Geoff Brown & Associates Ltd

TECHNICAL REVIEW OF WESTERN POWER'S PROPOSED ACCESS ARRANGEMENT FOR 2012-2017

Prepared for

ECONOMIC REGULATION AUTHORITY

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EXECUTIVE SUMMARY

Introduction

Geoff Brown and Associates Ltd (GBA) has been contracted by the Economic Regulation Authority (Authority) to undertake a technical review of the access arrangement information submitted by Western Power in support of its proposed revisions to its existing access arrangement. The revised access arrangement, once approved by the Authority, will apply during Western Power's third regulatory period (AA3), which starts on 1 July 2012 and ends on 30 June 2017. The review included, but was not limited to, an assessment of the quality of Western Power's processes for the management of expenditure, the reasonableness of Western Power's actual capital expenditure (capex) during its second regulatory period (AA2), and the reasonableness of its planned service standards and forecast capex and operations and maintenance expenditure (opex) requirements for AA3. This report documents the findings of our review.

Governance and Expenditure Management

Western Power has prepared detailed plans for transmission network development and transmission and distribution network maintenance and its forecast AA3 expenditure is based on these plans. However we have not seen a similar plan covering capacity expansion of the distribution network and the basis on which the AA3 distribution network capacity expansion expenditure forecast was prepared is therefore less clear. Many of Western Power's plans appear to have been prepared specifically as a basis for the development of the AA3 opex and capex forecasts and there is little evidence that they are embedded in Western Power's ongoing governance and expenditure management processes.

Processes for managing the development and implementation of capex and opex projects and programs have improved significantly since the AA2 review. However further improvements are possible particularly in relation to the development and assessment of alternative options for expenditure projects and programs. In addition, Western Power still lacks a quantitative risk assessment tool and the application of risk management techniques to the prioritisation of expenditure appears unstructured and subjective. Western Power is planning to improve its risk management processes and is purchasing new asset management software. However the extent to which it is planning to further integrate risk assessment into its expenditure planning processes and to implement a maintenance management system based on condition based risk management (CBRM) principles consistent with industry best practice remains unclear.

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

Service Levels

The service levels provided by Western Power during the first two years of AA2 were better than the benchmark levels in the AA2 access arrangement in 34 of a total of 38 measures. This excellent performance was achieved notwithstanding the significant levels of under-expenditure on both the capex and opex allowed by the AER when determining the regulated revenue cap for AA2.

We see no reason why these improved service levels should not be maintained during AA3. Given the improvement in service levels that Western Power has been able to deliver since the beginning of AA1, we suggest that service level benchmarks and service standard adjustment mechanism (SSAM) targets be determined on the basis of Western Power's actual performance over the three year period

2008-11 rather than the five year period 2006-11. Such benchmarks and targets would better reflect Western Power's expected performance during AA3. We see little point in setting access arrangement benchmarks at very low levels since such benchmarks would normally be exceeded by a significant margin, and would not accurately reflect the price-quality value proposition offered by Western Power to network users. In our view, benchmarks and SSAM targets should both be set at a level that refects Western Power's expected average service levels and Western Power should only be considered to have breached its regulatory service level obligations if it consistently fails to achieve its access arrangement benchmarks.

Western Power is proposing to reduce the number of benchmarked service level measures in the AA3 access arrangement to better align them with the reference services it offers. We agree with its proposals for the distribution network but consider that its proposed benchmarked transmission network service level measures are inadequate. We also see little value in Western Power's proposed individual transmission customer service measure but consider that transmission circuit availability, number of interruptions (>1 system minute and >0.1 system minute), and average interruption duration should all be benchmarked.

We suggest that the transmission network SSAM be expanded to put up to 1% of transmission revenue at risk and to include the two number of interruptions measures and also an average interruption duration measure. This would be consistent with the Australian Energy Regulator's (AER's) standard transmission service target performance incentive scheme (TSTPIS). Western Power has calculated its SSAM incentive rates in a manner generally consistent with the approach taken by the AER in the TSTPIS. However the incentive rates for the distribution network reliability service levels are based on Western Power's analysis of its distribution network load profile and are generally higher than those specified in the AER's standard distribution service target performance incentive scheme (DSTPIS), (which appear to be based on what the AER considers a typical load profile). Since Western Power's proposed targets for distribution network reliability service levels are lower than the service levels Western Power is currently delivering, we think it likely that Western Power will earn a SSAM reward for these service measures, when averaged over AA3. It follows that this reward would be higher than if the AER incentive rates were used.

AA2 Capital Expenditure

Western Power's total capex during AA2 is expected to be 34% ($1.3 billion) lower than the $3.9 billion approved by the Authority. The major areas of under-expenditure have been capacity expansion and customer driven capex, particularly on the transmission network and to a lesser extent on distribution. Notwithstanding this Western Power has met or exceeded 89% of AA2 access arrangement network service level benchmarks over the first two years of AA2 and, over this time, network service levels have shown an improvement from earlier years.

While there are a number of reasons for this underspend, including the global financial crisis (GFC) and reduced demand for new customer connections, the fact that Western Power still exceeded its service level targets in spite of substantial capex reductions indicates there was some inefficiency in its approved AA2 capex forecast. The Authority could decide that, given that any capacity expansion or customer driven capex overspend that meets new facilities investment test (NFIT) requirements can be recovered in AA4 through the investment adjustment mechanism (IAM), it is better for the approved capex to be a little lower, rather than substantially higher, than the amount eventually required. Customers will then not be asked to pay more during AA3 than needed to fund the actual capex requirement, and the incentive on Western Power to deliver only an efficient level of capex is likely to be greater. This is because the actual AA3 capex is likely to be subject to more intense ex-post scrutiny at the time of the AA4 review if it is higher than the Authority's approved amount.

We reviewed a total of 19 capex projects undertaken by Western Power in AA2 for compliance with the requirements of the NFIT in the Access Code and comment that:

- We consider that only the initial cost estimate of $3.2 million for the phase 1 mobile work station (MWS) project satisfies NFIT requirements as we are not satisfied that the $5.7 million cost overrun on this phase satisfies the NFIT efficiency test;

- We are unable to form a view on the extent to which the $46.7 million SPOW capex that we did not review meets NFIT requirements. In its AA3 access arrangement information, Western Power considered that all actual capex on this program was NFIT compliant.

However the business case that it subsequently provided on the meter data management (MDM) subproject did not support Western Power's estimated AA2 subproject capex;

- We do not consider that any capex associated with the Picton-Busselton line meets NFIT requirements;
- Western Power has confirmed that all transmission line relocation capex should be recovered from the party requesting the relocation and that its proposed NFIT amount at the end of AA2 represents its estimate of outstanding contributions still to be recovered from customers at that time. . In the event that a line relocation does not proceed, or capital contributions are unable to be recovered from the party requesting the relocation, capex incurred by Western Power will remain in the capital base and be funded by customers;
- We do not consider that the $4.5 million capex Western Power expects to spend in 2011-12 and classified as planning or environmental meets NFIT requirements;
- Western Power's expected metering installation and replacement expenditure in 2011-12 may be high in that it does not appear to have taken into account the fact that meter purchases in 2010-11 appear to have been significantly higher than the actual requirement. To this extent we think the NFIT compliant amount for this line item might have been over stated; and
- We were unable to determine the exact amount of Western Power's contribution to the state underground power program (SUPP) that meets NFIT requirements but expect it to be approximately $21 million.

The proposed NFIT compliant amount in the AA3 access arrangement information was based on Western Power's estimate of its actual 2011-12 capex at the time it prepared the document. This estimate has now been superseded by the F1 forecast, which takes into account actual expenditure at the end of the first quarter, and will be updated quarterly as the year progresses.

