growth-Related Expenditure

Expenditure in the present period has been set out by category in Table 5.1 above. We noted that the largest category, capacity expansion, covers routine transmission works to meet forecast load growth and to maintain compliance with the technical rules but excludes work driven by generation impacts and customer block loads. We noted that its primary driver is growth in peak demand and that the sources of demand growth in the period were the increasing penetration of air conditioning at residential and commercial premises, new residential and commercial developments, in-fill housing in inner-city suburbs, the high level of economic activity in the State and isolated larger customer connections, such as new shopping centres, industrial and mining developments.

Annual load forecasts have increased accordingly: the forecast made in 2005 was 120 MW above the forecast made in 2004; that for 2006 22 MW above the 2005 forecast; and that made for 2007 121 MW above the 2006 forecast. Overall, demand growth during the period was 61% above that forecast at the beginning of the period. (The Boddington gold mine alone represented an additional load of almost 4%.)

Peak demand growth has resulted in transformer loadings well above the average for the country. This has resulted in a need to restore them to more sustainable levels by introducing new transformers and zone substations. The increased demand has been accompanied by line loadings approaching their limits, requiring voltage support for the Perth metropolitan area and new transmission lines.

A requirement for the increased use of underground cable in certain locations instead of overhead lines has added to the cost overrun, as did the increased cost of land and easements and the increased cost of plant and labour.

Transformer Loads

Western Power said that its present transformer loading policy [56] was introduced in the late 1990s in response to capital restrictions, leading to an average peak transformer utilisation in 2004 of 79% compared with an Australian average of 56%. An “NCR wind-back policy” was introduced in 2004 to reduce this level. The policy is being implemented over ten years and its effect so far has been to reduce the average transformer utilisation to around 67%. This is a much more satisfactory position but the work will need to continue and be accompanied by supplementary network improvements to reduce distribution feeder loads, although to a large extent, the reduction needed in feeder loads is also achieved by the introduction of the new substations. [57]

The Grid

Western Power said that over the last decade the maximum conductor operating temperature of its overhead lines had been raised from 65°C to 100°C by various conventional methods, allowing them to carry additional load. It says that some lines have reached this higher limit and spare capacity is nearly exhausted.

Recent generation connections in the South West have driven small network augmentation projects including the installation of capacitor banks at 36 sites since 2005, line upgrading (Kemerton-Kwinana, Shotts-Kemerton) the installation of static VAr compensation (SVC), synchronous compensators and new transformers. Major projects to conclude in FY 2009 include a supply for the Boddington mine expansion and the establishment of a new 330 kV terminal station at Neerabup.

Western Power said that minor augmentation alternatives have now been exhausted and that further major works will be required in the next period.

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[56] Based on normal continuous ratings, NCRs.

[57] This point is discussed on p. 44 of Appendix 1 to the *Access arrangement information* and is normal distribution engineering practice.

Generation-Driven Expenditure

Generation-driven expenditure encompasses work to connect new generation plant and includes any associated upgrading and augmentation. Generating plant additions are driven by capacity auctions through the market and power procurement process. To date, the majority of projects have been in the south-western area. Work precipitated during the period included reactive power support for the metropolitan area, a third 330 kV transformer at Kwinana, the Neerabup-Wanneroo-Wangara 132 kV transmission line and SVC plant at Southern Terminal.

Replacement and Renewal Expenditure

The variance in replacement and renewal capex is immaterial in dollar terms. We do not have comparative details of the work undertaken *vs.* that planned at the time the estimates were prepared for the present period but the table of expenditure provided to us indicates the projects undertaken and the expenditure on each. The largest replacement project was poles, with expenditure in the period of $6.5 m in year 2009 dollars. The second largest project was the replacement of 66 kV circuit breakers at a total cost of $3.1 m. The remaining seventy-or-so projects were small and of a conventional type.

Other Expenditure Categories

The variance in the other expenditure categories was immaterial in dollar terms and the work appeared from the expenditure table to be conventional.

Conclusion in Respect of Present Period

In concluding our review of Western Power's transmission capex in the present period, we noted that the pattern of expenditure and its prioritisation were consistent with Western Power's network requirements during the period as we understand them and with the explanations given to us by Western Power.

We noted that 94% of the variance in expenditure between the approved and actual levels is attributable to growth, 4% to service improvement, 5% to business support and a negative 3% to compliance.

We noted that the growth-related work was driven by rapidly increasing demand.

Although Western Power did not provide a reconciliation of actual *vs.* proposed expenditure in terms of the expenditure and physical implementation for each item (*viz.* state of completion and nature of the completed work *vs.* its cost), we were able to identify the major works undertaken in the period and their reported cost from the tables and from presentations made to us by Western Power which together enabled us to determine the general nature of the work carried out in the period.

We considered, based on the projects reviewed and considered representative, that the work had been planned in accordance with accepted transmission system planning procedures, that the major projects had been subjected to detailed studies of options and alternatives, that the need for the work was clear from those reviews and that the major reinforcement projects were in most cases overdue. We thus considered that prudence in the identification of scope and in the efficiency of timing of the execution of the works was established.

We considered that the work undertaken thus appeared to be of a conventional type that would have been undertaken by a service provider acting in accordance with good electricity industry practice in Western Power's circumstances.

We had no reservations about the general nature of the work carried out including connections of generators and consumers, the addition of grid capacity and the reduction of transformer loads.

We noted that $120 m of the variance of $394 m in 2009 dollars is explained by cost escalation.

In conclusion, therefore, and considering the matters discussed in section 4.3, we accepted the scope and prudence of the investment in the present period and its efficiency in terms of planning and prioritisation – in essence, the **scope and timing** of the capital expenditure made in the present period – but are not able to offer an opinion on its efficiency in terms of **cost-effectiveness, as information** on the variances in expenditure was not supplied.

5.2 Forecast Demand

The Code requires the access arrangement information to include information detailing and supporting the service provider's system capacity and volume assumptions. We have briefly reviewed sections B2 and C2 of the Access Arrangement Information in this regard, noting the methodology used for preparation of the forecasts.

We note from this material that the forecast rate of growth in energy throughput over the next period is projected to be 2.2% p.a. on average whilst maximum demand is forecast to grow at 3.3% p.a. Those rates of growth relate to the economic circumstances prevailing at the time of preparation of the access arrangement proposal. Rates of growth in the present economic situation may differ and have not been considered by us, as the expenditure we review is based on the growth projections made earlier. [58]

The Authority may wish to ask Western Power to confirm its expenditure proposals if the impact of the present economic slowdown is expected to be significant or of long duration, although the comments on p. 32 under the heading "Potential Impact of Changed Economic Situation" should be noted.

5.3 Proposed Expenditure in Next Period

Western Power's proposed transmission capex in the next period compared with that in the present period is shown in Table 5.3.

[58] We understand that the service provider's forecasts are to be reconcilable with the forecasts presented in the *Statement of opportunities* prepared by the Independent Market Operator. According to Western Power, its demand forecast for the bulk transmission system is broadly based on the demand forecasts in the Statement of Opportunities, allowing peak network flows in the bulk transmission network to be modelled; its demand forecasts for individual substations are developed by extrapolating previous system peaks for each substation to allow peak power flows at each substation to be modelled; and its demand forecasts for each load area, which allow peak power flows in the network elements in each load area to be modelled, are developed using the bulk transmission forecasts and the individual substation forecasts.

Table 5.3: Current and Forecast Transmission Capex ($ 2009 m)

YE 30 June	Present Period (AA1) Actual 2007	2008	Forecast 2009	Total	Next Period (AA2) Proposed 2010	2011	2012	Total	Diff
Growth	268	275	376	**919**	610	752	480	**1,842**	923
Replacement	14	12	27	**52**	32	32	40	**104**	51
Service Improvement	11	9	7	**27**	20	24	26	**70**	43
Compliance	4	6	19	**29**	47	43	38	**129**	100
Business Support	10	15	16	**40**	21	19	9	**49**	9
Total	**307**	**317**	**444**	**1,068**	**730**	**870**	**594**	**2,194**	**1,126**

Source: Western Power.

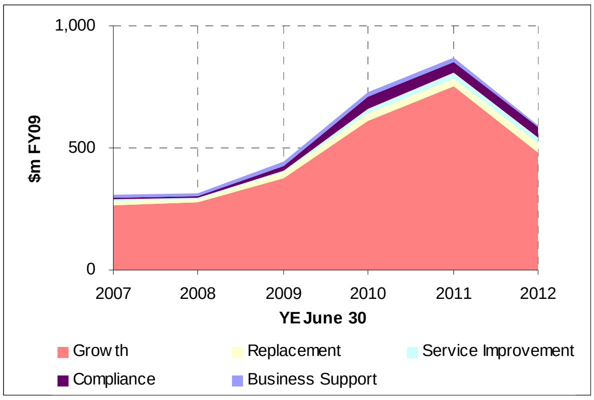
The total capex proposed in the next period is $2,194 m compared with an estimated $1,068 m in the present period (both expressed in 2009 dollars), an increase of 105%.

All categories of expenditure are projected to rise in the next period, with the largest increase in dollar terms being in growth-related activities and the highest in percentage terms being in compliance-related activities. Growth-related expenditure accounts for 82% of the increase in dollar terms and 84% of the expenditure in the next period. Figure 5.2 shows the trend of expenditure from FY 2007 to FY 2012, indicating clearly that it is driven principally by growth.

The figure also shows a sharp peak in the expenditure in FYs 2010 and 2011.

The expenditure streams are dealt with individually by expenditure category in the remainder of this section of the report except for business support, which is dealt with in section 7.1 and the estimating risk factor allowance included under each heading, which has been considered and rejected in section 4.4.

Figure 5.2: Trend in Transmission Capex ($ 2009 m)



Impact of Cost Escalation

We analysed the impact of cost escalation to determine the cost variance attributable to it in Western Power's transmission capex for the next period. The method used was that described on p. 35 of this report under the heading "Impact of Cost Escalation". The impact of removing it from the expenditure projections is shown in Figure 5.3 and Table 5.4.

Figure 5.3: Impact of Cost Escalation in Next Period ($ 2009 m)

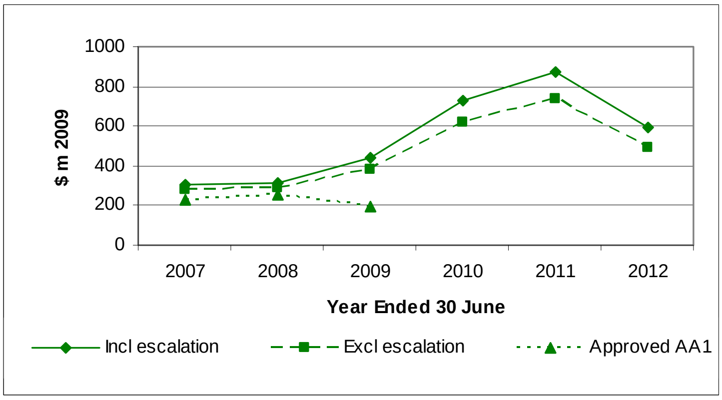


Table 5.4: Impact of Cost Escalation in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Increase
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Total with escalation	307	317	444	**1,068**	730	870	594	**2,194**	+ 105%
Total w/o escalation	278	288	382	**948**	618	736	488	**1,842**	+ 94%
Incr. due to escalation	10%	10%	16%	**13%**	18%	18%	22%	**19%**	

The table shows that cost escalation is projected to increase the cost of the work undertaken in the next period by 19%. It also shows that of the total increase in expenditure in the next period of 105% over the present period (in year 2009 dollars), 11 percentage points are attributable to escalation in costs, the balance being attributable to volume variances or other factors.

5.4 Growth-Related Expenditure

Table 5.5 shows that Western Power's growth-related transmission capex is projected to be $1,842 m over the next period, approximately double that in the present period.

Table 5.5: Growth Capex in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Capacity Expansion	127	109	188	**425**	460	449	293	**1,202**	778
Customer Driven	19	76	48	**143**	36	112	50	**198**	56
Generation Driven	121	91	140	**352**	93	165	121	**379**	28
Estimating Risk					21	25	16	**62**	62
Total	**268**	**275**	**376**	**919**	**610**	**752**	**480**	**1,842**	**923**

Source: Western Power.

Capacity Expansion

Western Power is proposing to spend $1,202 m on increasing transmission system capacity over the period compared with $425 m in the present period. The heaviest expenditure is forecast to be in the first two years. Expenditure in the capacity expansion category accounts for 65% of growth-related expenditure and covers transmission works to meet forecast load growth and to maintain compliance with the technical rules but excludes work driven by generation impacts and customer block loads.

We noted that its primary driver continued to be growth in peak demand and the other factors applicable in the present period.

The background to the expenditure proposals has been outlined in section 5.1. The projections include several major transmission projects to provide voltage support in metropolitan Perth, additional capacity in the north-west, eastern goldfields and Albany, an ongoing programme to reduce substation transformer loads and other conventional work.

We were provided with a list of projects totalling this amount, ranging in size up to $330 m.[59] The largest projects included in the list and thus in the estimates cited in Table 5.5 were the proposed 330 kV line to Geraldton (for which $327 m was allowed), the 330 kV line from Shotts to Wells Terminal to provide voltage support for the Perth metropolitan area ($142 m allowed), various related works, a 132 kV line from Kojonup to Albany ($125 m allowed), a new CBD substation ($41 m allowed) and numerous other works ranging in cost from minor amounts to $40 m. (The estimated costs cited in this paragraph are before escalation or the addition of the 3.5% estimating risk allowance that has been added to estimates.)

The main project in the south-east, the 330 kV line from Shotts to Eastern Terminal, was categorised by Western Power as "generation driven" but the essence of the work is to provide voltage support for load growth in metropolitan Perth, so we do not agree with the classification of the work as generation-driven, considering that it is a "core grid" development matter. [60] The point is not material to our work but if it were to affect the charging of capital contributions, for example by increasing them unnecessarily, it could be of concern to the Authority and so we mention it here for the Authority's attention.

Detailed engineering reports on the projects were not requested although the need for expenditure on them was discussed, along with their salient features, and a number of planning reports and studies were provided in relation to the major investment items, sufficient to show that the projects involved had been the subject of detailed study and optimisation.

Detailed information was provided on the alliance contracting arrangement and independent reviews of the largest planned investment, the 330 kV line to Geraldton and its associated works. That information was reviewed.

We noted in particular that Western Power's analyses reported considerable load at risk if the planned work was not undertaken.

Western Power advised us that similar procedures were being followed on the other major planned transmission works, allowing us to conclude that the projects examined were representative.

Western Power noted, correctly, that the mix of projects is expected to change but considered the estimate, in total, reasonable. (The possibility of changes in some of the projects is already evident, given the changed economic conditions, even though the estimates had been finalised by Western Power only in 2008, in time for submission with the access arrangement proposal. For example, a recent study of the Albany line by SKM suggests that the addition of around 20 MW of generating plant at Albany would allow a decision on the major line investment to be deferred until the future of the prospective Grange mining development is better known. There are many such possibilities and the position of several of the individual works remains fluid.)

59 The list included around 300 projects, covering all the transmission capital expenditure categories.

60 SKM's reports on solutions to the voltage support requirement match our view.

In other instances, such as the major works in the south for the relief of line loadings and the provision of more voltage support on the network, the work is overdue, as is the continued relief of excessive transformer loadings.

We briefly reviewed Western Power's main planning standards, network development plans and reports and found them to be reasonable and generally in accordance with international practice. We noted the significant steps taken to improve the cost estimating processes in time for the access arrangement proposal, as already discussed in section 4.3 of this report. We noted also that Western Power had engaged PB to assist with the preparation of its expenditure plans.

Although we found some of Western Power's documentation confusing, difficult to interpret and in some instances out of date, we concluded nevertheless that on balance, having considered the network development plans and other documents and explanations provided to us and having discussed all the major projects with Western Power's technical staff, the works proposed were reasonable to assume in respect of necessity, options and timing. We therefore concluded that the expenditure forecast for growth capex in the next period represented a realistic expectation of future expenditure needs.