Two projects we reviewed, distribution wood pole replacement and meter replacement involve the routine removal from service of assets that may not be fully depreciated in Western Power's capital base. In neither case has Western Power provided for accelerated depreciation in its assessment of the NFIT compliant amount.

Cost Estimation

We reviewed the processes used by Western Power to prepare the cost estimates for the capex forecasts and found them to be soundly based and consistent with good electricity industry practice. Hence, we have generally accepted that Western Power's estimates of the cost of individual capex projects are reasonable and largely focused our assessments of the AA3 transmission and distribution capex forecasts on the need for, and timeliness of, the different projects and programs proposed by Western Power.

We also found Western Power's approach to indirect cost allocation to be broadly consistent with approaches used by other utilities within Australia and consider it unlikely that there is any double counting of costs between capex and opex.

The AA3 expenditure forecasts submitted by Western Power in its access arrangement information include the impact of real cost escalation. Western Power engaged independent consultants CEG to estimate the cost escalators that should be included in the forecasts. We have reviewed the consultant's report and found that the approach used in estimating the various cost escalators to be reasonable. However the labour cost escalators adopted by Western Power are based on average weekly ordinary time earnings (AWOTE) projections rather than wage price index (WPI) rates. The Authority in the past has used WPI (more commonly referred to as labour price index or LPI) as its preferred real labour cost escalator. Furthermore, in its more recent regulatory decisions, the AER has also used LPI based escalators.

Inventory

There is a cost associated with financing inventory and inventory is a necessary component of operating a network business. It therefore seems reasonable to include efficient inventory levels in the capital base. Western Power has provided benchmarking statistics that place its inventory levels at reasonable levels compared to network businesses in other jurisdictions and has proposed an asset turnover ratio higher than its current inventory turnover.

Peak Demand Forecasts

Western Power has used the peak demand forecast in its 2010 Annual Planning Report (APR) for a central economic growth scenario, with a 10% probability of exceedence, as the basis for forecasting its AA3 expenditure requirements. We consider this reasonable. We have also reviewed Western Power's demand forecasting methodology and consider it consistent with good industry practice.

However, since submitting its AA3 access arrangement information, Western Power has issued its 2011 APR with a lower peak demand forecast. This new load forecast has removed approximately 3 years growth – it suggests that the 2015 peak demand assumed when preparing the AA3 expenditure forecast will not now occur until 2018. Should this latter forecast materialise, many of the capacity expansion projects scheduled for the last three years of AA3 could be deferred to AA4. However, we do not suggest deferring strategic projects intended to change the underlying configuration of the existing transmission network.

AA3 Transmission Capex Forecast

Western Power's total AA3 transmission capex forecast is $1,617 million, net of customer contributions and excluding real cost escalation. We suggest the following adjustments could be made to this forecast:

- The proposed new CBD zone substation and its associated 132 kV supply cables could be deferred to AA4, for a saving of $125.0 million. We are not satisfied that this proposal is consistent with the least cost development plan for the CBD and, given the information provided by Western Power, we see little risk in deferring this project. This would allow a strategic development plan for the CBD to be prepared;

- The proposed Eneabba terminal station could be deferred for a reduction of $16.9 million. This asset is speculative in that it is required only to connect potential new wind generation. It is not clear if, or when, such generation will want to connect;

- Western Power's provision for net customer driven capex is high when compared with historic expenditure and taking into account the expected rate of network growth. Our suggested reduction is $56.1 million;

- The Authority could decide to defer capacity expansion projects as a result of the reduced demand forecast in the 2011 APR. Based on a very high level analysis, we consider that a reduction of $246.1 million would be reasonable. This has been assessed on the following basis:

    - A 40% reduction in transmission supply capex, after the removal of the CBD substation, for a saving of $106.9 million;

    - A 40% reduction in transmission voltage capex for a saving of $26.4 million;

    - Deferral of the Mungarra-Geraldton 132 kV line for a saving of $40.4 million; and

    - Deferral of the Kojonup-Albany line for a saving of $72.9 million.

Taken together, these adjustments would reduce the AA3 transmission capex to $1,173.6 million, a reduction of 27%.

AA3 Distribution Capex Forecast

Western Power's total AA3 transmission capex forecast was $2,657.6 million, net of customer contributions and excluding real cost escalation. We suggest the following adjustments could be made to this forecast:

- A reduction of $28.5 million in transmission driven distribution capex, as Western Power's forecast seems high compared to the level of transmission driven expenditure incurred in AA2. This adjustment is separate from the load driven transmission driven capex adjustment identified below;
- A reduction of $6.7 million in the capex for new and replacement standard meters; and
- A reduction of $5.1 million in the capex for the three phase meter replacement program.

Should the Authority decide that the AA3 capex amount should take account of the reduced peak demand forecast in the 2011 APR then we suggest the following additional reductions:

- A further reduction of $10.7 million in transmission driven distribution projects; and
- A reduction on $45.9 million in the capex for other high voltage capacity expansion distribution projects.

Taken together, these adjustments would reduce the AA3 distribution capex to $2,560.7 million, a reduction of 3.6%.

Information Technology Capex Forecast

Western Power's forecast information technology (IT) capex for AA3 was $165.6 million. We suggest that this be reduced by $16.8 million (10.1%) as we do not consider that Western Power has provided valid justification for its proposed 76% average annual increase in its business as usual IT capex requirement.

Indirect Cost Allocation

We suggest that the total indirect costs allocated to capex during AA3 be reduced by $98.3 million (13.7%). The information provided by Western Power its indirect costs during AA2 was limited, but there appears to be a step increase in actual indirect cost allocations in 2010-11 and the forecast allocation in 2012-13. This has not been justified and we think it is excessive.

Opex

We propose the following two adjustments to Western Power's opex forecast:

- A modelling adjustment that takes account of errors we found in Western Power's scale escalation model, proposed adjustments to the network growth factors used by Western Power, adjustments to the 2010-11 base year opex used by Western Power in its scale escalation model and adjustments to non-escalated line item forecasts incorporated into Western Power's overall estimate of its AA3 opex requirement. Our proposed modelling adjustment is a reduction of $176.9 million (7.2%); and
- A 2% compounding efficiency adjustment after 2012-13. This is primarily intended to capture the efficiency gains from Western Power's strategic program of works (SPOW), which have been used by Western Power in its business cases to justify subprojects within the program. We also consider there is significant scope for additional efficiencies to be captured thorough the ongoing refinement of Western Power's governance and business processes. Our proposed efficiency adjustment totals $90.3 million or 3.7% of the Western Power forecast.

Taken together, these two adjustments have the effect of reducing Western Power's forecast AA3 opex form $2,445.0 million to $2,177.8 million, a reduction of 10.9%.

1. INTRODUCTION

GBA has been engaged by the Authority to provide technical advice in relation to capex and opex evaluations and other relevant technical matters relating to the Authority's review of Western Power's proposed access arrangement for AA3. This advice is provided in this report.

Western Power's access arrangement details the terms and conditions, including prices, that apply to users of its electricity transmission and distribution network, otherwise known as the south west interconnected network (SWIN). Electricity networks in Western Australia are regulated under the Electricity Networks Access Code 2004 (Access Code), which outlines a framework for the preparation, review and approval of access arrangements. Under this framework Western Power's access arrangement must be approved by the Authority before it comes into force.

Western Power's current access arrangement covers the three year period from 1 July 2009 to 30 June 2012 (AA2). On 1 October 2011, Western Power submitted proposed revisions to the access arrangement that, once approved by the Authority, would apply over the period 1 July 2012 to 30 June 2017 (AA3). The Authority may require Western Power's proposed revisions to be modified before it grants approval.