Connection-Driven Expenditure

Western Power is proposing to spend $577 m over the next period on connection-driven work (referred to as customer-driven and generation-driven in Western Power's documents and in our tables), compared with $495 m in the present period. This represents an increase of 39% in customer-driven work and 8% in generation-driven work over the present period. [61]

The two biggest projects involved are a 220 kV line to Grange Resources ($161 m allowed), and a 330 kV line to Gindalbe Metals ($67 m allowed). [62]

We understand from Western Power that, broadly speaking, generation proposals are considered for inclusion in its estimates if they have been assigned capacity credits by the Independent Market Operator, are well developed and currently making progress with access studies and applications. Generation proposals are not allowed for in the estimates if they are relatively undeveloped proposals, small and insignificant to overall generation planning or exhibit a history of deferral.

The projections also include the cost of transmission works (including zone substations) associated with new customer bulk loads. In each case, work includes associated upgrading and augmentation related to the connection as well as the connection itself.

The Corporation noted, correctly, that the mix of projects is expected to change but it added that it considered that the estimate in total was reasonable. Details of the projects were not provided or requested.

The expenditure is contingent on customer developments and the commissioning of new generation capacity, both of which are uncertain. Of particular relevance, we note the uncertainty that surrounds the timing and location of future generation capacity additions and the consequential uncertainties that surround the need for transmission system investment.

Most of the expenditure under this category is expected to be funded by the initiator of the work – the bulk load customers or the generators – and therefore any increase or decrease in expenditure should be matched by corresponding increases or decreases in capital contributions.

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[61] The 330 kV line from Shotts to Wells Terminal was categorised by Western Power as connection-driven but for the reasons discussed in the preceding section, we discussed it under the heading "capacity expansion".

[62] These figures exclude escalation and the estimating risk allowance.

Whilst the precise scope of work that is likely to be undertaken remains unclear as the expenditure requirements are still prospective, we were satisfied for the purpose of our review that the proposals and their likelihood had been assessed and prioritised in a practical and reasonable manner by Western Power. We also considered that the expenditure forecast under this heading was a reasonable estimate, given the load forecast at the time the expenditure forecasts were prepared.

5.5 Replacement Expenditure

Western Power proposes to spend $104 m on asset replacement over the next period, compared with $52 m in the present period. This is an increase of 98%, although to put the increase in perspective, it should also be noted that replacement expenditure comprises only 5% of total transmission capex in the period. Expenditure is forecast to be $32 m in each of the first two years and $40 m in the third.

Around 50 projects totalling this amount, ranging in size up to $9 m, were listed in the expenditure tables. The bulk of the expenditure was on substation equipment replacement – transformers, circuit breakers, etc. Detailed engineering reports on the projects were not provided although the programmes were described in Appendix 1 of the *Access arrangement information* and the *Transmission asset management plan 2008/09 to 2017/18.*

We reviewed the transmission asset management plan and noted that the rationale for identifying the assets to be replaced considered a number of factors including age, type, reliability, technology, maintenance records and inspection data and we were satisfied that the replacement forecast was based on the assessment of equipment condition and risk. [63] Since we were satisfied that the replacement expenditure forecast was based on assessment of condition and risk, we were also satisfied it represented a prudent scope of work that could be expected to efficiently minimise cost and risk through appropriate replacement timing.

The level of expenditure and its timing proposed by Western Power for the next period also appears reasonable in that it demonstrates a rising trend that is matched to the Corporation's understanding of the age and condition of its transmission network and to the ability of the company to resource the scope of works.

5.6 Service Improvement Expenditure

Table 5.6 shows that Western Power's transmission-related capex on service improvement is projected to be $70 m over the next period, compared with $27 m in the present period.

Table 5.6: Service Improvement Capex in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Reliability Driven	5	5	2	**12**	6	10	9	**25**	13
SCADA & Comms	6	4	5	**15**	13	13	16	**42**	28
Estimating Risk					1	1	1	2	2
Total	**11**	**9**	**7**	**27**	**20**	**24**	**26**	**70**	**43**

Source: Western Power.

63 This was also supported by the question response document DMS# 5474399v2 where Western Power summarised the asset inspection practices.

SCADA and Communications

The major SCADA and communications item is the master station (around $11 m), the balance being made up of about 32 other projects of up to $2 m each in cost. We reviewed the drivers for the SCADA expenditure and considered that they aligned with our expectations for this type of asset. The description of the items in this category in section 5.9 of the *Access arrangement information* says that SCADA and communications components of capital works for new substations and generators are included but later in the same section, they are said to be excluded. Western Power confirmed the latter interpretation and we accepted the proposed expenditure as reasonable.

Reliability

The majority of the reliability-related expenditure is for a new substation near Perth, primarily to improve reliability in the Sawyers Valley and Byford areas that are currently serviced by very long feeders. The new substation will enable the area to be served by more feeders. We accepted the explanations given and consider the expenditure reasonable.

5.7 Compliance-Related Expenditure

Expenditure for safety, environmental and statutory compliance is projected to increase to $129 m over the next period, compared with $29 m in the present. The increase reflects the deferral of work in this area in the present period because of resources being diverted to address the high rates of increased demand.

The largest items in this expenditure category are transmission pole replacements ($36 m), upgrading of substation security ($18 m), removal of asbestos ($14 m), replacement of non-complying stays and insulators ($13 m) and various other lesser projects.

The pole replacement work is driven by a mix of condition assessment and changed standards against which condition is assessed; namely, the revised Australian overhead line design standard. [64] We noted that the rate of pole replacement described is, in general, in accordance with an expected pole life of 50 years and that the replacements are prioritised based on risk.

The substation security work is described as a continuing programme in response to the *National guidelines for prevention of unauthorised access to electricity infrastructure.* The asbestos removal work is also described as a continuing programme. The replacement of stays and stay insulators is described as a response to a review of wet withstand flashover capability. The remaining expenditure items are conventional.

The proposed work is of a conventional nature for a transmission business, is necessitated by the need to manage identified risks and/or comply with the applicable standards and regulations and is thus considered prudent. We therefore consider the expenditure items under this category reasonable. [65]

5.8 Efficient Costs

Having considered the reasonableness of the **scope and timing** of work estimated by Western Power for the next period – and recognising that the particular projects and programmes included in the projections may change in scope or timing in some cases or be abandoned or replaced by other alternatives during the period – we then considered the adequacy and

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64 Electricity Networks Association C(b)1: 2006: structural and engineering standards for HV transmission lines.

65 We do not comment on the level of risk being carried, as that is a matter for the business and its shareholder to determine.

appropriateness of Western Power's policies and procedures as far as they affect the robustness of the cost estimates and the efficiency of its costs.

We noted the points discussed in section 4.2 under the heading "Implications for Review of Expenditure in Next Period", particularly the improvements that Western Power is making in its cost estimating capability.

We noted that independent reviews of the cost estimate for the North Country project had found the estimate to be reasonable.

We noted also that SKM's review of Western Power's cost estimates for routine transmission work in the next period had also found its cost estimates to be reasonable.

We reviewed the documents in which Western Power explained the method of building up its transmission cost estimates and noted from its delivery plan and other confidential papers the arrangements it has made for contracting out its major transmission works in the next period.

We noted that it had included real cost escalation in its estimates, as quantified by us in section 5.3 above.

We were satisfied that Western Power had followed conventional and reasonable policies and procedures in the identification of its transmission-related capital expenditure requirements in the next period and the determination of least-cost solutions when making its investment decisions in that area.

We noted that Western Power has conventional procurement policies that ensure that major items of plant are purchased competitively and that alliance arrangements for the construction of major projects are of a conventional nature that provide incentives to meet target costs.

The practices and policies we observed and note above led us to conclude that Western Power can reasonably be expected to minimise the cost of its transmission-related capital expenditure for the next period efficiently.

5.9 Conclusion – Transmission Capex

In summary, therefore, based on the preceding analysis in this section of the report and the assessments in section 4, we conclude as follows.

(a) Considering the matters discussed in sections 4.3 and 5.1, we accept the scope and prudence of the investment in the present period and its efficiency in terms of planning and prioritisation – in essence, the **scope and timing** of the capital expenditure made in the present period – but are not able to offer an opinion on its efficiency in terms of **cost-effectiveness,** as information on the variances in expenditure was not supplied.

(b) Confirmation of the matter noted in section 5.6 should be sought from Western Power.

(c) In relation to the next period, we consider that Western Power's proposed transmission-related capex, including the transmission component of business support capex that we discuss in section 7 of this report, is reasonable provided the proposed risk estimating allowance is removed. The recommended adjustment is shown in Table 5.7. [66]

[66] A comparison of total capex with the replacement cost of the asset base would normally be made at this point in the review as a further check of reasonableness but was not attempted in the absence of an up-to-date replacement cost valuation of the assets.

Table 5.7: Recommended Transmission-Related Capex in Next Period ($ 2009 m)

	Next Period (AA2)			
	Proposed			Total
YE 30 June	2010	2011	2012	
Proposed	730	870	594	**2,194**
Less: estimating risk factor	24	29	20	**73**
Recommended	706	841	574	**2,121**

6 Distribution Capex

6.1 Expenditure in Present period

Table 6.1 shows that Western Power's distribution capex is projected to be $1,377 m over the present period, representing a total expenditure that is 55% above the total approved for the present period (all figures expressed in 2006 dollars).

Table 6.1: Distribution Capex in Present period *vs*. Approved Capex ($ 2006 m)

	Approved AA1				Actual/Forecast AA1				Diff
YE 30 June	2007	2008	2009	Total	2007	2008	2009	Total	
Growth									
Capacity Expansion	30	32	37	**100**	74	58	81	**213**	113
Customer Driven	90	105	119	**314**	177	178	120	**475**	161
Gifted Assets	15	19	22	**57**	22	19	86	**126**	70
Replacement & Renewal									
Asset Replacement	17	28	29	**74**	27	37	56	**119**	45
SUPP	17	15	16	**48**	21	21	27	**68**	20
Metering	4	8	9	**21**	11	12	11	**34**	12
Improvement in Service									
Reliability Driven	9	19	13	**41**	5	18	26	**49**	9
RPIP	10	10	11	**31**	9	22	20	**52**	20
SCADA & Comms.	2	2	2	**6**	2	2	2	**7**	1
Compliance									
Safety, Environ & Stat.	27	44	43	**114**	33	33	60	**125**	12
Corporate									
IT	19	16	14	**49**	18	32	22	**72**	23
Business Support	12	14	8	**35**	9	9	19	**37**	2
Total	**253**	**312**	**324**	**889**	**408**	**438**	**531**	**1,377**	**488**

Source: Western Power.

The total variance was $488 m of which $344 m or 70% was in the growth-related categories, $77 m or 16% was in replacement, $30 m or 6% was in service improvement, $12 m or 2% was in compliance and the remaining $25 m or 5% was in business support (discussed in section 7.1).

Capacity expansion and gifted assets more than doubled from the approved level for the period and all other categories except SCADA, compliance and business support increased by between 20% and 66%. The other three categories increased by between 5% and 16% from the approved level.

Combination of Customer-Driven and Gifted Expenditure Categories

Our view is that when assessing customer-related expenditure levels, gifted (or vested) assets or those towards the cost of which customers have contributed should be treated no differently from other customer-driven capex and should be considered part of the total expenditure level under this heading, the vesting or capital contributions being only a different form of financing. Therefore, in our assessment, the total customer-driven capex was $601 m in the present period, compared to the approved level of $371 m. This represents an increase of 62% over the approved level. These figures are in 2006 dollars. [67]

We examined this matter in our 2005 review of the proposed expenditure for the present period, as an increase was projected at that time over the preceding period. We noted several related factors, including advice from Western Power that its expenditure forecasts were based on a continuation of the then current subdivision design standards, despite prospective design changes that would increase costs. It may be appropriate to seek clarification of the expenditure in this category from Western Power when the other requested information is received.

Explanation of Variances

As the case of transmission capex, we requested Western Power to provide, in relation to all major programmes and projects proposed for the present period, a reconciliation of actual *vs.* proposed expenditure in terms of the expenditure and physical implementation for each item (*viz.* state of completion and nature of the completed work *vs.* its cost) We were particularly interested in the reasons for the variations from the approved level of expenditure as a guide to judging the efficiency of the expenditure. However, this information was not received from Western Power, other than in the form of detailed expenditure tables that were supplied largely without explanation. The tables listed around fourteen hundred projects in the period.

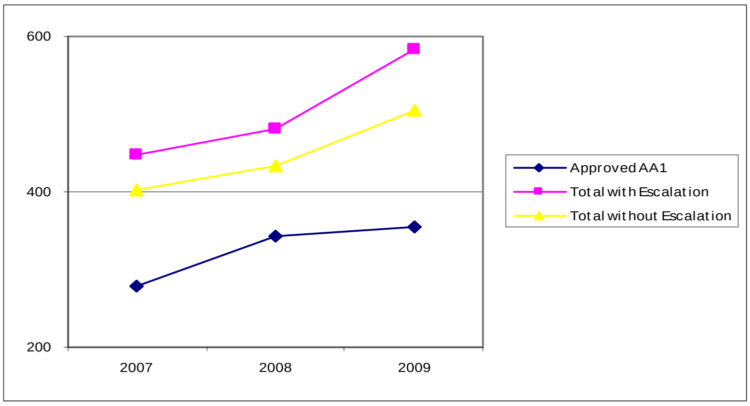
Notwithstanding this lack of information, we were able to identify the major works undertaken in the period and their reported cost from the tables and from presentations made to us by Western Power which together enabled us to determine the general nature of the work carried out in the period. We report our findings in the following sections of this report.

Impact of Cost Escalation

We were also able to analyse the impact of cost escalation during the period to determine the cost variance attributable to it.

The method used was that described on p. 35 of this report under the heading "Impact of Cost Escalation". The impact of removing it from the expenditure projections is shown in Figure 6.1 and Table 6.2.

Figure 6.1: Impact of Cost Escalation in Present Period ($ 2009 m)



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[67] We also noted a significant jump in the gifted component from FY 2008 to FY 2009. In itself, that was not of interest to us but the Authority, if considering the reasonableness of customer capital contributions or like methods of financing, may have an interest in the change. While customer capital contributions may be taken into account when assessing the allowable return on the regulated asset base, it is important to recognise that, if the property in the assets has passed to the utility (as is often the case), the utility needs to depreciate them and, at the expiration of their useful life, to replace them. We have not researched the implications of IFRS (if any) on the accounting treatment of assets partly funded by customers, but, typically, the assets are capitalised at cost and the capital contributions amortised to revenue over the life of the assets.

Table 6.2: Impact of Cost Escalation in Present Period ($ 2009 m)

	Present Period (AA1)			
	Actual		Forecast	Total
YE 30 June	2007	2008	2009	
Total with escalation	448	481	583	**1,512**
Total w/o escalation	403	434	505	**1,342**
Incr. due to escalation	46	47	78	**170**
	11%	11%	15%	**13%**
Approved AA1	278	343	355	**976**
Total increase fm approved				**536**
Balance of increase (excluding escalation)				**365**

The table shows that cost escalation increased the cost of the work undertaken in the present period by $170 m in 2009 dollars or 13%. It also shows that of the total increase in expenditure of $536 m in 2009 dollars over the approved level for the period, the balance of the increase, attributable to volume variances or other factors, was $365 m.

Growth-Related Expenditure

Expenditure in the present period has been set out by category in Table 6.1 above. We noted that the largest category, growth, includes capacity expansion, customer-driven work and gifted assets. The expenditure includes routine distribution works to meet forecast load growth and maintain compliance with the technical rules. We were satisfied that it was, in general, required to support increased customer connections, to reduce network feeder utilisation levels, to integrate new zone substations, to upgrade overloaded distribution transformers and to upgrade conductors with insufficient fault ratings for the prospective fault levels.

We were also satisfied that Western Power’s distribution network capacity had not kept up with growth over the last decade due to limited resources, resulting in high feeder utilisations.

Replacement Expenditure

Replacement expenditure included three categories: the SUPP, meter replacements and the remainder. The main expenditure items other than the SUPP and meters were poles (around $88 m), conductors (around $9 m) and distribution transformers (around $9 m), accounting for the majority of the investment.

Service Improvement Expenditure

Service improvement expenditure included three categories: the RPIP, SCADA and communications and the remainder. The main expenditure items other than the RPIP, SCADA and communications were the “forty worst feeders” programme (around $28 m) and targeted reclosers (around $25 m), accounting for the majority of the investment.

Compliance-Related Expenditure

Compliance-related expenditure showed little variance from the approved level and accounted for 9% of total opex in the period. The work involved remedying clashing conductors, replacing unsatisfactory fuses and services, addressing voltage regulation problems and attending to other routine matters.