Under clause 4.28 of the Access Code the Authority must not approve an access arrangement unless it is satisfied that meets the objectives of the Access Code and covers all matters specified in chapter 5 of the Access Code. The advice provided in this report is intended to assist the Authority determine whether or not Western Power's proposed revisions to its current access arrangement meet these criteria and covers, but is not limited to, the following areas:

- the effectiveness of Western Power's governance and expenditure management procedures and the extent to which these are consistent with best industry practice;
- the need for, and efficiency of, Western Power's actual capex over the current AA2 period. This assessment is required to assist the Authority determine the reasonableness of the proposed value of the capital base at the beginning of AA3;
- the levels of service that Western Power is proposing to provide during AA3;
- the methodology used by Western Power to forecast its opex and capex requirements during AA3;
- the methodology used by Western Power for forecast electricity demand and the reasonableness of its forecast growth in electricity demand during AA3;
- the efficiency and reasonableness of Western Power's forecast capex requirements during AA3; and
- the efficiency and reasonableness of Western Power's forecast opex requirements during AA3.

In preparing the advice provided in this report, we have relied on the AA3 access arrangement information that Western Power submitted to the Authority in support of its proposed revisions. We also relied on additional information provided to us by Western Power during the course of this review. However, our review was not an audit and we were not required to independently verify, or satisfy ourselves of, the accuracy of the information provided. Therefore, while we clarified information that appeared incorrect or inconsistent, we generally took the information provided by Western Power at face value. It follows that we cannot be held responsible for misleading the Authority if the advice provided in this report is found to be based on the review or analysis of inaccurate or incomplete information provided to us by Western Power.

2. OVERVIEW OF AA3 EXPENDITURE FORECASTS

2.1 INTRODUCTION

In this section we overview Western Power's forecast expenditure requirements for AA3 and compare them with Western Power's actual and expected[1] expenditures for AA2, as well as with the AA2 expenditures allowed by the Authority in its final decision on the AA2 access arrangement.

In evaluating the expenditures identified in this report the following should be noted.

- Unless noted otherwise, AA2 and AA3 expenditures are expressed in real 2011-12 dollars. This is generally consistent with the approach used by Western Power in its AA3 access arrangement information;
- Unless noted otherwise, forecast AA3 expenditures exclude the impact of real price escalation and are therefore lower than the corresponding forecasts provided by Western Power in its AA3 access arrangement information. We made this adjustment to increase the validity of year on year expenditure comparisons. We have relied on information provided to us by Western Power to determine the amount of this adjustment.
- All expenditures for the current 2011-12 year are Western Power's expected expenditure after adjusting its approved work program (AWP) budget to take into account its actual expenditure in the first quarter[2]. Hence, these expenditures will differ from the corresponding expenditure in Western Power's AA3 access arrangement information, which we understand were based on the AWP budgets. Western Power provided us with the update of its expected 2011-12 expenditures after it submitted its AA3 access arrangement information.
- Expenditures in the tables in this report have generally been copied directly from spreadsheet models and may not add due to rounding.
- As AA2 was a three year period and AA3 extends for five years, direct comparisons of total expenditures in each period are not valid. Where comparisons of the level of expenditure in AA2 and AA3 were needed, we compared the average annual expenditures in each period.
- For economy of wording, the actual expenditure in 2009-10 and 2010-11 and the expected expenditure in 2011-12 are often collectively referred to as "actual" AA2 expenditure.

2.2 CAPITAL EXPENDITURE

Western Power's actual and forecast capex for AA2 and AA3 are shown in Table 2.1. Expenditures shown in the table are gross in that they include gifted assets and expenditure on assets that are owned by Western Power but funded through a capital contribution. For all asset categories, Western Power's forecast AA3 average annual capex is less in real terms than the average annual capex allowed by the Authority for AA2 and in the case of transmission assets this reduction is more than 30%.

[1] Expected expenditure refers to the current 2011-12 year, where actual expenditures are not known.
[2] This is known internally within Western Power as the *F1 forecast.*

Table 2.1 Approved, Actual and Forecast Capex ($ million, real 2011-12)

	AA2			AA3					Average Annual
	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	
Transmission									
Approved	323.9	595.2	650.5						523.2
Actual	243.0	143.6	191.8						192.8
Forecast				346.2	260.8	343.5	488.2	378.3	363.4
Distribution									
Approved	632.8	736.0	780.7						716.5
Actual	579.7	541.1	656.7						592.5
Forecast				653.3	705.1	707.5	670.6	665.2	680.3
Corporate Support									
Approved	47.8	71.9	56.3						58.6
Actual	47.9	75.1	85.7						69.6
Forecast				75.7	72.2	47.4	49.0	45.5	58.0

Source: Western Power and GBA analysis. Impact of real price escalation not included.

Figures 2.1 to 2.3 present the information provided in Table 2.1 in graphical form.

Figure 2.1: Approved, Actual and Forecast Transmission Capex ($ million, real 2011-12)

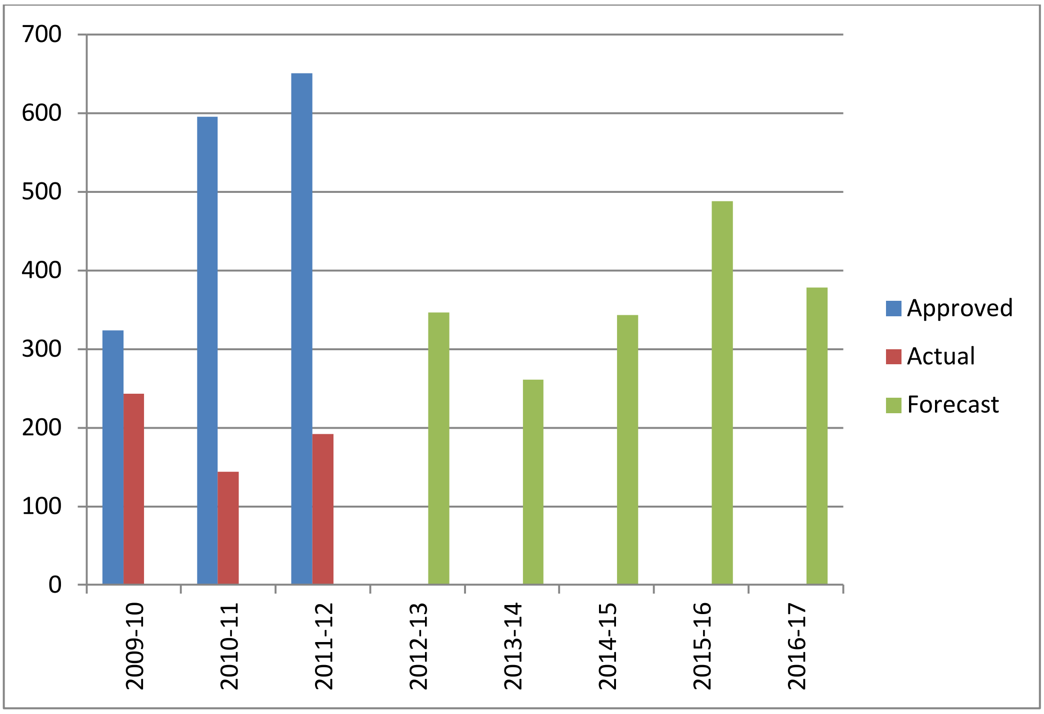


Figure 2.2: Approved, Actual and Forecast Distribution Capex ($ million, real 2011-12)

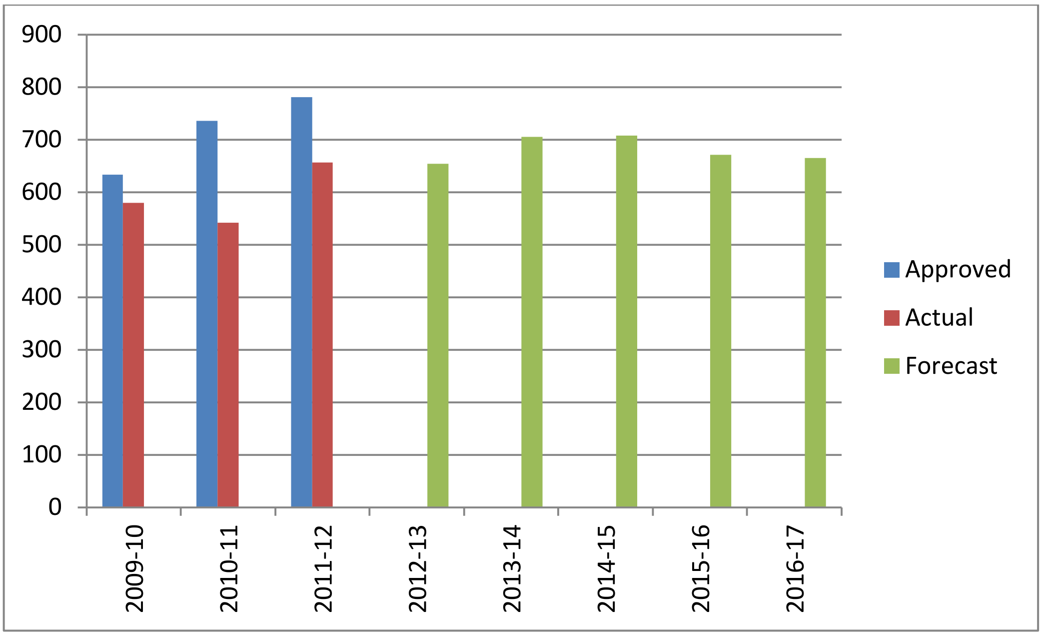
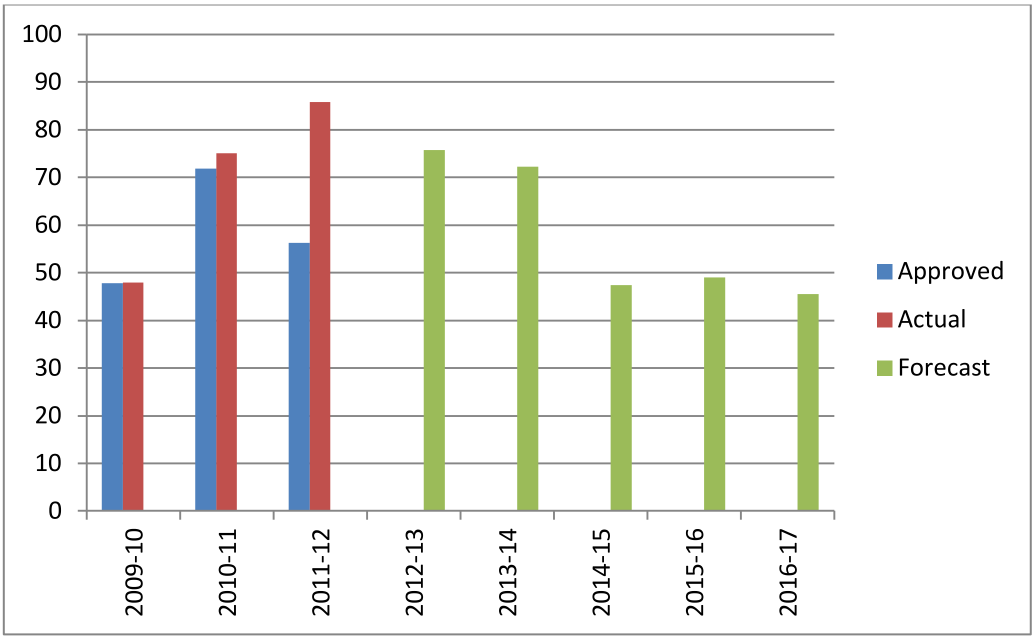


Figure 2.3: Approved, Actual and Forecast Corporate Capex ($ million, real 2011-12)



2.3 OPEX

Western Power's actual and forecast opex for AA2 and AA3 are shown in Table 2.2. In preparing this table we have not included opex for non-reference services as this is not funded through the revenue cap.

Table 2.2 Approved, Actual and Forecast Opex ($ million, real 2011-12)

	AA2			AA3					Average Annual
	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	
Transmission									
Approved	52.8	73.9	80.3						69.0
Actual	47.3	61.7	75.6						61.5
Forecast				79.3	74.2	79.1	83.5	91.7	81.6
Distribution									
Approved	219.6	297.7	356.1						291.1
Actual	237.5	251.3	290.9						259.9
Forecast				283.4	290.8	298.5	297.4	311.1	296.2
Corporate Support									
Approved	113.8	116.8	119.8						116.8
Actual	87.3	102.5	108.2						99.3
Forecast				107.9	107.6	109.8	114.3	116.2	111.2

Source: Western Power and GBA analysis. Impact of real price escalation not included.

Figures 2.4 to 2.6 present the information provided in Table 2.2 in graphical form.

Figure 2.4: Approved, Actual and Forecast Transmission Opex ($ million, real 2011-12)

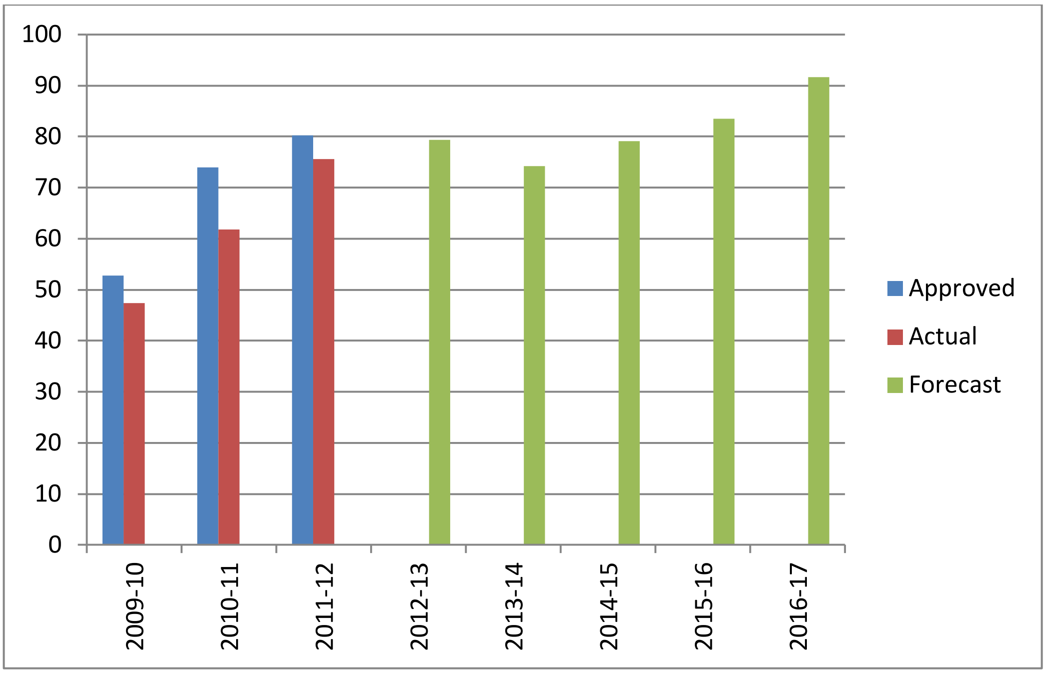


Figure 2.5: Approved, Actual and Forecast Distribution Opex ($ million, real 2011-12)