Conclusion in Respect of Present Period

In concluding our review of Western Power’s distribution capex in the present period, we noted that the pattern of expenditure and its prioritisation were consistent with Western

Power's network requirements during the period as we understand them and with the explanations given to us by Western Power.

We noted that 70% of the variance in expenditure between the approved and actual levels is attributable to growth, 16% to replacement, 6% to service improvement, 2% to compliance and the remaining 5% to business support.

We noted that the growth-related work was driven by rapidly increasing demand and that Western Power's growth-related capex was, in general, required to support increased customer connections, to reduce network feeder utilisation levels, to integrate new zone substations, to upgrade overloaded distribution transformers and to upgrade conductors with insufficient fault ratings for the prospective fault levels.

We were also satisfied that Western Power's distribution network capacity had not kept up with growth over the last decade due to limited resources, resulting in high feeder utilisations.

Although Western Power did not provide a reconciliation of actual *vs.* proposed expenditure in terms of the expenditure and physical implementation for each item (*viz.* state of completion and nature of the completed work *vs.* its cost), we were able to identify the major works undertaken in the period and their reported cost from the tables and from presentations made to us by Western Power which together enabled us to determine the general nature of the work carried out in the period.

We considered that the expenditure had been adequately planned and the major investments subjected to appropriate studies of options and alternatives.

We considered that the work undertaken thus appeared to be of a conventional type that would have been undertaken by a service provider acting in accordance with good electricity industry practice in Western Power's circumstances.

We had no reservations about the general nature of the work carried out including connections of consumers and the addition of feeder capacity.

We noted that $170 m of the variance of $536 m in 2009 dollars is explained by cost escalation.

In conclusion, therefore, and considering the matters discussed in section 4.3, we accepted the scope and prudence of the investment in the present period and its efficiency in terms of planning and prioritisation – in essence, the **scope and timing** of the capital expenditure made in the present period – but are not able to offer an opinion on its efficiency in terms of **cost-effectiveness, as information** on the variances in expenditure was not supplied.

6.2 Proposed Expenditure in Next Period

Western Power's proposed capex in the next period compared with that in the present period is shown in Table 6.3.

Table 6.3: Current and Forecast Distribution Capex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Growth	300	279	315	**895**	336	354	371	**1,061**	167
Replacement	64	76	103	**243**	158	175	206	**539**	296
Service Improvement	19	46	53	**118**	61	68	79	**208**	90
Compliance	37	36	66	**138**	91	107	140	**338**	200
Business Support	29	44	46	**119**	62	55	27	**144**	25
Distribution Total	**448**	**481**	**583**	**1,512**	**708**	**759**	**823**	**2,290**	**777**

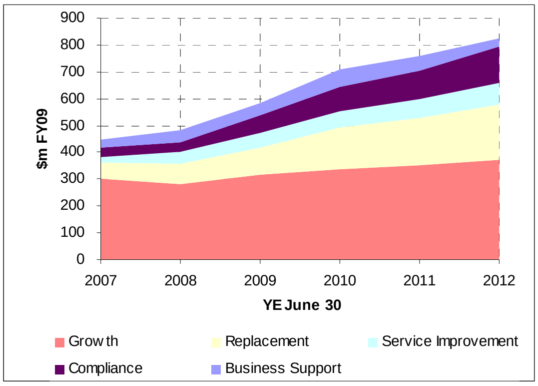
Source: Western Power.

The total capex proposed in the next period is $2,290 m compared with an estimated $1,512 m in the present period (both expressed in 2009 dollars), an increase of 51%.

All categories of expenditure are projected to rise in the next period with the largest increase in dollar terms being in replacement work and the largest in percentage terms being in compliance-related work. Replacement-related expenditure accounts for 38% of the increase in dollar terms and 24% of distribution capex in the next period. Figure 6.2 shows the trend of expenditure from FY 2007 to FY 2012.

The expenditure streams are dealt with individually by expenditure category in the remainder of this section of the report except for business support, which is dealt with in section 7.1 and the estimating risk factor allowance included under each heading, which has been considered and rejected in section 4.4.

Figure 6.2: Trend in Distribution Capex ($ 2009 m)



Impact of Cost Escalation

We analysed the impact of cost escalation to determine the cost variance attributable to it in Western Power's distribution capex for the next period. The method used was that described on p. 35 of this report under the heading "Impact of Cost Escalation". The impact of removing it from the expenditure projections is shown in Figure 6.3 and Table 6.4.

Figure 6.3: Impact of Cost Escalation in Next Period ($ 2009 m)

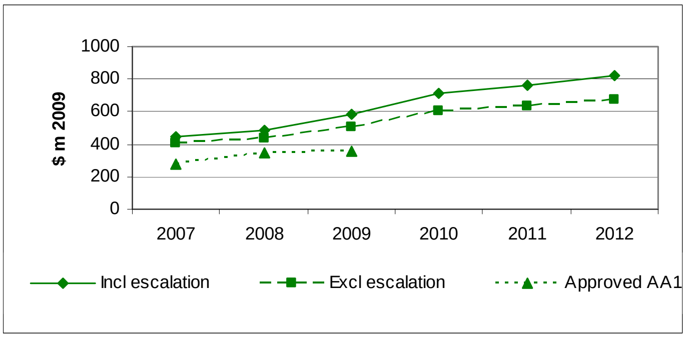


Table 6.4: Impact of Cost Escalation in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Increase
YE 30 June	2007	2008	2009		2010	2011	2012		
Total with escalation	448	481	583	**1,512**	708	759	823	**2,290**	+ 51%
Total w/o escalation	403	434	505	**1,342**	601	638	672	**1,910**	+ 42%
Incr. due to escalation	11%	11%	15%	**13%**	18%	19%	22%	**20%**	

Source: Western Power.

The table shows that cost escalation is projected to increase the cost of the work undertaken in the next period by 20%. It also shows that of the total increase in expenditure in the next period of 51% over the present period (in year 2009 dollars), 9 percentage points are attributable to escalation in costs, the balance being attributable to volume variances or other factors.

6.3 Growth-Related Expenditure

Table 6.5 shows that Western Power's growth-related distribution capex is projected to be $1,061 m over the next period compared to $895 m in the present period, an increase of 19%.

Table 6.5: Growth Capex in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Capacity Expansion	82	63	89	**234**	78	91	97	**266**	32
Customer Driven	195	195	132	**522**	149	152	158	**459**	(63)
Gifted Assets	24	21	94	**139**	98	100	103	**301**	162
Estimating Risk	0	0	0	**0**	11	12	13	**36**	36
Total	**300**	**279**	**315**	**895**	**336**	**354**	**371**	**1,061**	**167**
Cust Driven + Vested	218	216	226	**661**	247	252	261	760	**99**

Capacity Expansion

Western Power is proposing to spend $266 m to increase distribution system capacity over the period, compared to $234 m in the present period. This expenditure includes all demand-driven reinforcement of the high voltage and low voltage distribution systems. High voltage expenditure (around $70 m plus $165 m in the CBD) includes feeder reinforcement to cope with load growth, achieve or maintain compliance with the planning criteria and accommodate new substation developments under the transmission programme. Low voltage expenditure (around $30 m) includes distribution transformer overload relief and low voltage feeder optimisation. The reduction of high voltage feeder utilisation ratios is an important driver. The work is outlined in appendix 1 to the *Access arrangement information* and the other information provided to us, including the tables of expenditure referred to earlier in this section. The tables identify the main expenditure categories and can be reconciled with the proposed level of expenditure.

Engineering details of the projects were not requested although the need for expenditure was discussed, along with its salient features, and a number of planning reports and studies were provided in relation to the major investment items, sufficient to show that the projects involved were appropriate and the methods employed were consistent with general industry practice.

We noted that Western Power had engaged PB to assist with the preparation of its expenditure plans.

Noting in particular the relatively small uplift in this expenditure category over the level in the present period, the ongoing need to reduce feeder loads, the projected continued high rate of load growth, the routine nature of the work and the conventional practices applied; and noting also that we were satisfied from our discussions with Western Power's technical staff that they had a full grasp of the issues involved, we accepted the expenditure proposed as reasonable in the context that the works are necessitated by and limited to the expected load growth and prudent and conventional management of network capacity.

Customer-Driven Expenditure and Gifted Assets

Western Power is proposing to spend $459 m on customer-driven capex in the next period compared with $522 m in the present period. In addition, it is expecting to receive vested assets as shown in Table 6.5 above.

To repeat a point made in section 6.1, our view is that when assessing customer-related expenditure levels, gifted (or vested) assets should be treated no differently from other customer-driven capex and should be considered part of the total expenditure under this heading, the vesting being only a different form of financing. Therefore, in our assessment, the total customer-driven capex is $760 m in the next period, compared to $661 m in the present period. This represents an increase of 15% over the level in the present period. Table 6.6 summarises the data and shows the resulting average cost per connection over the next period. The figures in this paragraph are in 2009 dollars.

Table 6.6: Analysis of Customer Access Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Var.
YE 30 June	2007	2008	2009		2010	2011	2012		
Customer Driven	195	195	132	**522**	149	152	158	**459**	- 12%
Gifted Assets	24	21	94	**139**	98	100	103	**301**	117%
	218	216	226	**661**	247	252	261	**760**	+ 15%
Projected Connections (k)					29.27	29.54	29.81		
Cost per Comnnection (k)	CD only				5.10	5.14	5.29		
	% increase p.a.					0.9%	2.8%		
	CD + Vested				8.44	8.52	8.76		
						0.9%	2.8%		

Source: Western Power.

The table shows that the average cost per connection is reasonably stable in the next period, although the uplift of 15% from the present period remains.

Given the stability of the cost per connection in the next period (and noting that it is an average of all types of connection), we consider the projected expenditure in this category reasonable.

6.4 Replacement Expenditure

Western Power proposes to spend $539 m on distribution asset replacement over the next period, compared to $243 m in the present period. This represents an increase of 122% over the level in the present period. Details are shown in Table 6.7.

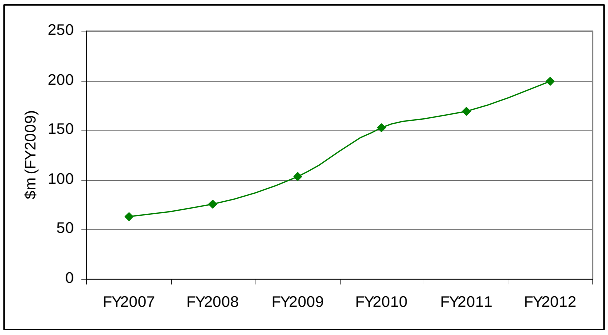
Table 6.7: Distribution Replacement Capex - Period Comparisons

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Asset Replacement	29	41	61	**131**	71	84	129	**285**	154
SUPP	23	23	29	**75**	35	38	23	**96**	22
Metering	12	13	13	**37**	46	46	48	**139**	102
Estimating Risk	0	0	0	**0**	5	6	7	**18**	18
Total	**64**	**76**	**103**	**243**	**158**	**175**	**206**	**539**	**296**

Source: Western Power.

To put the proposed level of expenditure in perspective, the average annual replacement expenditure proposed under this category in the next period is only around 0.8% p.a. of the replacement cost of the distribution assets as reported by Western Power. [68] That this is below a long-term sustainable level has been recognised by Western Power and the trend in replacement expenditure is increasing, as illustrated as illustrated in Figure 6.4. This trend is expected to continue after the next period. [69]

Figure 6.4: Trend in Distribution Replacement Capex



Nature of the Expenditure

Around 20 projects or programmes totalling the forecast amount ranging in size from $0.5 m to $145 m were listed in the expenditure tables. The bulk of the expenditure is projected to

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68 Table 1 in the *Distribution asset management plan* states that the replacement cost of the distribution network fixed assets is $23,971 m. It notes that this figure is significantly higher than reported in the previous plan. (Note: The figure is higher than we would expect, based on data from other networks. However, if, say, a replacement cost of around $9,000 m was chosen (based on our data), the annualised replacement expenditure as a percentage of network replacement cost would be around 2% p.a. and thus not above a reasonable long-term sustainable level.)

69 Some expenditure classified as “compliance” is also replacement in nature. Its inclusion here would increase the percentage reported. Also, a percentage measure of this type in relation to the whole asset base may be misleading, given that the high levels of new underground reticulation installed during the recent high growth period will have the effect of giving a relatively higher proportion of low maintenance assets in the asset base than in other networks

be on pole replacements (around $145 m), pole reinforcement (around $34 m), conductor replacement (around $36 m) and 17 other programmes totalling around $40 m. The other programmes cover all the normal areas – transformers, switchgear, etc and are in the range of $0.5 m to $14 m each, the largest being distribution transformers.

This is in addition to a three-phase meter replacement programme (around $98 m) and four other meter programmes totalling around $41 m accounting for the metering estimate, and the State Undergrounding Power Programme with its expenditure of $96 m.

Details of the programmes were available in Western Power's documents, in addition to which we made various enquiries to satisfy ourselves that the replacements were generally predicated on condition rather than on age and that the processes followed to determine the expenditure were sound. We noted in particular Western Power's March response to our questions in which it identified a number of inspection and condition-based assessment programmes, the asset populations involved and the targeted number of replacements over the next period. We also noted that in cases where Western Power considers the risks of failure to be manageable, a number of asset classes are managed through replacement on failure consistent with normal industry practice.

Pole Replacement and Reinforcement

Western Power has a large population of wooden poles that, in accordance with normal industry practice, are tested periodically to confirm their safety. Nevertheless, failures occur for various reasons and replacements are undertaken. Additionally, reinforcement is possible in some situations where deterioration in condition is detected and can extend the life of the pole, deferring the need for replacement and its accompanying higher cost.

Western Power advised us that its forecast pole replacement expenditure is based on condition surveys, will replace around 1.2% of the pole population p.a., will address its list of condemned poles at a rate more or less equal to the rate at which they are presently being detected and will reduce the present pole failure rate from 34 per 100,000 poles p.a. to 10 or less over the next period. [70] It recognises that its present pole failure rate is higher than the national average and the proposed programme is clearly a measure addressing that matter.

Western Power also notes that along with other businesses, it may have a large number of poles in respect of which the design loads are less than would be required if the line were to be re-built today in accordance with current industry standards. If that is considered an issue, we suggest that it seeks advice from a suitably qualified and independent party on what should be done, if anything, to remedy any significant hazard. [71]

Other than in these respects, the need for pole replacement is a long-standing matter and the concerns expressed by the technical regulator are not new. However, our responsibility, in this review, is restricted to the assessment of Western Power's proposed expenditure in the next period alone. Based on the fact that its expenditure is projected to address the rate at which poles are currently being condemned, we consider its projected level of pole replacement expenditure to be reasonable.

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70 Source: Appendix 1 section 7.4.1 of the *Access arrangement information.*

71 We understand that the Director of Energy Safety in Western Australia or the applicable regulations in Western Australia may now require all poles to comply with the **current** industry line design standard. If so, and if a large number of poles were to be involved, that requirement would appear to be impractical to achieve other than in the long term. It is not desirable (or normal, in our experience) for regulations or other statutory instruments to require private parties to re-build serviceable assets without giving the parties involved a reasonable time to respond. In the present case, 'reasonable' would mean several years. Note: the general principles discussed in section 6.6 in relation to compliance-related expenditure are also relevant here.

Impact of Possible Directives

If, however, the Director of Energy Safety mandates a higher level of pole replacement or other remedial work, then Western Power will presumably need to submit a revised expenditure projection for the Authority's consideration. To our knowledge, no such directive has been given yet, or revised expenditure projection presented. [72]

In such a circumstance, we also consider that the general principles discussed in section 6.6 in relation to compliance-related expenditure generally would also be relevant here. That is, we also consider that Western Power should satisfy itself that sound economic analyses underpin the requirements of the directive. If there is doubt about the robustness of these analyses, Western Power should obtain an independent assessment of the most economical approach to follow and the risks entailed.

Other Replacement Programmes

After making enquiry, we were satisfied that the other replacement programmes were also of a conventional type and could be accepted as reasonable. [73]

State Undergrounding Power Programme

The SUPP aims to convert the reticulation in older urban areas to underground supply. Western Power contributes 25% of the costs, the remainder being funded by the State and local government bodies. The expenditure forecast is based on Western Power's expectation of the funding that will be continued over the next period.

Conclusion

Noting the routine nature of the work; noting that the expenditure forecast is underpinned by condition assessments or the continuation of historical levels of expenditure; noting that asset condition (or replacement on failure in some cases) is prudent practice; noting that we were satisfied from our discussions with Western Power's technical staff that they had a full grasp of the issues involved; and noting also that the explanations given to us were consistent with our knowledge of the assets and their maintenance requirements gained from our previous reviews of this expenditure, we accepted the expenditure proposed as reasonable.

6.5 Service Improvement Expenditure

Table 6.8 shows that Western Power's distribution-related capex on service improvement is projected to be $208 m over the next period, compared with $118 m in the present period. This is an increase of 76%.

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[72] After concluding our work, we were advised by the authority that the Director of Energy Safety's report on its 2008 audit had been concluded. We obtained a copy of the report and noted that it identified what it said were three critical issues that had not been addressed effectively over the preceding 24 months, including (a) the development and implementation of a network-wide pole replacement programme to achieve at least 15,000 pole replacements p.a. within three years; and (b) the identification and replacement of high-risk unsupported poles in the rural distribution network. We understand the report to say that such poles may have complied with the engineering codes when they were installed but do not have the strength and safety factors to comply with the bending strength specified in the 1991 *Guideline for the design and maintenance of overhead distribution and transmission lines.* We note that the Directorate expects to issue orders requiring Western Power to address these matters. Western Power (in the distribution network to which the report is addressed) plans for 6,200, 7,000 and 9,350 pole replacements in years FY 2010 to FY 2012 respectively (in line with its expected pole condemnation rates), plus approximately 9,000 pole reinforcements p.a. If it is directed to increase the rate of replacement to 15,000 p.a. or to undertake significant other work to meet the Director's requirements, its replacement capex will need to be increased substantially in this area.

[73] We noted, in respect of distribution transformers, that the replacement of transformers less than 300 kVA in capacity is expensed. We consider that unusual as distribution network service providers in other jurisdictions normally capitalise the replacement of high-value identifiable assets such as distribution transformers.

Table 6.8: Service Improvement Capex in Next Period ($ 2009 m)

YE 30 June	Present Period (AA1) Actual 2007	Actual 2008	Forecast 2009	Total	Next Period (AA2) Proposed 2010	Proposed 2011	Proposed 2012	Total	Diff
Reliability Driven	6	19	29	**54**	44	54	67	**166**	112
RPIP	10	24	22	**57**	8	5	3	**17**	(40)
SCADA & Comms	2	2	3	**7**	6	6	6	**18**	11
Estimating Risk	0	0	0	**0**	2	2	3	**7**	7
Total	**19**	**46**	**53**	**118**	**61**	**68**	**79**	**208**	**90**

Source: Western Power.

Reliability

Distribution related expenditure for reliability improvement is projected to be $166 m over the next period, compared to $54 m in the present period. Expenditure is forecast to rise over the period continuing a trend that has existed at least since FY 2007.

The main items are feeder refurbishments in the North Country (around $35 m), a similar programme in the south (around $11 m), a programme to remedy the worst sections of feeders (around $28 m), re-conductoring for load break switch installations (around $26 m), distribution automation (around $11 m) and other smaller, routine, programmes.

After enquiry, we consider the expenditure reasonable.

Rural Power Improvement Programme

The rural power improvement programme is partially funded by the State with the objective of improving reliability for rural customers where improved reliability cannot be justified economically. The expenditure forecast is based on Western Power's expectation of the funding that will be continued over the next period.

SCADA

Expenditure on SCADA and communications is expected to be $18 m over the next period with an emphasis on network automation. After enquiry, we consider the expenditure reasonable.

6.6 Compliance-Related Expenditure

Distribution-related expenditure for safety, environmental and statutory reasons is projected to be $338 m over the next period compared with $138 m in the present period, an increase of $200 m or 145% over the present period. This is a very large increase and comes with the clear implication of more to follow in future periods to complete the actions proposed.

The proposed expenditure in this category will account for 15% of Western Power’s distribution-related capital expenditure in the next period, compared with 9% in the present period.

Nature of the Work

The work proposed entails the rectification of faults in network components. The faults may have arisen from poor design, inadequate maintenance or deterioration due to age but in some instances it appears that assets, presumably built in accordance with earlier standards or with policies considered appropriate at the time, do not now comply with present standards – as in the case of overhead line design, for example.

The main programmes are the replacement of overhead customer service connections (around $52 m), bush fire mitigation measures (around $44 m), reinforcement to achieve power quality compliance (around $36 m), measures to reduce conductor clashing on high voltage lines (around $31 m), work to reduce the incidence of pole-top fires (around $26 m), the replacement of earth mats at overhead switch locations (around $25 m), targeted low voltage network upgrading (around $17 m), replacement of a particular type of overhead conductor (around $15 m) and thirty or so other smaller, conventional programmes that add to the total for the next period of $338 m. The programmes are summarised well in section 7.6 of Appendix 1 of the *Access arrangement information* and so, to avoid confusion, the descriptions are not re-stated here.

In most instances, there are many thousands of installations in each category and it will be a major undertaking to inspect and, where necessary, repair or replace these items. The work will take several years and will need to be prioritised within Western Power’s resource constraints, including its financial constraints.

Whilst Western Power’s financial constraints could conceivably be overcome by a compulsory levy on customers (or another method of raising finance) to cover the cost of the work, its other resource constraints are also stretched to their limit and are likely to remain so for several years as a backlog of work on the network needs to be addressed.

General Principles

Given the magnitude of this expenditure and its implications for the future we would like to set down the following facts that we believe are beyond dispute before we proceed to the evaluation of the individual items.

(a) As was the case at the time of our 2005 review, the increased expenditure is said to be necessary for the Corporation to comply with directives from the Director of Energy Safety and remedial actions agreed with him, to comply with the requirements of the *Electricity (supply standards and system safety) regulations* and to meet the Corporation’s general obligation to maintain good practice and to manage risk prudently.

(b) Some of the directives appear to be a reaction to an incident involving a fatality or damage.

(c) The electricity supply industry is not alone in having to address defects in its assets from time to time but it attains a high level of public prominence when electrocutions occur or fires or other damage arise from electrical causes.

(d) The normal method of evaluating the necessity for remedial action in such cases is a financial and economic evaluation of the costs and benefits of the options involved (including doing nothing), the objective being to select the least-cost viable option. A “financial” analysis in this context means an analysis of the costs and benefits to the business concerned; and an “economic” analysis means an analysis of the costs and benefits to the country as a whole – including the avoided cost of fatalities or other damage. [74]

(e) The presumption is that the safety directives driving the proposed expenditure are supported by this type of analysis but no such directives have been seen by us nor any such analyses provided. [75]

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74 An analogous situation arises in relation to roads and highways, where the avoidance of fatalities arising from vehicle accidents is taken into account when prioritising expenditure on road improvements. (The only difference seems to be that in the case of roads, fatalities are expected whereas in the case of electricity supply, they are not.)

75 We have not taken any steps to establish the existence of these analyses.

(f) If there is doubt about the robustness of such analyses, Western Power should obtain an independent assessment of the most economical approach to follow and of the risks entailed.

(g) Last, the point has already been made in this report [76] that it is not desirable (or normal, in our experience) for regulations or other statutory instruments to require private parties to re-build serviceable assets without giving the parties involved a reasonable time to respond. [77]

Programmes with Long-Term Expenditure Implications

The replacement of customer overhead service connections extends an existing programme that commenced in FY 2004, following fatalities involving service connections using PVC cable. We are aware of similar programmes in other network businesses. The scope of the programme appears ambitious, with a target replacement rate of 9% of the 300,000 connections each year. The method of prioritising the work is not described in the documents.

The high voltage clashing conductor programme appears to be a response to a directive from the Director of Energy Safety following an incident on the network. The programme described by Western Power involves a combination of intermediate poles and/or extended cross-arms on around 50,000 long line spans, of which 7,250 are to be dealt with in the next period.

The bush fire mitigation work is intended to replace overhead distribution conductors and associated pole-top hardware that have been found to be in poor condition and are located in extreme bushfire risk areas. The work is underpinned by condition assessments and targets risk.

The fire-safe fuses work is a smaller programme that will address only high-risk cases.

Notwithstanding this, these programmes, taken together, have significant expenditure implications, as their full completion will require around $620 m to be spent. [78]

Other Programmes

The power quality compliance reinforcement programme appears to be principally the conventional task of addressing low voltage complaints and the forecast level of activity is as based on historical trends.

Pole top equipment replacement in high fire risk areas is aimed at compliance with the revised Australian line design standard. Line inspection data is to be used to target the work.

The pole-top switch earth mat replacements continue an existing programme to bring earthing design into conformity with the *Electricity (supply standards and system safety) regulations* 2001.

The remaining expenditure items in this category, as described by Western Power, appear conventional.

Conclusion

To conclude in relation to the proposed compliance-related expenditure in the next period: taking into account the information provided by Western Power, the general principles noted

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76 See footnote 71 on p. 55.

77 This point appears to have been recognised in the main instances where an extended programme is foreseen but only a portion of the work is planned in the next period.

78 Expressed in 2009 dollars and calculated by increasing the costs of the parts to be undertaken in the next period pro rata by the full quantity of work foreseen.

above, the long-term financial impact of the programme of work that has been proposed and the need for the Corporation to act prudently and minimise costs efficiently we consider that the proposed expenditure reasonable for the purpose of this review.

However, we also consider that Western Power should satisfy itself that sound economic analyses underpin the requirements cited. If there is doubt about the robustness of these analyses, Western Power should obtain an independent assessment of the most economical approach to follow and the risks entailed.

6.7 Efficient Costs

As in the case of transmission capex discussed in section 5.8; having considered the reasonableness of the **scope and timing** of work estimated by Western Power for the next period, we then considered the adequacy and appropriateness of Western Power’s policies and procedures as far as they affect the robustness of the cost estimates and the efficiency of its costs.

We noted the points discussed in section 4.2 under the heading “Implications for Review of Expenditure in Next Period”, particularly the improvements that Western Power is making in its cost estimating capability.

We reviewed the documents in which Western Power explained the method of building up its distribution cost estimates and noted from its delivery plan and other confidential papers the arrangements it has made for contracting out work in the distribution area in the next period.

We consider that Western Power has a satisfactory basis for estimating the cost of this work for the next period, given its routine nature.

We noted that it had included real cost escalation in its estimates, as quantified by us in section 6.2 above.

We were satisfied that Western Power had followed conventional and reasonable policies and procedures in the identification of its distribution-related capital expenditure requirements in the next period and the determination of least-cost solutions when making its investment decisions in that area.

We noted that Western Power has instituted a risk-management-based approach to prioritise its capex and opex. This should ensure that it achieves the best outcomes for the expenditure made.

We therefore concluded, based on the observations listed above and the preceding text, that its forecast distribution-related capital expenditure for the next period reflected efficient costs.

6.8 Conclusion – Distribution Capex

In summary, therefore, based on the preceding analysis in this section of the report and the assessments in section 4, we conclude as follows.

(a) Considering the matters discussed in sections 4.3 and 6.1, we accept the scope and prudence of the investment in the present period and its efficiency in terms of planning and prioritisation – in essence, the **scope and timing** of the capital expenditure made in the present period – but are not able to offer an opinion on its efficiency in terms of **cost-effectiveness,** as information on the variances in expenditure was not supplied.

(b) In relation to the next period, we consider that Western Power’s proposed distribution-related capex, including the distribution component of business support capex that we discuss in section 7 of this report, is reasonable provided the proposed risk estimating allowance is removed. The recommended adjustment is shown in Table 5.7. [79]

Table 6.9: Recommended Distribution-Related Capex in Next Period ($ 2009 m)

	Next Period (AA2)			
	Proposed			Total
YE 30 June	2010	2011	2012	
Proposed	708	759	823	**2,290**
Less: estimating risk factor	22	24	27	**73**
Recommended	686	735	796	**2,217**

79 A comparison of total capex with the replacement cost of the asset base would normally be made at this point in the review as a further check of reasonableness but was not attempted in the absence of an up-to-date replacement cost valuation of the assets.

7 Business Support Capex and Opex

7.1 Capex

Western Power's non-system capex comprises expenditure on non-system IT, plant, equipment, land, buildings and other non-system assets. [80]

Expenditure in Present Period

Table 7.1 shows that Western Power's business support capex is projected to be $145 m over the present period, representing a total expenditure that is $42 m or 40% above the total in the approved for the period (all figures expressed in 2006 dollars).

Table 7.1: Business Support Capex in Present period *vs*. Approved ($ 2006 m)

YE 30 June	Approved AA1				Actual/Forecast AA1				Diff
	2007	2008	2009	Total	2007	2008	2009	Total	
Business Support	17	18	11	**47**	12	11	26	**49**	+ 4%
IT	21	19	17	**57**	23	42	30	**96**	+ 70%
Total	**38**	**37**	**28**	**103**		**54**	**56**	**145**	**+ 40%**

Source: Western Power.

The table shows that Western Power will overspend against its allowances for both business support (by 4%) and IT systems (by 70%) over the period. Business support capex was under-spent in the first two years of the period but is forecast to be more than double the approved level in the final year of the period. The increase in expenditure in FY 2009 is due to the implementation of the building refurbishment project, "Project Vista", which is discussed under the next heading, since most of the expenditure is in the next period.

Expenditure on IT systems increased significantly in the last two years of the present period. Western Power advised that this is due to a strategic programme of works implemented as part of the organisational change process presently under way.

Assessment

As in the case of transmission and distribution capex, we requested Western Power to provide, in relation to all major programmes and projects proposed for the present period, a reconciliation of actual *vs.* proposed expenditure in terms of the expenditure and physical implementation for each item (*viz.* state of completion and nature of the completed work *vs.* its cost) We were particularly interested in the reasons for the variations from the approved level of expenditure as a guide to judging the efficiency of the expenditure. However, this information was not received.

Notwithstanding this lack of information, we were provided with a list of projects just prior to reporting which enabled us to identify the major projects undertaken in the period and their cost. We noted that $30 m (in 2009 dollars) of IT capex in the first two years of the present period, was classified as "various small IT projects". [81] This item accounted for 40% of the

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80 Motor vehicles and corporate-wide IT systems are purchased outside the covered business and use of these assets within the covered business is recovered by an annual or usage charge to the covered business.

81 The major projects listed were expenditure on the customer information system, outage management system, establishment of a works management system and assets system rationalisation.

IT expenditure in the period. With such a large proportion of the expenditure undefined, we cannot provide an opinion in relation to this expenditure item without further clarification and explanation from Western Power

Proposed Expenditure in Next Period

Business Support

Business support capex in the current and next period is shown in Table 7.2.

Table 7.2: Current and Forecast Business Support Capex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Business Support	13	12	28	**54**	47	45	18	**110**	+ 105%
IT	26	47	33	**106**	36	29	18	**83**	- 21%
Total	**39**	**59**	**61**	**159**	**83**	**74**	**36**	**193**	**+ 22%**

Source: Western Power.

The total expenditure proposed is $193 m, an increase of 22% from the present period. The increase is primarily due to the implementation of a major upgrading of the head office and five metropolitan depot sites, Jandakot Prinsep Road, Kewdale, Balcatta/Stirling, Mount Claremont and Mandurah. The project has been named “Project Vista”.

Western Power states that the catalyst for Project Vista was the need to remove asbestos in the ceiling space of the west building of the head office. This required each floor to be stripped, thus providing the opportunity to refurbish the offices to a modern standard. The project was expanded to remedy sub-standard accommodation at some depots and to bring the buildings up to modern building code standards. The refurbished buildings will provide an open plan environment that supports the aim of the business change process to create a more innovative and open culture. The opportunity is also being taken to upgrade to a “green star” accreditation.

We reviewed the business case for the project and noted that options were considered, including moving to new buildings but the options were not considered feasible. We noted that the extra cost of the green star accreditation had a payback period of 15 years from expected opex savings but based on experience of others who had achieved accreditation, additional benefits were expected as well, such as improved employee productivity.

We considered the need for the expenditure to be well founded and agree that there should be significant improvements in staff productivity and morale arising from the improved working conditions.