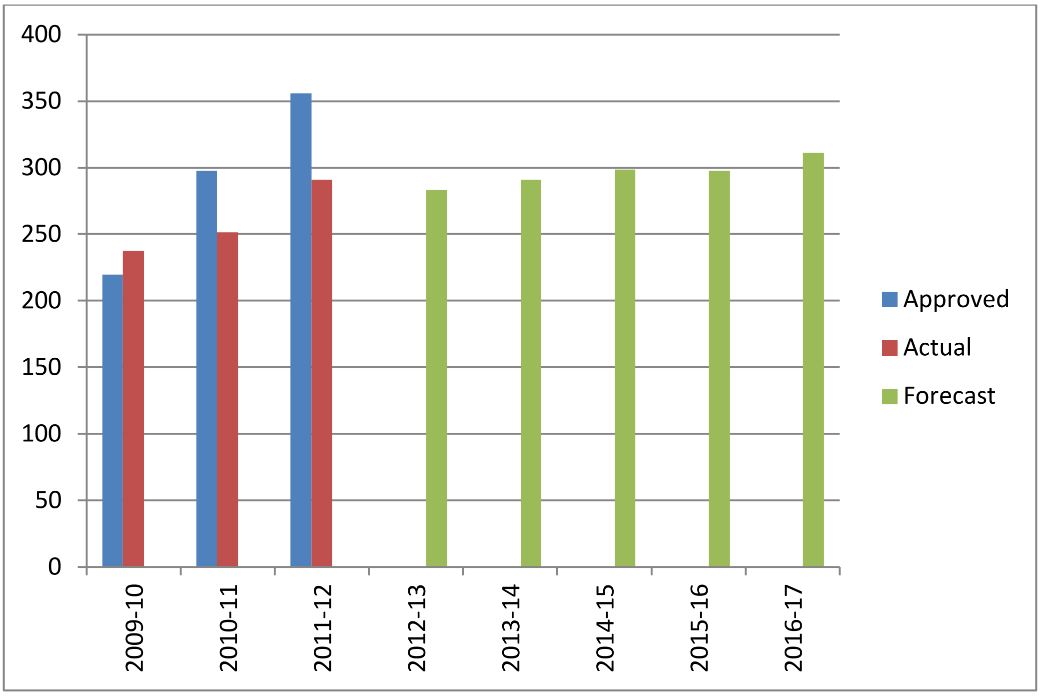
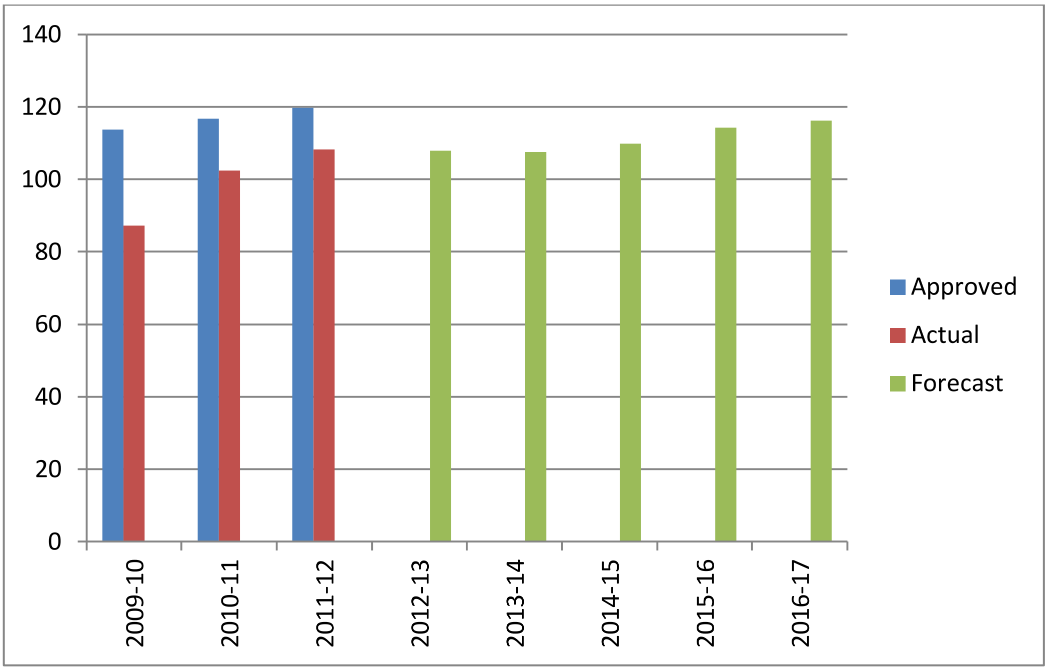


Figure 2.6: Approved, Actual and Forecast Distribution Opex ($ million, real 2011-12)



3. PROCESSES FOR MANAGEMENT OF EXPENDITURE

3.1 INTRODUCTION

This section of our report reviews the governance processes for the management of Western Power's expenditure, including the policies, processes and procedures that it has in place to plan and manage its capex and opex projects and programs. This includes the policies and processes that Western Power uses to:

- set expenditure budgets and develop annual work programs;
- formulate new projects and programs and approve them for implementation;
- control the actual cost of approved projects and programs; and
- forecast its capex and opex requirements for the AA3 regulatory period.

Particular consideration is given to:

- the alignment of the policies, procedures and processes for the management of expenditure with Western Power's higher level corporate objectives;
- the extent to which Western Power's policies and procedures are consistent with good industry practice;
- the extent to which Western Power's policies and procedures are implemented in practice;
- whether the improvements in governance policies and procedures that were under development at the time of the AA2 review have been implemented and embedded in the organisation[3];
- the effectiveness of internal audit processes; and
- the independent audit of Western Power's asset management processes undertaken at the request of the Authority.

In considering how well governance principles are applied in practice, we have examined a sample of projects and programs, taken from those implemented during the AA2 regulatory period and those proposed for AA3.

3.2 GOVERNANCE FRAMEWORK

Governance establishes the processes, systems and controls that ensure that all investment decisions are made consistent with corporate objectives and also with good electricity industry practice. It embraces clarity of roles and accountabilities, accurate/timely information and clear processes/criteria to support decision making, and the ongoing review and monitoring of business process and outcomes.

This section looks at the framework that Western Power has established in relation to governance and considers specific documented plans, policies, procedures and processes that are considered by Western Power to be key inputs into the framework underpinning its AA3 revenue proposal.

Western Power has identified the following documents as key to the governance of capex and opex investments within its network business:

- Network Investment Strategy;

[3] This will factor in the findings of the following report: *Review of Expenditure Governance, Western Power;* Geoff Brown & Associates Ltd, 14 July 2009.

- Transmission Network Development Plan;
- Network Management Plan;
- Approved Works Program;
- Works Delivery Strategy; and
- Works Program Governance Manual.