IT Expenditure

Western Power is proposing to spend $83 m on IT facilities in the next period, compared to $106 m in the present period, a decrease of 21%. The forecast IT expenditure includes all information technology capital projects, including a Strategic Programmes of Work (SPoW) programme that covers major projects and all purchases of computer hardware and software.

Western Power states that the SPoW is one of several major business change programmes aimed at achieving a business transformation to meet the needs of energy market reform and meet internal business improvement targets. The SPoW is an integrated programme that will review and change many of Western Power’s core business processes and replace several core customised legacy systems with contemporary industry standard solutions. The programme is said to represent a significant investment in modernising both Western Power’s business practices and its supporting IT capability. The largest expenditure item in the next period is $25 m on a new geographic information system (GIS). Other major projects include refreshing the MIMS asset and works management system, a new network customer information system, a workforce management system, and rationalisation of assets systems. We reviewed the list of projects included in the SPoW and samples of internal business cases and approval requests. The system purchases proposed are typical of those used in network businesses. Our review of the documentation provided showed that the need for the system expenditures had been established and appropriately prioritised; options were considered as part of the decision-making process; and consideration had been given to the likely benefits including quantification of cost savings, improvements in business efficiency and reduction of business risk.

7.2 Opex

Western Power's non-system Opex comprises expenditure on activities that support the core network business such as human resources, finance and corporate management. The category also includes the costs of insurance, rates and taxes.

Expenditure in Present Period

Table 7.3 shows that Western Power's business support opex is projected to be $211 m over the present period, representing a total expenditure that is $52 m or 20% below the total approved for the period (all figures expressed in 2006 dollars).

Table 7.3: Business Support Opex in Present period *vs*. Approved Level ($ 2006 m)

	Approved AA1				Actual/Forecast AA1				Diff
YE 30 June	2007	2008	2009	Total	2007	2008	2009	Total	
Business Support	62	66	68	**196**	60	69	82	**211**	+ 8%
IT & T (market reform)	20	22	25	**68**	0	0	0	**0**	n/a
Total	**82**	**88**	**93**	**263**	**60**	**69**	**82**	**211**	**- 20%**

Source: Western Power.

The main reason for the under-expenditure is that no costs have been allocated to IT & T. We asked for the reason and were advised that these costs are now allocated to business units via an internal charge and are included under the other headings in the reported opex and capex activities for the period. Apart from IT & T, other business support costs were 8% higher than approved for the period. These costs rose steeply over the period with forecast FY 2009 costs expected to be 21% above the approved level. Western Power advised us that the increases are due to the need to support a larger than expected works programme, increases in labour costs above the rate of inflation and an extra $5 m allowed for strategic initiatives in FY 2009.

Proposed Expenditure in Next Period

Business support opex in the current and next period is shown in Table 7.4.

Table 7.4: Current and Forecast Business Support Opex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Transmission	19	21	24	**63**	27	28	29	**84**	+ 33%
Distribution	47	55	66	**168**	77	79	81	**236**	+ 40%
Total	**65**	**76**	**90**	**232**	**104**	**107**	**110**	**320**	**+ 38%**

Source: Western Power.

The total expenditure proposed in the next period is $320 m, compared with $232 m in the present period, an increase of 38%. A 16% increase in support costs is forecast in FY 2010, followed by modest increases over the last two years of the next period. A detailed breakdown of business support expenditure is shown in Table 7.5

We were provided with detailed breakdowns of costs in each of the cost centres for the present period and the next period. They showed that the cost increases in the next period are principally driven by: the expected increase in real labour costs; additional staff resources (particularly in the human resources and finance areas) to support the larger capex and opex works programmes; several new initiatives in the human resources and strategic and corporate affairs cost centres (a total of around $3 m p.a. from FY 2009); and a list of proposed strategic initiatives (a total of $5 m p.a. in the next period in the strategy and corporate affairs cost centre). We were satisfied with explanations of the increase in support personnel and the new initiatives to support the increased work programme and develop workforce and leadership capability in the organisation.

We sought further information on the proposed strategic initiatives. We were told that they fell into three main categories: operational excellence, "green" initiatives, and customer- and community-focused initiatives. Their major focus for this expenditure is to improve business performance and we agreed with the need to have a focus on business improvement as it should improve the effectiveness of expenditure in future periods. Similarly, increasing safety awareness is a prudent activity for a distribution business. The business also has a responsibility to act in a socially responsible manner and we considered that the green initiatives and other community activities contributed to the Corporation's responsibility in that regard. The quantum of expenditure on these strategic initiatives amounts to approximately 1% of total opex expenditure, or 0.2% of total expenditure, over the period. We considered this was an appropriate investment in improving core business performance and consider the expenditure is reasonable.

Table 7.5: Details of Business Support Opex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Human resources	16	15	18	**48**	21	21	21	**63**	+ 30%
Strategy and corp affairs	12	12	17	**42**	23	23	24	**70**	+ 67%
Finance	11	12	14	**37**	16	16	16	**48**	+ 32%
Legal & governance	3	4	6	**14**	7	7	7	**22**	+ 60%
CEO	1	3	2	**7**	1	1	1	**4**	- 45%
Insurance	13	15	16	**44**	17	18	19	**54**	+ 23%
Rates & taxes	5	6	7	**17**	8	8	9	**25**	+ 49%
Energy safety levy	3	4	4	**11**	4	4	4	**12**	+ 12%
Design & estimating	0	4	4	**8**	4	4	4	**13**	+ 59%
Fringe benefit tax	2	1	1	**3**	1	1	1	**3**	- 5%
Extended outage payments	0	0	0	**1**	2	2	2	**6**	+ 424%
Total	**65**	**76**	**90**	**232**	**104**	**107**	**110**	**320**	**+ 38%**

Source: Western Power.

We were concerned about the proposed increase in the forecast "extended outage payments" – payments made to customers when restoration targets are not met. Presently, Western Power makes these payments only on request from customers. However, its forecast expenditure is based on **all** eligible customers receiving payments. We consider it illogical that the business should benefit by receiving revenue for penalty payments that may never be made and thus consider that, unless the business can demonstrate that it will identify and make payments to all eligible customers, the projections include an allowance based on historical payment levels. An alternative would be to set up a mechanism based on actual payments.

Overhead Allocation Methodology

Whilst not directly affecting business support costs, Western Power advised us that a change had been made from July 2008 to the way in which indirect costs associated with the running of operational divisions are recovered. Prior to July 2008, indirect costs were allocated based on direct labour hours. This resulted in projects or work streams that were being resourced by the internal work force attracting heavy indirect cost allocations whilst those that were resourced by external service providers attracted either very low or no indirect costs. From July 2008, the non-productive costs of direct labour (such as leave, etc) are added to the hourly labour rate and the other indirect costs are allocated based on project or programme costs. The change has resulted in a reduction in the size of the pool of indirect costs and a shift of about $22 m of expenditure from opex to capex in FY 2009.

The impact on the categories of expenditure has been a drop of 21% in transmission opex and 7% in distribution opex and an increase of 5% in transmission capex and 1% in distribution capex.

7.3 Summary of Recommended Levels of Expenditure

Business Support Capex in Present Period

We concluded that Western Power’s business support capital expenditure in the present period was work that a prudent operator, working in Western Power’s circumstances, would have undertaken, subject to clarification from Western Power of the projects referred to in section 7.1 under the heading “Expenditure in Present Period”.

Whilst we found no evidence of inefficient investment, we are not able, due to the lack of information just referred to, to express an opinion on the **efficiency** of the capital expenditure in the present period.

Business Support Capex in Next Period

We considered the business support capex proposed for the next period reasonable without adjustment for the following reasons.

- The need for the expenditure had been established and it was of a type that is typically required by network businesses;
- Business cases had been prepared for all major expenditure items, considering options and giving reasons for selecting the recommended outcomes.
- A governance structure in place to consider and approve business cases.
- An appropriate procurement policy in place to ensure a transparent purchasing process.

Business Support Opex in Next Period

Having considered the factors reported in this section, we conclude for the purpose of this review that a reduction of $2 m p.a. should be made in the non-system opex proposed by Western Power unless Western Power can demonstrate that it will identify and make payment to all customers eligible to receive an extended outage payment. This expenditure relates to the distribution business and the adjustment should be applied accordingly. The adjustment is shown in the table in section 9.5.

We consider the remaining business support opex proposed for the next period reasonable without adjustment, as we consider that Western Power had justified the forecast expenditure and in particular the reasons for the increase from the level in the present period - *viz.* the expected increases in the real cost of labour, increased resources to support larger capex and opex work programmes, new initiatives to improve workforce capability and planning, strategic initiatives to improve business performance and customer and community interaction and increases in other costs such as insurance.

8 Transmission Opex

8.1 Expenditure in Present period

Table 8.1 shows that Western Power's transmission opex is projected to be $205 m over the present period, $2 m or 1% below the total approved for the period (all figures expressed in 2006 dollars).

Table 8.1: Transmission Opex in Present period *vs*. Approved Level ($ 2006 m)

	Approved AA1				Actual/Forecast AA1				
YE 30 June	2007	2008	2009	Total	2007	2008	2009	Total	Diff
Operations	19	20	20	**59**	22	23	18	**64**	+ 8%
Maintenance	25	24	25	**74**	29	27	26	**83**	+ 11%
Business Support	23	25	25	**73**	17	19	22	**58**	- 21%
Other	0	0	0	**0**	0	0	1	**1**	n/a
Total	**67**	**69**	**70**	**207**	**68**	**69**	**68**	**205**	**- 1%**

Source: Western Power.

Operations and maintenance costs were higher than the approved levels whilst, for the reasons explained in section 7.2, business support costs were lower. The higher operations and maintenance costs were due to the reallocation of some business support costs, real cost increases in material and labour costs and some modest additions to the programme to address identified risks such as asbestos in buildings.

Western Power said that over the period there had been an increase in the backlog of corrective maintenance work identified from inspection programmes, particularly overhead lines and substation plant.

8.2 Proposed Expenditure in Next Period

Western Power's proposed transmission opex in the next period compared with that in the present period is shown in Table 8.2.

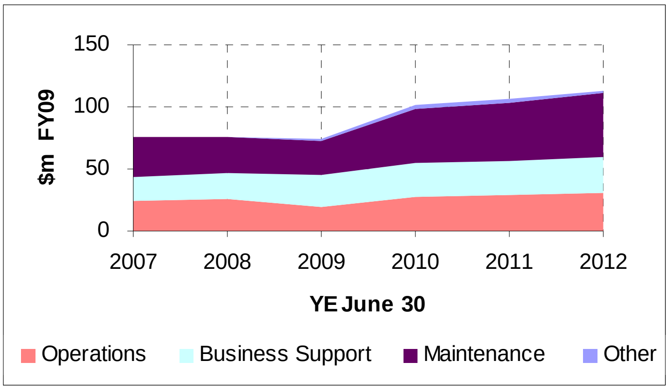
Table 8.2: Current and Forecast Transmission Opex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast		Proposed				
YE 30 June	2007	2008	2009	Total	2010	2011	2012	Total	Diff
Operations	24	25	20	**70**	27	29	31	**86**	+ 24%
Maintenance	32	30	29	**91**	44	47	52	**143**	+ 58%
Business Support	19	21	24	**63**	27	28	29	**84**	+ 33%
Other	0	0	1	**1**	2	2	2	**6**	+ 348%
Total	**75**	**76**	**75**	**225**	**101**	**106**	**113**	**320**	**+ 42%**

Source: Western Power.

The total opex proposed in the next period is $320 m, compared with an estimated $225 m in the present period, an increase of 42%. All categories of expenditure are projected to rise in the next period with the highest increase being in maintenance activity. Figure 8.1 shows the trend in expenditure.

Figure 8.1: Trend in Transmission Opex ($ 2009 m)



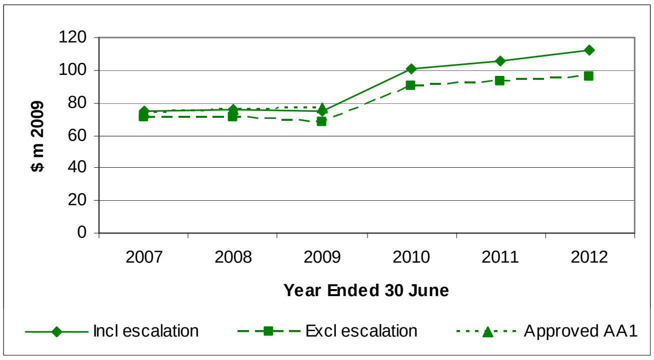
Western Power said that the proposed transmission opex increases are principally driven by the impact of network growth and new connections for load and generation, the ongoing impact of previously constrained expenditure and the continuing increase in unit costs, particularly in light of the resources boom in Western Australia. [82]

The growing asset base means an increase in the volume of inspections and operational work during the next period. Western Power said the increase in forecast opex relates primarily to the cost of employing more technicians to manage and maintain the additional assets but the growth in operating expenditure is moderated by asset condition monitoring improvements and asset replacements. Transmission SCADA and communications costs will also increase as the size of the network grows.

The need to address the backlog of preventive maintenance and projected cost escalation are other factors, as already mentioned in this report.

We analysed the effects of cost escalation to determine the cost variance attributable to it in Western Power's transmission opex for the next period. The method used was that described on p. 35 of this report under the heading "Impact of Cost Escalation". The impact of removing cost escalation from the expenditure projections is shown in Figure 8.2 and Table 8.3.

Figure 8.2: Impact of Cost Escalation in Next Period ($ 2009 m)



The table shows that escalation is forecast to increase the cost of work undertaken in the present period by 7% and of that undertaken in the next period by 15%. It also shows that of the total increase in expenditure in the next period of 42% over the present period (in year 2009 dollars), 10 percentage points are attributable to escalation in costs, the balance being attributable to volume variances or other factors.

[82] The projections were prepared prior to October 2008.

Table 8.3: Impact of Cost Escalation in Next Period ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Total with escalation	75	76	75	**225**	101	106	113	**320**	+ 42%
Total w/o escalation	71	71	68	**210**	90	93	96	**278**	+ 32%
Diff due to escalation	6%	6%	10%	**7%**	12%	14%	17%	**15%**	

8.3 Review by Category ("Bottom-Up" Analysis)

Operational Expenditure

Table 8.4 shows current and forecast transmission operations expenditure for the present and next periods.

Table 8.4: Current and Forecast Operational Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
SCADA & Comms	7	7	6	**20**	8	9	10	**27**	+ 34%
Misc Network Services	11	5	4	**21**	6	6	6	**18**	- 15%
Network Operations	7	13	10	**29**	13	14	15	**42**	+ 44%
Total	**24**	**25**	**20**	**70**	**27**	**29**	**31**	**86**	**+ 24%**

Source: Western Power.

Expenditure in the next period is projected to be $86 m, compared with $70 m in the present period, an increase of 24%. Operations costs account for approximately 27% of Western Power's total transmission opex for the next period.

SCADA and communications costs relate to the management and maintenance of SCADA and communications equipment. Western Power states that the cost increases are due to the increasing number of assets being managed and increased functionality in the system.

Miscellaneous network services, which are also referred to as non-reference services, are services for which Western Power recovers costs from third parties through charges rather than tariffs. They include such items as the need to relocate assets due to developments. Forecast expenditure is consistent with expenditure in recent years and we note that forecast revenue from non-reference services in the revenue model is also at a similar level to the expenditure proposed. [83]

Network operations expenditure covers the cost of providing the system operations centre and managing the SCADA master station. The reasons stated for the increase in these costs relate to the increased volume of switching required to support the larger works programme and the transfer of SCADA service costs that were previously allocated to customer services.

We were satisfied that the forecast expenditure in this category in the next period is reasonable for the following reasons.

- The expenditure is generally of a predictable and recurring nature and past expenditure provide a sound basis for forecasting it.

[83] Source: Appendix 7 to the *Access arrangement information*.

- The increases in expenditure from the present period can be explained by increases in the real cost of labour and increases in the volume of activity expected from the increased work programme in the next period and the increase in assets managed and maintained.

Maintenance Expenditure

Policies and Practices

Western Power's maintenance philosophy and practices are outlined in its transmission asset management plans. [84] We reviewed the plans and found they reflected typical practice in the electricity transmission industry in Australasia. However, we noted that Western Power has recently completed a review of its maintenance activities and determined that only 60% of the maintenance activity specified in its plant manuals is presently being carried out. Policies and manuals are effective only if they are put into practice and we would not consider that an achievement of only 60% of recommended routine maintenance represents prudent practice.