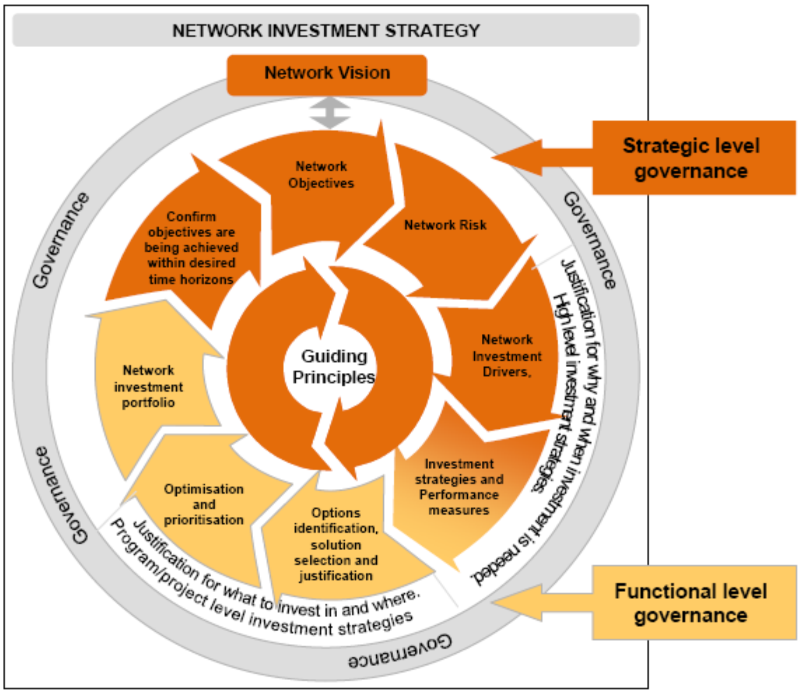
We reviewed each of these documents and our comments are summarised below.

3.2.1 Network Investment Strategy

Western Power's Network Investment Strategy (NIS) sets out the business's vision for the network and establishes the objectives associated with that vision. It identifies the key drivers for investment and sets out the strategies that are associated with each driver. Western Power indicates that it is a key document that underpins its network capex and opex requirements. It is supported by a range of other internal plans, processes, systems and policies.

The NIS identifies two levels of governance – a strategic level and a functional level, as shown in Figure 3.1. Strategic governance is undertaken by the Board and senior executive team and determines strategic objectives, risk considerations and network investment drivers for the business. Functional governance is generally undertaken at a lower management level and determines approaches to functions such as network option selection, optimisation and prioritisation leading to overall investment portfolio proposals.

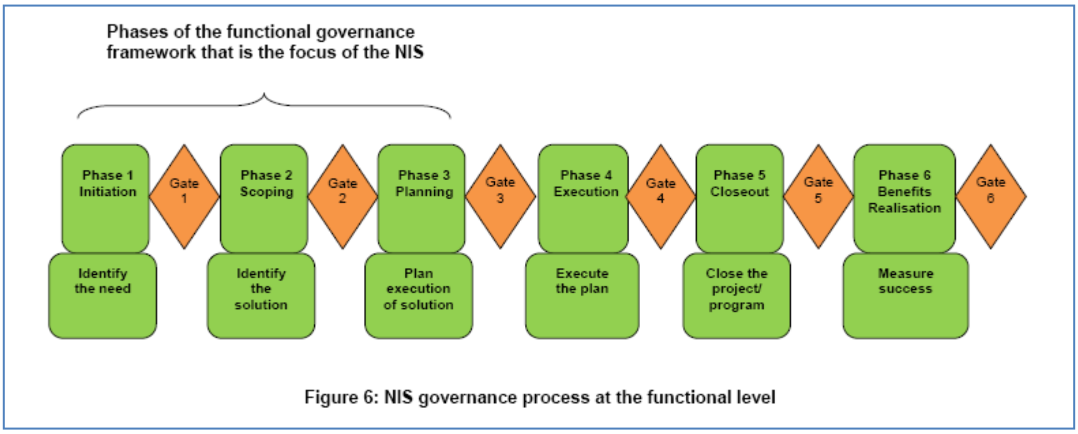
Figure 3.1: Levels of Governance



Source: Western Power

The NIS also introduces the functional level six phase / six gate process shown in Figure 3.2 that is used to manage expenditure. It starts with the identification of potential network investments and identifies expenditure and management controls through to the post implementation review of an implemented investment. The NIS focuses on the first three phases of this process - the initiation, scoping and planning phases leading to approved business cases, which are then incorporated into approved projects and programs.

Figure 3.2: Process for Controlling Expenditure



Source: Western Power

We consider that the NIS is a detailed and robust document and that the framework is well developed. We note however that the document does not consider project and program risk elements other than the physical network risk impacts. We questioned Western Power further on this and were advised that it formally assesses, evaluates and applies risk ratings to all projects using a qualitative approach. However it does not explicitly use evaluated ratings to compare relative risk levels across operational and capital projects and programs to prioritise when there are competing needs. Western Power indicated that it was developing a formal evaluation and prioritisation methodology as part of its strategic investment framework, which is scheduled for implementation in 2012 in conjunction with a network risk management tool.

Even though the six phase / six gate process that is used to manage expenditure is a significant improvement on the AA2 processes, the model has now been extended further to the seven phase / seven gate model described in the Works Program Governance Manual. Western Power has advised that the introduction of the additional phase/gate has been recent and the NIS document has not been updated to reflect the extension.

In a number of business cases we looked at during this review, Western Power did not appear to have considered a comprehensive range of project options. In some cases we thought the options presented were not real alternatives and often we thought the analysis was superficial. Some business cases did not address potential strategies for project deferral, such as demand management. Such options should at least be considered with any growth based project business case, regardless of the perceived viability of such deferral options.

We also detected a lack of comprehensive option identification and evaluation in some of Western Power's higher level development planning. For example, the information provided in support of Western Power's proposed new CBD substation provided little evidence that the proposed option was consistent with a long term, least cost strategy for addressing emerging network constraints within the Perth CBD. This project is discussed further in Section 7.2.2 and Appendix B2.

As a second example, we understand from presentations provided by Western Power to inform this review that some of the network development strategies that underpin Western Power's AA3 capex forecast, such as the strategy of limiting the extent to which the 132 kV transmission network is operated in parallel with the 330 kV system, only emerged after a cross-functional brainstorming exercise undertaken specifically in preparation for the AA3 review. We consider that the use of techniques such as brainstorming and cross-functional reviews should be more firmly embedded in Western Power's business processes, not only for the development of high level strategy but also in the planning of projects and programs to address specific needs. This will help ensure that a wide range of solutions to a specific problem are identified and, just as importantly, that all potential options are evaluated without any bias for any one solution.

We sought further information from Western Power on its processes for option identification and evaluation. It provided two recently published documents: *Guidelines for preparing Business Cases* and *Business Case Template – for AWP projects over $400,000,* which provide guidelines for the development of project alternative options. The implementation of the processes described in these documents should lead to more robust development and consideration of alternative project options (including project delay/deferral options). However, these are recent documents and require a level of rigour that is not apparent in many of the business cases we saw in the course of our review.

3.2.2 Transmission Network Development Plan

Western Power's Transmission Network Development Plan (TNDP) sets out a ten-year plan for the capacity expansion of Western Power's transmission network. It provides a summary of the assumptions and methodologies that underpin the plan and a high level assessment is made, based on a measure of customers at risk, on the implications of deferring or not implementing the proposed plan.

Factors taken into account in developing the TNDP include:

- Technical Rules compliance;
- Load and generation forecasts;
- Strategic network objectives;
- The NIS and Network Management Plan (NMP) (see Section 3.2.3); and
- Western Power's broader commercial objectives

We consider the TNDP to be reasonably well detailed with a comprehensive focus on transmission planning over a ten-year horizon. In particular the TNDP introduces the concept of customers at risk in the event of identified future constraints not being addressed, but the document does not explain how this measure is calculated. Western Power has indicated that this is to be further developed – we support this as we think the measure has the potential to be incorporated into a broader and more structured risk management framework. The concept of customers at risk is discussed further in Section 7.2.7.

3.2.3 Network Management Plan

Western Power's Network Management Plan (NMP) provides comprehensive information on asset management strategies to meet network objectives, associated work plans, budgets and the approach to deliver these work plans. The primary output of the NMP is a rolling five-year maintenance program incorporating both opex and asset replacement capex for management of existing network assets (as opposed to the development of new assets).

Even though the NMP provided by Western Power was prepared specifically for the AA3 review, it covers a six year period (July 2011 to June 2017) and hence spans two access arrangement periods: the final year of AA2 (2011-12) and all five years of AA3 (2012-17).

The NMP is supported by a suite of asset management processes and IT systems that underpin Western Power's approach to network asset management. It is coordinated with other key strategies to optimise asset management investment decisions. The NMP is to form part of the annual planning cycle that allows integration of growth and non-growth investments.

The NMP is set in an environment of continuous improvement from which it is continuously refined through:

- Constant feedback through performance monitoring;

- Benchmarking of asset management strategies adopted by other utilities (through ITOMS[4], Electricity Networks Association etc); and

- Feedback from third party asset management system reviews.

The NMP is a key document in the broader asset management system. The plan is co-ordinated with the NIS and the TNDP to ensure asset management investment is optimised. It is implemented through the AWP, which is discussed in Section 3.2.4.

The NMP addresses the integration of the work plans for growth and non-growth projects and programs. It considers the interrelationship of various strategies in managing the network, including the impact of growth and non-growth capex on opex. While referencing these interrelationship elements, the document does not provide detail on how these inter-relationships are considered and managed within the business.

We noted that there was little information in the NMP on the management of SCADA and communications assets, even though these assets are explicitly covered by the plan[5].

3.2.4 Approved Work Program

The AWP is intended to provide a five-year view of the capex and opex projects, programs and activities for the network. It is refreshed annually and details the forecast expenditure over the five financial years following the year in which it is prepared. It considers the capital and maintenance investment forecast for the period, identifies the underlying assumptions that have been applied in its creation and outlines the prioritisation of investment. The AWP consolidates the outcomes from the NIS, TNDP and NMP and reflects an optimised, prioritised and constrained view, based on Western Power's optimisation and prioritisation processes and the funding and deliverability constraints that are forecast to exist during the AWP period.

Not all projects and programs contained in the AWP have individual approval at the business case level (although many in the early period of the AWP will). Rather, the investment stream as a whole is an approved 'current view' of the timing and level of investment necessary over the AWP period. All projects and programs in the AWP require individual business cases to be approved prior to execution.

Western Power also provided the 2011-12 work program annual submission to Government (January 2011) and initially suggested that it provided a view of the proposed network opex and capex for the 2011-12 to 2015-16 period, with the focus on 2011-12. On review, however, it is clear that the focus of this document is almost entirely on the 2011-12 period and Western Power subsequently advised that the document was focussed on that year and that the 2012-13 version of the document will cover a 5 year period. At the time of preparing the 2011-12 work program submission, Western Power's AA3 proposal was still being developed so expenditure requirements for AA3 were unclear.

The AWP for 2011-12 primarily addresses two key drivers:

- network investment and maintenance requirements; and

- deliverability of the work program.

Given the focus of the reviewed document is only on one year, we are unable to comment fully on the adequacy of the proposed AWP documents in supporting Western Power's ongoing management of expenditure during AA3. The current AWP does provide a comparison of forecast expenditure for 2011-12 at the time of the AA2 review with the currently proposed 2011-12 budget and provides some background into the differences. It also highlights how the transmission planning review undertaken in 2009-

4 ITOMS (International Transmission Operations and Maintenance Survey) is an independent biannual benchmarking analysis of international transmission network service providers undertaken by Utility Management Services (UMS) and funded by the participants. Western Power participated in the 2009 survey for the first time since disaggregation.

5 See Section 2.3 of the NMP.

10 deferred a number of projects and comments on how some of the deficiencies of AA2 governance processes are now being addressed. However, in terms of assisting us to assess Western Power's AA3 submission, the document is of limited value, given that it does not cover any of the AA3 period.

Western Power is planning to release its 2012-13 AWP in early 2012 and this will cover the full AA3 regulatory period. The document is an internal document that is approved by the Board and used to support the development of specific works development plan. It also forms a key part of Western Power's annual application to government for budgetary approval and funding. Funding has been an issue in past regulatory periods and clearly without sufficient funding Western Power will be unable to deliver on its proposed AA3 network plans.

3.2.5 Works Delivery Strategy

Western Power has prepared a Works Delivery Strategy (WDS) document as part of its AA3 submission noting that, in order to ensure that expenditure is prudent and efficient, it must be able to deliver projects and programs effectively. The overarching objective of the WDS is to ensure that the delivered work provides value for money for Western Power's customers, whilst also ensuring that Western Power achieves its service standard benchmarks. The WDS has been developed around divisional delivery strategies for the customer service, distribution and transmission divisions and explains how Western Power plans to ensure that implementation of the AA3 work program meets the following objectives:

- *efficiency* – maximising competition between external suppliers and fine-tuning internal processes to ensure Western Power's delivery method is efficient;

- *deliverability* – ensuring that an optimal mix of labour, materials and fleet is available so that the program will be delivered;

- *maintaining an in-house emergency response capability* – retaining a level of internal resource that can be mobilised quickly to respond to emergencies and ensure rapid fault restoration; and

- *building and retaining in-house expertise* – developing and retaining visibility and control of the works delivery program in-house to enable projects to be scoped and contracts managed effectively.

The strategies in the document build on some of the efficiencies that Western Power believes it achieved in AA2 (notwithstanding lower work volumes) and the document provides some benchmarking statistics to support this claim. The WDS also identifies the works delivery challenges for AA3 and outlines the specific strategies and tactics to address these - the most obvious of which is delivering a much bigger workload than was achieved in AA2.

Works delivery appears to be an ongoing problem for Western Power. Its AA2 access arrangement information included a comprehensive strategy to deliver a challenging works program. Nevertheless Western Power has indicated that some (but not all) of its under-expenditure in AA2 was due to an inability to deliver planned work in a timely manner, rather than the outcome of a deliberate strategy to reduce costs. This occurred notwithstanding the deferral of a significant number of planned large capex projects or programs and a global financial crisis that should have freed up resources from other sectors.

Western Power has recognised that this failure to deliver planned work volumes is of increasing concern to key stakeholders. Resolving these works delivery issues is recognised across the business as being a key objective for AA3 and the Board has taken an active interest in the situation. The Board formally approved Western Power's AA3 WDS at its 25th August 2011 meeting.

We believe that the AA3 WDS is well planned and structured and offers a realistic plan for the delivery of significantly higher work volumes. It recognises past issues with deliverability and includes strategies that specifically address the issues that arose during AA2 and the challenges that the increased work volumes of AA3 provide. Providing funding is made available to Western Power and unexpected situations such as a large delivery partner suddenly exiting the market do not arise, we consider the proposed AA3 work volumes can be achieved if the WDS is implemented as planned.

3.2.6 Works Program Governance Manual

The Works Program Governance Manual (WPGM) describes the framework for governing the planning, development and delivery of Western Power's network investments as reflected in the AWP. It describes the process to be followed and the key inputs, outputs and approvals required at each step in the process. It is intended to promote and ensure:

- prudent and efficient network investment decisions;
- a collaborative approach to planning, design and delivery with clearly defined, transitions, handover points and accountabilities;
- consistency of process leading to predictable and repeatable, outcomes; and
- full documentation of all decisions for transparency and auditability.

The framework is intended to apply to all investments in the network, including both network and non-network solutions and to all capex and opex projects and programs. It is primarily aimed at the functional level of governance, with the major focus being the work program as reflected in the AWP.