Proposed Expenditure

Table 8.5 shows current and forecast maintenance expenditure in the present and next periods.

Table 8.5: Current and Forecast Maintenance Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Maintenance Strategy	6	4	0	**10**	0	0	0	**0**	- 100%
Preventive Condition	9	7	10	**27**	14	15	17	**46**	+ 74%
Preventive Routine	12	12	12	**36**	21	23	24	**68**	+ 91%
Corrective Deferred	3	5	4	**13**	6	7	7	**19**	+ 53%
Corrective Emergency	2	2	2	**5**	3	3	3	**10**	+ 78%
Total	**32**	**30**	**29**	**91**	**44**	**47**	**52**	**143**	**+ 58%**

Source: Western Power.

Expenditure in the next period is forecast to be $143 m, compared with $91 m in the present period, an increase of 58%. Maintenance costs account for approximately 45% of Western Power's total transmission opex for the next period.

Expenditure under the maintenance strategy category, separately recorded in the first two years of the present period, constitutes indirect costs and is now allocated to work programmes as described in section 7.2.

Preventive Maintenance

Preventive routine maintenance is carried out to reduce the probability of failure of an asset and consists of follow-up activities to address conditions or defects identified through routine maintenance activities.

As noted above, Western Power has determined that only 60% of its specified maintenance activity is presently being carried out. We also note that the incidence of catastrophic failure of major plant items is above industry norms, something that is likely to be a direct consequence of inadequate preventive maintenance on these assets. Much of the deferred maintenance relates to critical system plant items, transformers and switchgear, failure of

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[84] Document DMS#: 906804v14, *"SWIS transmission network asset management plan 2008/2009 to 2017-2018"*, June 2008.

which results in major impacts on system reliability. Achievement of only 60% of recommended maintenance activities cannot be considered to represent good industry practice or one that a prudent operator would target.

The biggest increase in proposed expenditure to bring these activities up to acceptable levels is in the maintenance of primary plant items such as transformers and circuit breakers. Other additional or activities include the treatment of insulators with silicon, more line patrols, building maintenance and secondary plant maintenance. The increased growth in asset numbers stemming from the large capital works programme contributes to the increase in maintenance work.

We were advised that despite the forecast increase in expenditure, the desired programme in the next period had been curtailed by approximately $10 m because of foreseen deliverability constraints.

Preventive maintenance, particularly for major and critical plant items, is a cornerstone of sound asset management and important to efficiently minimise life cycle costs. We consider that the increased expenditure on preventive maintenance is justified – and overdue.

Corrective Maintenance

Corrective maintenance includes corrective deferred and corrective emergency maintenance. Corrective deferred maintenance includes the repair of failed or damaged equipment that does not entail an emergency. Such work usually follows emergency restoration of supply, where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the work or rebuild the assets later.

Corrective emergency maintenance includes maintenance activities carried out with urgency to restore supply or make a site safe following a failure – usually because of an accident, equipment failure or bad weather. The need for this type of work generally occurs without warning and is performed immediately to restore supply, ensure safety and prevent further damage to equipment.

Western Power states that its corrective maintenance forecasts for the next period have been developed by applying linear regression analyses to historical data. The methodology implies that the impact of the proposed additional preventive maintenance will not be significant until after the end of the next period. Western Power states that it believes that this is a reasonable proposition, as the lag between increasing maintenance and reduced unplanned or unassisted asset failures is usually several years.

We were concerned with two aspects of this methodology. First, when the impact of real cost increases is removed, the data does not indicate a rising trend in expenditure. Second, whilst it may be reasonable to assume that the fault rate will not respond immediately it is a different matter to assume that the fault rate will continue to increase.

We consider that the increase in preventive maintenance expenditure, combined with the proposed increase in replacement capex, will have an impact on the number of unplanned equipment faults. We consider that it is more reasonable to assume that the fault rate (and therefore corrective expenditure) will, at the least, be stabilised. We thus consider that the forecast of corrective maintenance expenditure is overstated for the next period and should be reduced. We propose that the level of corrective maintenance for the next period should be the average of the expenditure in the present period adjusted for cost escalation. The calculation of the level and the required reduction is shown in Table 8.6.

Table 8.6: Adjustment to Corrective Maintenance Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Proposed by W Pwr	5.2	6.7	6.3	**18.2**	8.7	9.8	10.6	**29.1**	+ 60%
Remove escalation	(0.3)	(0.4)	(0.6)	**(1.2)**	(1.0)	(1.2)	(1.6)	**(3.8)**	
	4.9	6.3	5.8	**16.9**	7.7	8.6	9.1	**25.4**	+ 50%
Recommended base					5.6	5.6	5.6	**16.9**	
Add back escalation					0.7	0.8	1.0	**2.5**	
					6.3	6.5	6.6	**19.4**	+ 7%
Adjustment					**(2.4)**	**(3.3)**	**(4.0)**	**(9.7)**	

Efficiency of Maintenance Expenditure

We would expect that a network operator seeking to minimise costs efficiently would have a maintenance regime that:

- gathered condition information on its assets;
- targeted and prioritised preventive maintenance activities based on identified condition defects and the risks a particular asset posed in terms of safety and system reliability and security;
- undertook sufficient preventive maintenance to minimise the costs and customer inconvenience of corrective or reactive maintenance; and
- undertook the planning, scheduling and execution of those maintenance activities in a cost-effective manner.

Western Power has acknowledged that it is still building its asset condition information data to an appropriate level and it has historically has under-spent on inspection, monitoring and preventive work on its assets. This has led to asset failure rates above industry norms and a high level of corrective maintenance expenditure.

We consider that it is prudent and efficient for Western Power to target a higher level of preventive maintenance and associated replacement capex expenditure as this will lead to future reductions in the level of corrective maintenance required and to improvements in reliability of supply.

We note that Western Power has also instituted a risk-management-based approach to prioritise its opex and its capex. This should ensure that it achieves the best outcomes for the expenditure made.

We also note that Western Power has introduced several strategies and initiatives to enable its works programme to be delivered and we note that the transmission opex component will be delivered primarily by internal resources with some contractor support.

Summary of Maintenance Expenditure

Western Power has appropriate transmission maintenance policies but resource constraints have meant that these policies have not been applied adequately in the present period. We agree that an increase in preventive maintenance is required and consider for the purposes of this review that the forecast level of expenditure in that area is reasonable. However, we consider that the forecast level of expenditure on corrective maintenance is overstated and propose an adjustment of $ 9.7 m as shown in Table 8.6 above.

Business Support Expenditure

Thirty-three per cent of the business support expenditure reviewed and considered reasonable in section 7.2 is allocated to transmission opex. Expenditure in the next period is $84 m compared to $63m in the present period, an increase of 33% and business support accounts for approximately 26% of Western Power's total transmission opex for the next period.

Other Expenditure

Other expenditure in the next period is $6 m compared with $1 m in the present period and accounts for approximately 2% of Western Power's total transmission opex for the next period. The expenditure relates to two items, operational costs associated with the presence of asbestos in substations and the removal of redundant assets. [85] We consider this expenditure reasonable, as the first is a safety- and regulatory-related requirement and the second is needed to reinstate easements and recover stranded assets.

Summary of Review by Category

Our review of the expenditure by category has identified one adjustment to the proposed transmission opex in the next period as shown in Table 8.7.

Table 8.7: Recommended Adjustments to Proposed Opex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Proposed by W Pwr	75	76	75	**225**	101	106	113	**320**	+ 42%
Corrective mtce					(2)	(3)	(4)	**(10)**	
					(2)	(3)	(4)	**(10)**	
Recommended Level					**99**	**103**	**109**	**310**	**+ 38%**

8.4 Efficiency of Overall Expenditure ("Top-Down" Analysis)

As a check of the overall level of transmission opex, we compared Western Power's controllable transmission opex with that of selected transmission network service providers in other Australian states. [86] We noted that Western Power includes sub-transmission in its transmission category whereas the other entities in the comparison exclude it, as it is a function of the distribution businesses in those states. [87] We therefore adjusted Western Power's opex to remove sub-transmission costs from the analysis. [88]

Data for the entities in other states was extracted from publicly available sources. [89] Figure 8.3 shows the comparison of Western Power's projected transmission opex with that of the other transmission system operators in the comparison, based on cost per line length for FY 2008 and FY 2010.

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85 Capital expenditure is allowed for the removal of asbestos risks categorized as high and medium but low risk installations will not be removed in the next period. Thus, some operational costs to manage the situation are expected.

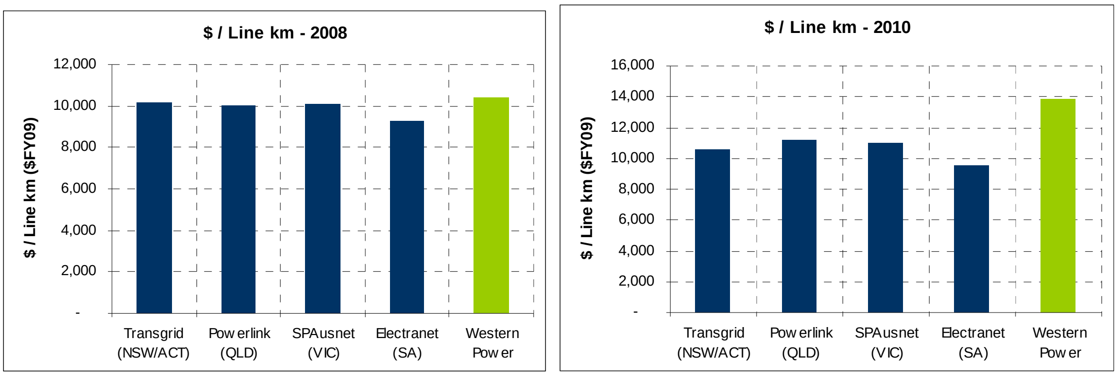
86 Our terms of reference asked us to consider benchmarking, where possible.

87 The matter is not straightforward, as the electricity supply industry in Western Australia is still vertically integrated (at least in relation to the network) but in other states, transmission and distribution are carried out by separate entities.

88 In discussion with Western Power, the sub-transmission component was estimated to account for 60% of transmission opex.

89 Determinations and submissions relating to TransGrid, SP Ausnet, Powerlink and Electranet taken from the AER's website and statistical data taken from AER's publication *State of the energy market*, also available on its website.

Figure 8.3: Comparison of Transmission Opex with Other States



Observations and Conclusion

The analysis shows in relation to FY 2008 expenditure levels that Western Power had levels of opex similar to those in the other businesses.

Given the differences in Western Power's circumstances vis-à-vis the businesses in the other states, the usual uncertainties inherent in benchmarking (especially in relation to any network business serving a predominantly rural area) and uncertainty about the likely levels of opex that will be agreed to in the present round of regulatory reviews, we concluded that we should not rely on this analysis when forming our opinion, other than as a general check of reasonableness of the overall level of our proposed opex.

8.5 Recommended Level of Expenditure

Having considered the factors reported in this section, we conclude for the purpose of this review that a reduction of $10 m p.a. should be made in Western Power's proposed transmission opex as shown in Table 8.7 above.

9 Distribution Opex

9.1 Expenditure in Current Period

Table 9.1 shows that Western Power’s distribution opex is projected to be $577 m over the present period, representing a total expenditure that is $131 m or 23% above the total approved for the period (all figures expressed in 2006 dollars).

Table 9.1: Distribution Opex in Current Period *vs*. Approved Level ($ 2006 m)

YE 30 June	Approved AA1				Actual/Forecast AA1				Diff
	2007	2008	2009	Total	2007	2008	2009	Total	
Operations	14	15	15	**44**	21	18	20	**59**	+ 36%
Maintenance	97	94	91	**282**	144	146	139	**429**	+ 52%
Customer and Billing	20	20	21	**62**	24	22	20	**66**	+ 7%
Business Support	59	63	68	**190**	43	50	60	**153**	- 19%
Other	0	0	0	**0**	0	0	0	**0**	n/a
Total	**190**	**192**	**195**	**577**	**232**	**236**	**239**	**708**	**+ 23%**

Source: Western Power.

Operations and maintenance costs were higher than the approved level whilst, for the reasons explained in section 7.2, business support costs were lower. Customer and billing costs are forecast to be a little over the approved level for the period.

The largest increase in both quantum and percentage terms is in maintenance expenditure. Western Power states that the increased expenditure is the result of its strategy to align inspection and maintenance work with its distribution asset mission statements. It says that constrained expenditures have resulted in only the highest priority inspection and maintenance work being implemented and that is one of the causes of less-than-optimal network reliability performance, high levels of corrective maintenance and a significant number of asset failures. Western Power’s states that it has committed considerable additional distribution opex above the regulatory allowances during the current period to help address these issues.

The higher operational costs are said to be due to the need to provide network control support for the higher-than-anticipated capex and opex programmes in the period. Other cost impacts arose from real cost increases in material and labour, partially offset by the reallocation of some business support costs,

We analysed the effects of cost escalation to determine the cost variance attributable to it in Western Power’s distribution opex in the present period. The method used was that described on p. 35 of this report under the heading “Impact of Cost Escalation”. The effect of removing inflation from the expenditure projections is shown in Table 9.2. The table shows that escalation is forecast to increase the cost of work undertaken in the present period by 6% and that of the total increase in expenditure in the period of 23% (in year 2006 dollar terms), 6 percentage points are attributable to escalation in costs with the balance being attributable to volume variances or other factors.

Table 9.2: Impact of Cost Escalation in Present Period ($ 2006 m)

	Present Period (AA1)			
	Actual		Forecast	Total
YE 30 June	2007	2008	2009	
Approved AA1	190	192	195	**577**
Actual with escalation	232	236	239	**708**
Actual w/o escalation	223	226	221	**671**
Diff due to escalation	4%	4%	8%	**6%**

9.2 Proposed Expenditure in Next Period

Western Power's proposed distribution opex in the next period compared with that in the present period is shown in Table 9.3.

Table 9.3: Current and Forecast Distribution Opex ($ 2009 m)

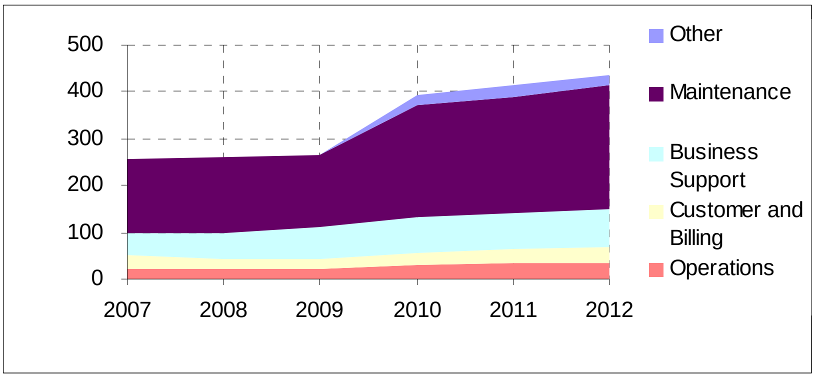
	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Operations	23	20	22	**65**	30	33	36	**99**	+ 52%
Maintenance	158	160	153	**471**	240	249	262	**751**	+ 59%
Customer and Billing	26	24	22	**73**	26	30	35	**90**	+ 24%
Business Support	47	55	66	**168**	77	79	81	**236**	+ 40%
Other	0	0	0	**0**	22	25	23	**71**	n/a
Total	**255**	**260**	**263**	**777**	**394**	**416**	**436**	**1,247**	**+ 60%**

Source: Western Power.

The total opex proposed in the next period is $1,247 m compared with an estimated $777 m in the present period, an increase of 60%. Western Power has stated that the reasons for the increased level of expenditure include: increased workload largely arising from the increased quantity of assets, continuing cost increases above the rate of inflation, particularly for labour; significant additions and enhancements to the maintenance programme; and provision of additional generators to maintain supply during prolonged planned outages.

Figure 9.1 shows the trend of expenditure from FY 2007 to FY 2012.

Figure 9.1: Trend in Distribution Opex ($ 2009 m)



The graph shows a rising trend in the all the main expenditure categories and a large proposed step increase in maintenance expenditure from the last year of the present period to the first year of the next period.

We analysed the effects of cost escalation to determine the cost variance attributable to it in Western Power's distribution opex for the next period. The method used was that described on p. 35 of this report under the heading "Impact of Cost Escalation". The effect of removing inflation from the expenditure projections is shown in Figure 9.2 and Table 9.4.

Figure 9.2: Impact of Cost Escalation in Next Period ($ 2009 m)

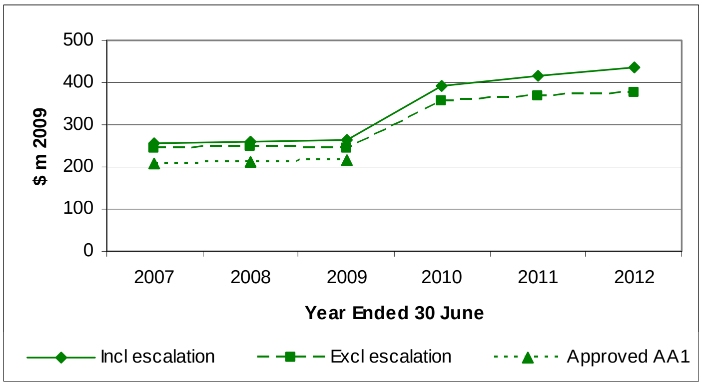


Table 9.4: Impact of Cost Escalation in Next Period ($ 2009 m)

YE 30 June	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
	2007	2008	2009		2010	2011	2012		
Total with escalation	255	260	263	**777**	394	416	436	**1,247**	+ 60%
Total w/o escalation	245	249	243	**737**	355	369	377	**1,102**	+ 50%
Diff due to escalation	4%	4%	8%	**6%**	11%	13%	16%	**13%**	

The table shows that escalation is forecast to increase the cost of work undertaken in the present period by 6% and of that undertaken in the next period by 13%. It also shows that of the total increase in expenditure in the next period of 60% over the present period (in year 2009 dollars), 10 percentage points are attributable to escalation in costs, the balance being attributable to volume variances or other factors.

9.3 Review by Category ("Bottom-Up" Analysis)

Operational Expenditure

Table 9.5 shows current and forecast distribution operations expenditure for the present and next periods.

Table 9.5: Current and Forecast Operational Expenditure ($ 2009 m)

YE 30 June	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
	2007	2008	2009		2010	2011	2012		
Reliability	4	2	2	**7**	1	1	1	**3**	- 55%
SCADA & Comms	1	1	1	**4**	1	1	2	**4**	+ 19%
Misc Network Services	5	6	5	**16**	7	9	10	**26**	+ 59%
Network Operations	13	11	14	**38**	20	22	23	**65**	+ 72%
Total	**23**	**20**	**22**	**65**	**30**	**33**	**36**	**99**	**+ 52%**

Source: Western Power.

Expenditure in the next period is $99 m compared with $65 m in the present period, an increase of 52%. Operations costs account for approximately 8% of Western Power's total distribution opex for the next period.

Expenditure focussed on reliability improvement is forecast to decline in the next period because this expenditure is being increasingly incorporated in the planned maintenance programme.

The principal cost increases in SCADA and communications are said to be due to the increasing number of assets being managed because of the capital works programme and increased functionality being incorporated into the system.

Forecast expenditure on miscellaneous network services in the next period is 59% above the level expected for the present period. The increase is said to be due to an increasing demand for theses services. We note that the revenue forecast from non-reference services in the revenue model is approximately $9 m less than the expenditure proposed under this category, suggesting that either some of the expenditure should be re-categorised to be included in reference services or that the revenue forecast for non-reference services is incorrect. [90]

Network operations expenditure covers the costs of providing the network operations control centre, which plans and directs switching on the distribution network. The cost of managing the SCADA master station is included in this category. The reasons for the increase in these costs relate to the increased volume of switching required to support the larger works programme and the transfer of SCADA service costs that were previously allocated to customer services. Switching requests processed by the control centre nearly doubled between 2006 and 2008 and are expected to keep increasing in the next period because of the large capital and maintenance works programmes. Extra costs also arose from the centralisation of switching activities. The forecast for the next period also includes extra expenditure on diesel fuel for peak-lopping generators deployed on the edges of the network.

We were satisfied that the forecast expenditure in this category for the next period is reasonable for the following reasons.

- The expenditure in these categories is generally of a predictable and recurring nature and past expenditure provides a sound basis for forecasting future expenditure.
- The increases in expenditure from the level in the present period can be explained by increases in the real cost of labour and increases in the volume of activity expected from the increased work programme in the next period and the increase in assets managed and maintained.

Maintenance Expenditure

Maintenance Policies and Practices

Western Power's maintenance philosophy and practices for its distribution assets are outlined in its distribution asset management plan and asset mission statements. We reviewed the distribution asset management plan and a sample of the asset missions and found that whilst they generally reflected typical practice in the electricity distribution industry in Australasia, the asset maintenance processes were at a less sophisticated level than those of other distributors. We also noted that Western Power has recently completed a review of its distribution maintenance activities and determined that it is not achieving the level of maintenance activity recommended for its assets.

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90 See Appendix 7 of the *Access arrangement information.*

Run-to-Failure Assets

We noted in section 8 of the distribution asset management plan that Western Power runs a number of assets to failure: that is, the assets are replaced only when they fail and are not subject to preventive maintenance. It is typical industry practice to do this for smaller assets but we consider that Western Power has a number of larger assets, e.g. ring main units and transformers under 300 kVA, which would normally be included in an inspection and condition monitoring process. We also note that the replacement cost of all run-to-failure assets is expensed, whereas we would have expected larger items to be capitalised. [91]

Proposed Maintenance Expenditure

Table 9.6 shows current and forecast network maintenance expenditure for the present and next periods.

Table 9.6: Current and Forecast Maintenance Expenditure ($ m 2009)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Maintenance Strategy	10	9	0	**18**	0	0	0	**0**	- 100%
Preventive Condition	36	32	50	**117**	91	93	96	**280**	+ 140%
Preventive Routine	29	31	32	**92**	54	56	59	**170**	+ 85%
Corrective Deferred	28	28	23	**79**	23	26	28	**77**	- 1%
Corrective Emergency	57	60	49	**166**	71	74	78	**224**	+ 35%
Total	**158**	**160**	**153**	**471**	**240**	**249**	**262**	**751**	**+ 59%**

Source: Western Power.

Expenditure in the next period is forecast to be $751 m compared with $471 m in the present period, an increase of 59%. Maintenance costs account for approximately 60% of Western Power's total distribution opex for the next period. Expenditure under the maintenance strategy category separately recorded in the first two years of the present period is now allocated to works programmes as described in section 7.2.

Preventive Maintenance

Preventive maintenance consists of routine maintenance carried out to reduce the probability of failure of an asset and condition maintenance is follow-up activities to address conditions or defects identified through routine maintenance activities. Western Power has recently completed a review of its maintenance activities and is proposing a substantial increase in both preventive routine and preventive condition maintenance. The growth in asset numbers resulting from the large capital works programme also contributes to the increase.

Preventive Routine Maintenance

Western Power states that the major changes planned in its preventive routine maintenance programme are:

- ***Power Pole Inspections***. It is to combine ground line inspection and treatment with above-ground pole and line inspections. Ground line inspection will be enhanced to include excavation to 500 mm. This will increase pole inspection costs by an average of $11.5 m p.a. over the next period.

[91] Some other items covered by the run-to-failure strategy appear to be out of place as well. For example, overhead disconnectors are usually managed on condition and not run to failure because when a switch needs to be opened or closed, the operator wants it to find it in an operational state to prevent extending outage minutes. Replacing such assets on failure may also not be efficient. It would be more normal to plot the failure rates of such assets and take corrective action as required.

- ***Substation Bundled Inspections***. Budgetary constraints have resulted in only minimal inspections and maintenance of ground mounted substations. An enhanced programme is proposed for the next period. This will result in additional expenditure of an average of $11.7 m p.a. over the next period.
- ***Metal Pole Inspections***. This activity covers inspection of metal power poles and street lighting poles and will result in additional expenditure averaging $4.0 m p.a. over the next period.
- ***Bulk Lamp Replacement.*** A 3-year bulk lamp replacement programme has been introduced. Costs will be slightly higher but more efficient due to fewer fault repairs, the effect of which will be realised after the first 3-year cycle has been completed with fewer lamp outages and improved safety and compliance. This will result in average expenditure of $3.3 m p.a. over the next period. [92]

These additional costs are offset by reductions in activities that have been superseded by the new programmes. The reductions amount to $4.6 m p.a.

We consider that the increased expenditure is prudent and justified in scope. The proposed level of work is based on recognised practice for plant of this nature and will provide Western Power with much better condition-based data on which to base both maintenance and replacement decisions. The costs have been estimated using known quantities and contract rates or historically based unit rates.

Preventive Condition Maintenance

Western Power states that the major changes to its preventive condition maintenance programme are:

- ***Pole Maintenance***. Additional remedial work is expected to result from the new inspection regime. Recent inspection condition data has been used to predict the quantity of remedial work required in the next period. Combined with cost increases, the additional expenditure will average $14.6 m p.a. over the next period.
- ***Vegetation Management***. Enhancements have been made to the vegetation management process, including reducing the moderate fire risk zone vegetation inspection cycle from three years to two. This will result in additional average expenditure of $13.0 m p.a. over the next period.
- ***Emergency Response Generators***. Emergency response generators are used to maintain supply during lengthy planned outages. As well as its own generators, Western Power plans to hire an additional 16 over the summer. It is planned to deploy generators on an additional 400 maintenance events each year. This will result in additional expenditure of an average of $6.6 m p.a. over the next period. This equates to $16,750 per event.
- ***Other, including Backlog.*** Western Power has a backlog of conditions outstanding from the present period that will be carried over into the next. Backlogs are now collated by areas and combined with new defects found from inspection programmes, resulting in labour and plant cost efficiencies. Additional expenditure to address the maintenance backlog of $20.2 m p.a. on average is proposed over the next period.

Western Power provided us with information that showed that the backlog of identified conditions requiring attention had tripled between FY 2006 and FY 2008. We were also provided with data that showed that the number of overhead line faults per 100 km of line

[92] Most other distribution businesses already follow this practice.

due to equipment failure had doubled in the same period. [93] This showed that the more extensive inspection programme was identifying condition defects and that failure to keep up with remedial work was resulting in higher failure rates of equipment. This supported Western Power's intention to increase expenditure on addressing both an increasing level of identified defects and also to address the backlog of defects already identified. On this basis, we agreed that the increased expenditure is required. Given the shortfall over many years in maintenance activity, this increased level of activity can be expected to continue for a number of years and will result in improved safety and reliability outcomes. Costs have been estimated based on experience and known rates.

Rate of Increase in Expenditure

The quantum of increased expenditure in this category is large, 140% over the period, and will be challenging for Western Power in terms of planning, scheduling and delivery. We doubt its ability to ramp up the level of activity as quickly as it proposes, due to the large increase required in the internal staff and contracting resources. Central to this view is the fact that preventive maintenance on distribution networks, with their myriad of small components, is labour-intensive. The large increase projected will require considerable resources for the management and direction of the programme and for auditing its output. This, combined with the degree of cultural change being implemented in the organisation, may be beyond Western Power's means. We consider that a more gradual increase in work levels would be prudent, giving time for the systems, processes and resources to be put in place to achieve the outputs in a more efficient manner.

We therefore recommend that expenditure in the first year of the next period be reduced to the mid point between the forecast FY 2009 and the proposed FY 2011 levels, which will give a staged uplift over two years instead of one, a level we consider more realistic to achieve. This results in a reduction of $21 m in the first year of the next period.

Corrective Maintenance

Western Power's corrective maintenance forecasts for the next period have been developed using the same methodology as that discussed in section 8.3 under the heading "Corrective Maintenance". For the reasons expressed in that section, we consider that the forecast of expenditure under this heading is overstated for the next period and should be reduced. As in section 8.3, the recommended level for the next period has been based on the average expenditure in the present period, adjusted for cost escalation. The calculation is shown in Table 9.7.

Table 9.7: Adjustment in Corrective Maintenance Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				Diff
	Actual		Forecast	Total	Proposed			Total	
YE 30 June	2007	2008	2009		2010	2011	2012		
Proposed by W Pwr	84.2	88.6	71.7	**244.4**	94.4	100.0	106.9	**301.3**	+ 23%
Remove escalation	(3.2)	(3.7)	(5.5)	**(12.4)**	(9.3)	(11.3)	(14.5)	**(35.1)**	
	81.0	84.8	66.1	**231.9**	85.1	88.7	92.3	**266.1**	+ 15%
Recommended base					77.3	77.3	77.3	**231.9**	
Add back escalation					8.4	9.8	12.2	**30.5**	
					85.8	87.2	89.5	**262.4**	+ 7%
Adjustment					**(8.6)**	**(12.9)**	**(17.4)**	**(38.9)**	

93 See graphs in section 3.2, p. 16.

Efficiency of Maintenance Expenditure

We outlined in section 8.3 under the heading "Efficiency of Maintenance Expenditure" the maintenance regime that we would expect to see a prudent transmission network operator adopt and we noted that Western Power has acknowledged that it is still building its asset condition information data to an appropriate level and that it has historically under-spent on inspection, monitoring and the preventive maintenance of its assets.

The same principles apply to distribution maintenance. In distribution, the number of assets involved are much larger and Western Power acknowledges that the gap between recommended practice and its historical performance is greater than for transmission.

We consider it prudent and efficient for Western Power to target a higher level of preventive maintenance and associated replacement capex expenditure. This will lead to future reductions in the level of corrective maintenance required and to improvements in reliability and public safety.

We note that Western Power has also instituted a risk-management-based approach to prioritise its opex and its capex. This should ensure that it achieves the best outcomes for the expenditure made.

We also note that Western Power has initiated several strategies and initiatives to enable its works programme to be delivered and that the distribution opex component will be delivered by a mix of internal resources and external contractors. Contractors will operate in allocated regions with Western Power's own workforce operating in all regions. Western Power plans to increase the use of performance-based contracts, replacing its "preferred vendor" strategy to maintain a balance between competitive price-and-performance tensions on the one hand and maintaining a flow of work to underpin the viability of the contracting model on the other. The proposed mix of internal delivery and contract delivery for specialist and routine activities such as inspection and vegetation management is common practice in the industry.

Summary

In summary, Western Power is proposing significant changes to its distribution maintenance practices. It intends placing a much greater emphasis on preventive maintenance, based on more robust condition assessment. This is expected to increase the amount of condition-driven maintenance work and should help address the problems caused by curtailed expenditure in this area over recent years.

In that context, we agree that an increase in preventive maintenance expenditure is required but we have reservations as to whether Western Power can ramp up this activity to the proposed level efficiently in the first year of the next period.

In addition, we consider that the increased emphasis on preventive maintenance, together with the proposed increase in capital expenditure on asset replacement, should, over time, lead to a reduction in corrective maintenance. Thus, the level of corrective maintenance should not continue to increase. We consider that for the next period, it should stabilise at around present levels and then decline in later periods.

Accordingly, we have proposed adjustments to both preventive and corrective maintenance.

Customer and Billing Expenditure

Table 9.8 shows current and forecast customer and billing expenditure for the current and next period. Expenditure in the next period is $90 m compared with $73 m in the present period, an increase of 24%. Customer and billing costs account for approximately 28% of Western Power's total distribution opex for the period.

Table 9.8: Current and Forecast Customer and Billing Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Call Centre	5	5	6	**17**	5	5	6	**16**	- 2%
Metering	21	19	16	**56**	20	24	29	**74**	+ 31%
Total	**26**	**24**	**22**	**73**	**26**	**30**	**35**	**90**	**+ 24%**

Source: Western Power.

Call centre costs are at a similar level to the present period. A change in delivery of this service will occur with the transfer of the service from the incumbent retailer to Western Power's own resources.

Metering costs are forecast to increase by 31% in the next period. We were advised by Western Power that the increase is due primarily to the inclusion $22 m for smart meter processing. This should not have been included, as smart metering has not been included in the proposal for the next period. [94] The proposed opex for the period should therefore be reduced by this amount.

Business Support Expenditure

Sixty-seven per cent of the business support expenditure reviewed in section 7.2 above is allocated to distribution opex. Expenditure in the next period is $236 m compared to $168 m in the present period, an increase of 40%. Business support costs account for approximately 19% of Western Power's total transmission opex for the next period.

As outlined in section 7.2, we do not consider that Western Power should be provided with revenue to cover extended outage payments for all eligible customers unless it has a process in place to ensure all the payments are made. An adjustment to remove this is recommended.

Other Expenditure

Western Power has proposed spending $71 m on five non-recurring programmes in the next period. Collectively, they account for 6% of the proposed opex. Details are shown in Table 9.9.

Table 9.9: Current and Forecast Other Expenditure ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Demand Side Mgmt	0	0	0	**0**	5	3	1	**10**	n/a
Field Survey	0	0	0	**0**	2	6	6	**14**	n/a
Training	0	0	0	**0**	10	10	10	**30**	n/a
DA Seq Switching	0	0	0	**0**	0	0	0	**0**	n/a
Energy Solutions	0	0	0	**0**	5	6	6	**17**	n/a
Total	**0**	**0**	**0**	**0**	**22**	**25**	**23**	**71**	**n/a**

Source: Western Power.

Demand Management

Western Power is required to consider alternative options in the development of network capacity augmentation plans. It is proposing to undertake ten demand management trial and investigation projects during the next period to build up its knowledge of their effectiveness

[94] See section 4.1.

and associated implementation costs. This will provide network planners with better information upon which to analyse the viability of DSM options in the future. We consider that the expenditure is reasonable and potentially could lead to reduced or deferred capex in the future.

Field Survey

The field survey project is aimed at verifying data quality problems. We consider that the work is reasonable, as it will improve the quality of Western Power's asset information.

Training

Training of internal staff and contractors includes ongoing refresher and safety courses as well as the certification of new trainees. About 70% of the costs relate to external contractors and 30% to new Western Power staff. Training costs are expected to be higher in the next period due to the large increase planned in the workforce. These costs have not previously been budgeted for separately but Western Power did provide us with a breakdown of costs in the present period. The estimate is based on expected demand in the next period and we consider it reasonable.

Distribution Switching Initiative

The distribution automation switching initiative is immaterial in terms of the total expenditure but relates to the preparation of automatic switching scripts to improve reliability. The expenditure is reasonable and could have been included under operational expenditure rather than being identified separately.

Energy Solutions

The energy solutions expenditure is investigatory, to see how Western Power can benefit from the installation of improved intelligence and communication capability inherent in new meters and SCADA and communications investment to reduce or defer capex through initiatives such as peak load reduction, distributed generation or improved network operation. We consider that the expenditure is reasonable, as it is an investment in potential future efficiency improvement.

9.4 Efficiency of Overall Expenditure ("Top-Down" Analysis)

As a check of Western Power's overall level of distribution opex, we compared Western Power's distribution opex with that of the aggregate of the distributors in several other Australian states. We have made the comparison on a state-wide basis, as this combines both the effects of both urban and rural networks in a way that matches Western Power's situation better than a comparison of individual entities. [95]

Western Australia has a customer density of 11 per km of line, similar to NSW/ACT (12), Queensland (10) and South Australia (9). Victoria has a higher customer density (16).

Western Power categorises sub-transmission as transmission whereas sub-transmission is a function of the distribution businesses in the other states in the comparison. We therefore adjusted Western Power's opex to remove sub-transmission costs from the analysis. [96]

Data for other States was obtained from publicly available information.[97]

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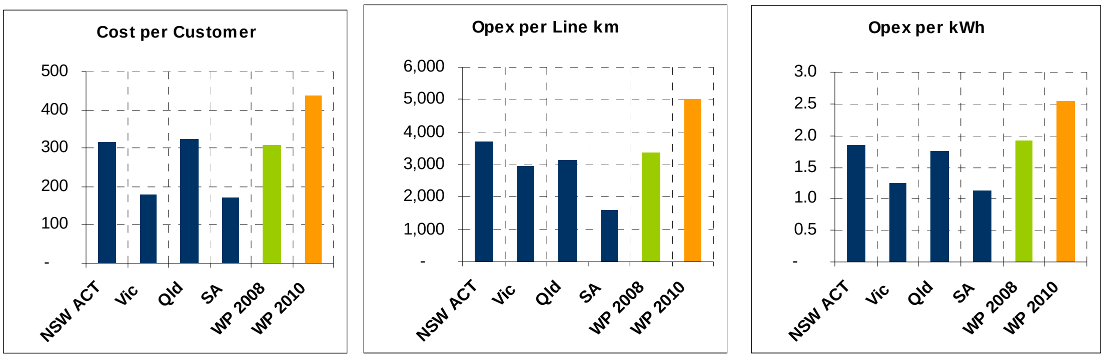
95 Our terms of reference asked us to consider benchmarking, where possible.

96 See section 8.4.

Figure 9.3 shows the comparison of Western Power's projected FY 2008 distribution opex with that reported for the other states in the comparison, based on cost per customer, cost per line km and cost per kWh distributed. A comparison with the levels forecast by Western Power for the first year of the next period is also shown.

Figure 9.3: Comparison of Distribution Opex (State-Wide Basis) a/



a/ Cost per customer and cost per unit of line length are in dollars; cost per kWh is in cents.

The analysis shows that for FY 2008, Western Power has opex levels similar to those reported in NSW/ACT and Queensland but higher than those reported in Victoria and South Australia on the measures compared.

The analysis also shows that Western Power's proposed level of opex in FY 2010 is likely to move above the levels in the other states, unless distributors in the other states increase their levels of expenditure also – as is possible, as the next round of regulatory assessments is presently under way in the ACT and NSW, commencing in Queensland and shortly to commence in Victoria.

Observations and Conclusion

The most that can be said from the analysis is that Western Power's opex is presently not below the average of that reported in the other states in the comparison – nor above it either, at least in two measures out of the three.

Given the differences in Western Power's circumstances vis-à-vis the businesses in the other states, the usual uncertainties inherent in benchmarking (especially in relation to any network business serving a predominantly rural area) and uncertainty about the likely levels of opex that will be agreed to in the present round of regulatory reviews, we conclude that we should not rely on this analysis when forming our opinion and, accordingly, do not do so.

9.5 Recommended Level of Expenditure

Having considered the factors reported in this section, we conclude for the purpose of this review that a reduction of $87 m should be made in Western Power's proposed distribution opex as shown in Table 9.10.

[97] Victoria: performance reports published by the Essential Services Commission. South Australia: performance reports published by ESCOSA. NSW and ACT: regulatory submissions to the AER. Queensland: regulatory determinations by and submissions to the QCA. Some statistical information was obtained from the AER's publication *State of the energy industry* and individual company websites.

Table 9.10: Recommended Level of Distribution Opex ($ 2009 m)

	Present Period (AA1)				Next Period (AA2)				
	Actual		Forecast	Total	Proposed			Total	Diff
YE 30 June	2007	2008	2009		2010	2011	2012		
Proposed by W Pwr	255	260	263	**777**	394	416	436	**1,247**	+ 60%
Adjustments									
Preventive mtce.					(21)			**(21)**	
Corrective mtce.					(9)	(13)	(17)	**(39)**	
Smart metering					(3)	(7)	(11)	**(22)**	
Outage payments					(2)	(2)	(2)	**(6)**	
					(35)	(22)	(30)	**(87)**	
Recommended Level					**359**	**395**	**406**	**1,160**	**+ 49%**

10 Conclusions and Recommendations

10.1 Opinion

Having considered the information received from Western Power and the factors required to be considered as summarised in this report, and based on that information, the representations made to us by Western Power and our own experience, our opinion in respect of Western Power's expenditure proposals for its revised access arrangement and for the purpose of this review is as stated below.

(a) Considering the matters discussed in sections 4.3, 5.1, 6.1 and 7.1 of this report, we accept the scope and prudence of the capital expenditure in the present period (FY 2007 to FY 2009) and its efficiency in terms of planning and prioritisation – in essence, the scope and timing of the capital expenditure made in the present period – but are not able to offer an opinion on its efficiency in terms of cost-effectiveness, as information on the variances in expenditure from the levels approved for the present period was not supplied – see sections 5.9, 6.8 and 7.3 of this report.

(b) Western Power's proposed capital expenditure in the next period (FY 2010 to FY 2012) is considered prudent and efficient, subject to adjustment to remove the proposed risk estimating allowance. The recommended adjustments are shown in sections 5.9 and 6.8.

(c) Western Power's proposed operating expenditure in the next period is considered prudent and efficient, subject to adjustments for various reasons. The recommended adjustments are shown in sections 8.5 and 9.5. The adjustment recommended in Western Power's distribution opex reflects, amongst other things, our concern about its ability to increase its resources at the rate proposed and to support those resources through training and field audit work at a sufficient level to achieve its ambitious increase in expenditure, especially in preventive maintenance.

For the avoidance of doubt, the statements in this section of the report that expenditure is deemed in our opinion to be "prudent and efficient" are made in the context of the Code and a service provider "incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services".

10.2 Matters for the Authority's Consideration

In concluding this report – particularly given the lack of full information available to us for the review of capital expenditure in the present period – we would like to draw the Authority's attention and consideration to the issues discussed in sections 4.2 to 4.5, *viz.*

- the budgeting and reporting issues reported in relation to the present period,

- the lack of information available to support additions to the capital base,
- the incorporation in the estimates of an allowance for an “estimating risk factor” and
- various other issues arising, including:
    - the incorporation of real price escalation in the estimates,
    - the deliverability of the proposed work programme,
    - the impact of past constraints on capital expenditure,
    - the potential impact of the present, changed, economic situation, and
    - potential matters related to the proposed revisions to the technical rules.

Some other matters are raised in the text where relevant to our work or related closely to it. Instances are in sections 5.2 regarding the possible impact of the present economic slow-down and sections 5.4, 6.1 and 6.3 in relation to customer capital contributions and gifted assets.

10.3 Conditions Accompanying Our Opinion

Assessment Not an Assessment of Condition, Safety or Risk

Notwithstanding any other statements in this report, this review is not intended to be and does not purport to be an assessment of the condition, safety or risk of or associated with Western Power’s assets and nothing in this report shall be taken to convey any such undertaking on our part to any party whatsoever.

All Earlier Advice Superseded

For the avoidance of doubt, we confirm that this report supersedes all previous advice from us on this matter, whether written or oral, and constitutes our sole statement on the matter.

Disclosure

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.

Disclaimer

This report has been prepared solely for our client, the Economic Regulation Authority (the Authority), for the stated purpose. Wilson Cook & Co Limited, its officers, agents, subcontractors and their staff owe no duty of care and accept no liability to any other party, make no representation or warranty as to the accuracy or completeness of the information or opinions set out in the report to any person other than to its client including any errors or omissions howsoever caused, and do not accept any liability to any party if this report is used for other than its stated purpose.

Non-Publication

With the exception of its publication by the Authority, in relation to its review of Western Power’s expenditure proposals, neither the whole nor any part of this report may be included in any published document, circular or statement or published in any way without our prior written approval of the form and context in which it may appear.

Appendix A: Terms of Reference

The consultant will be required to provide technical advice and assistance to the Secretariat, in order for it to review Western Power's proposed revisions to its access arrangement for the SWIN. Based on the provisions under the Access Code for the review of an access arrangement, the consultant will be required to undertake various tasks, namely in relation to the calculation and evaluation of actual and forecast costs, in particular:

Western Power's Operating and Capital Expenditure

Review and provide advice on the reasonableness and appropriateness of, or recommend alternatives to, the components and values in Western Power's proposed revisions to its opex and capex.

Review relevant consultant reports commissioned by Western Power, and provide advice either generally or in relation to a particular matter, as appropriate.

Investigate, compare and proposed variations for opex and capex forecasts, taking into account historical and industry benchmark data.

In relation to forecast expenditure (non-capital costs and new facilities investment), review and provide advice as to whether the forecasts are consistent with the specific requirements of the Access Code (sections 6.40 to 6.42 and 6.49 to 6.51).

Investigate and provide advice on any discrepancies, and provide recommendations, where appropriate.

Western Power's Capital Base

Review and provide advice as to whether Western Power's proposed revisions to determine its capital base for the second access arrangement period is consistent with the requirements of the Access Code (section 6.48).

Review and comment on the reasonableness and appropriateness of, any assumptions made by Western Power in its calculations.

Review and comment on Western Power's asset registers, including the levels of accuracy of actual and forecast costs, given historical and industry benchmark data.

Identify any matters that, in the opinion of the consultant, may warrant further investigation by the Authority and/or explanation from Western Power.

It will be the responsibility of the consultant to ensure that all required work is undertaken within the timeframes required by the Secretariat in order to meet the various timing requirements specified in the Access Code. The consultant will be provided with specific timings and assistance from the Secretariat as appropriate.

The Secretariat anticipates that it will begin its formal access arrangement review preparations in mid-September, which will include finalising contractual arrangements with consultants. It is envisaged that the actual review of Western Power's proposed revisions will take place between October 2008 and May 2009, based on the Authority issuing a draft decision, final decision and further final decision, with no extension of time provisions under the Access Code utilised. The target commencement date for Western Power's proposed revisions, assuming that the proposed revisions are approved by the Authority, is 1 July 2009.

Other Requirements

In addition, the consultant may be required to:

- Collate the results of investigations, advice and recommendations into an independent technical report/paper, to be used by the Authority as supporting material in its draft and final decisions (and further final decision, if required).
- Review and provide advice on technical aspects of relevant documents, such as public submissions received during the Authority's first and second rounds of public consultation.
- Brief the Authority on particular matters, as requested.
- Liaise directly with other consultants appointed by the Authority to undertake tasks in relation to the access arrangement review. Such consultants may include economic/financial advisors, legal professionals and media advisors.
- Participate in meetings with the Authority, Western Power and/or other interested parties in relation to the proposed revisions.

The consultant may have regard to industry best practice, applicable legislation, precedent relevant to regulated energy infrastructure in Australia and elsewhere, and the objectives of the Access Code.

Appendix B: List of Personnel Met

Meetings or discussions were held with the following personnel: [98]

Economic Regulation Authority

Mr Peter Kolf, General Manager
Mr Robert Pullella, Executive Director, Competition, Markets and Electricity
Ms Karen Tilsed, Acting Assistant Director, Electricity
Ms Sarah Walsh, Acting Manager, Projects
Mr Wayne Blakiston, Analyst
Dr Ray Challen, Consultant
Mr Geoff Brown, Consultant

Western Power Corporation

Mr Ken Brown, General Manager, System Management
Mr Mark De Laeter, General Manager, Customer Services
Mr Peter Mattner, Manager, Regulation, Pricing and Access Development
Mr Murray Caston, Manager, System Operation Control
Mr Laurie Curro, Manager, Network Planning and Development
Ms Lisa Cunningham, Acting Manager, Strategic Programs
Mr Shane Duryea, Manager, Network Operations
Mr Gair Landsborough, Manager, Business Analysis
Mr Mike Lu, Manager, Customer Service
Mr Syd McDowell, Manager, Network Performance
Mr David Nairn, Manager, Investment Management
Mr Rodney Newton, Manager, SCADA and Information Systems
Mr Graham Rowe, Manager, Works and Resource Planning
Mr John Brisbane, Asset Performance Manager, Transmission Asset Performance
Mr Hai Bui, Transmission Capacity Planning Manager
Mr Neil Chivers, Access Solutions Manager
Ms Ailin Dolfi, Budgeting & Reporting Manager
Mr Johan Esterhuizen, Asset Strategy Manager, Distribution Asset Performance
Mr Dean Frost, Country Regional Planning & Development Manager
Mr Stephen Iacopetta, Asset Manager, Energy Solutions
Mr Kamal Kamalanathan, Contract Engineer, Distribution Asset Performance
Mr Phil Kelloway, Branch Manager, Planning & Market Operations
Ms Anna Locke, Administration Assistant, Network Investment
Mr Mark McKinnon, Reliability & Power Quality Manager
Mr Peter Martino, Metro Regional Planning & Development Manager

[98] The positions indicated are those held at the time.

Mr Sebastian Ravi, Networks Engineer, Distribution Asset Performance
Mr Daniel Rossandich, Delivery Strategy Manager, Planning Enablement
Mr Hugh Smith, Pricing Analyst
Mr Adam Stephenson, Commercial Administrator, Client Services Administration
Mr Robert Toms, Branch Manager, Operational Excellence
Mr Mehdi Toufan, Group Manager, Transmission Delivery
Mr Greg Turnbull, Open Access Engineer