The document outlines the recently introduced seven phase / seven gate model (which is an extension of the previous six phase / six gate model referred to in the NIS and NMP documentation) that is referred to as the works program governance model. Specific sub-processes, actions and decisions are required during each phase. Between each phase there is a control gate with a set of deliverables and approvals that must be in place before the project or program can move to the next phase. The control gates that form part of the WPGM are designed to ensure investment options and assessments are efficient and undertaken at the appropriate time. The process also requires review and assessment at project or program completion to ensure feedback into the planning cycle.

The addition of the new phase 0 and gate 0 components of the Western Power model has only recently been tested in a pilot format. The pilot was successfully completed and Western Power is now in the process of embedding this revision into the WPGM. It expects the additional phase to be integrated as part of business as usual processes during the latter half of 2012. This further evidences the fact that many of the new governance elements are still very much work in progress.

We consider that the WPGM provides a sound framework for governance of the works program. The document and some process changes are still in their infancy although much of the governance framework is already embedded in the business. Western Power has also confirmed that throughout AA3 it will use the processes described in the manual. The model is not fully applicable to the AA3 forecast, particularly for projects in later years, which are still only in the very early phases of the project cycle.

3.3 IMPROVEMENTS SINCE AA2

The governance review undertaken as part of the AA2 review[6] identified a number of weaknesses in Western Power's governance of both capex and opex projects and programs. The report noted that significant progress had been made at the time in relation to AA1, especially in relation to the establishment of policies and procedures. It

[6] *Review of Expenditure Governance, Western Power;* Geoff Brown & Associates Ltd, 14 July 2009.

nevertheless highlighted significant concerns regarding the practical implementation of the governance principles.

This section of our report considers improvements that have been made subsequent to AA2 and also notes any deficiencies that are still observable as Western Power moves into the AA3 period. The section primarily considers the policy, procedural and process aspects as the application of governance to projects and programs is considered in more detail in our review of AA2 NFIT issues and AA3 capex and opex forecasts.

3.3.1 Works Program Management

3.3.1.1 Works Program Governance

The AA2 governance review commented on two specific issues associated with the AWP.

The report raised questions as to the merits of having an AWP that is updated around a three-year regulatory period when the environment in which Western Power operates is continually changing. The report also noted that Western Power now recognises this and reviews and updates the AWP annually. This is still the case. The AWP is now proposed to be implemented under a five-year rolling framework so that it will align with the new five-year regulatory period at least in the case of the 2012-13 AWP.

The report also noted a disconnect between the three-year planning period for the AWP and the rolling five-year horizon of the government budgetary planning process. The report considered that the governance would be improved if the two planning horizons were aligned and this would be achieved if the AWP had a five year horizon. This is being implemented. Furthermore, the length of each access arrangement period is now aligned with the Government's five year planning horizon.

3.3.1.2 Project Development and Implementation

The AA2 governance review noted that Western Power was developing a revised process for monitoring project implementation with key changes due to be introduced. The significant ones are noted below.

- The three-gate project development process was to be replaced by a six-gate process that extends right through to project completion;

- A works program office was to be created to monitor the progress of projects through the different gates of the implementation and delivery process and to provide support to project managers;

- There was to be greater use of software, business rules, templates and checklists to ensure a more consistent approach; and

- There was to be greater emphasis on cost management, risk assessment and quality assurance. For example there was to be a new requirement that all estimates over six months old must be "refreshed" before work proceeds.

During the course of our current review it was clear that the policies and procedures supporting all of these key changes had been introduced. However these processes are still evolving. For example, Western Power has recently introduced a seventh gate in the works program governance model but this has still to be incorporated in the NIS and NMP.

It is also not clear that these processes are always being applied. For example, Western Power's new facilities investment test (NFIT) pre approval application for the Mid West Energy Project (MWEP) did not include a recently updated or "refreshed" cost estimate and Western Power was not able to provide one when asked.

3.3.2 Program Management

As part of the AA2 review, a weakness in the application of the NFIT in the development of programs was identified. We note that this has been at least partially addressed in some of the procedures and policies that Western Power now utilises as part of its overall governance system. However some significant issues remain in terms of program management as evidenced by some of the issues discussed in Section 3.4 below.

The quality of program management will be a factor determining the efficiency of Western Power's AA3 expenditure. This applies in particular to addressing the significant maintenance backlogs and to the effectiveness of the response to a number of EnergySafety reports emphasising ongoing safety risks posed by the current state of the Western Power network.

3.4 ASSET MANAGEMENT SYSTEM

We reviewed the Asset Management System Review (AMSR) report[7] that was prepared by GHD Pty Ltd (GHD) on Western Power's transmission and distribution asset management systems. The AMSR was completed in accordance with the *Asset Management Systems Review Plan*, dated June 2011 and the Authority's *Audit Guidelines: Electricity, Gas, and Water Licences*, dated August 2010.

The review found that Western Power has continued to make progress in implementing various initiatives undertaken since the previous review. The main improvements by Western Power noted in the AMSR were:

- clear process flows from asset condition and fault analysis to capex and opex programs;
- monitoring and reporting of key performance parameters and asset data;
- continued mapping of key business processes;
- training and exercising of contingency and business continuity plans;
- improvements to the works planning process;
- introduction of field data capture to improve the efficiency and timeliness of data capture and planned work delivery;
- introduction of upgraded functionality in the corporate risk management software; and
- longer term planning of capex and opex through the future access arrangement forecasts.

Overall, Western Power's asset management system was found to be adequately defined and effectively performed. The following key recommendations came out of the review:

- The Wood Pole Inspection Guidelines section on non-pole asset elements (DMS# 5449945) should be expanded to include the non-pole inspection information on what is to be inspected and the assessment measurement protocols within the one document.
- Western Power should address the differences in the data reporting processes between its Distribution Facilities Management System (DFMS) and the alliance contractor records, and maintain monthly records of the pole inspection rates that can be verified from DFMS and contractors' invoice claims.

[7] *Western Power, Asset Management System Review, Final Report:* GHD Pty Ltd, October 2011.

- Western Power should develop a standard report to track the condemnation dates for Priority 1 and Priority 2 assessments against the new pole installation date to monitor its performance against its stated pole replacement timeliness targets.

The following aspects of the review were particularly relevant to the AA3 submission in that they raise concerns about the overall efficiency of Western Power's expenditure:

- An investigation into all wood pole failures during the 18 month review period and a random sample audit of 400 wood pole inspections found that the investigation could not verify that condemned poles had been replaced within the target timeframes. Additionally, the data on pole inspection backlogs was inconclusive in determining the size of the backlog, as the reporting capability of the current management systems could not generate this information and Western Power was unable to provide evidence that poles had been replaced within the required timeframes.

- An asset management system data extract provided evidence that 183,470 poles had been inspected during the 18 months audit period. As there are 630,000 distribution wood poles, each of which must be inspected once every four years, more than 248,250 poles should have been inspected to reduce the historical backlog on pole inspections. Western Power staff advised that all but 942 poles had been inspected in the last four years. Western Power provided data from two pole inspection contractors showing that 164,196 poles had been inspected between November 2009 and June 2010 and 126,122 poles between July 2010 and April 2011.

  The source data used was the monthly invoice claims for the two network contractors, which were independently checked by Western Power before payments were processed. The total number of inspections reportedly completed by the contractors during the review period was 290,318 and exceeded the target numbers needed to reduce a backlog. However, the difference between the contractors reported numbers of inspections (290,318) and that recorded in asset management system indicated that 106,848 pole reports had not been loaded into the asset management system. This indicates that 37% of inspections were not recorded in DFMS during the review period.

  A third source of data (Wood Pole Inspection Tracker (DM#7582098 and DM#6321838) shows that 258,565 poles were inspected during the audit period.

  Clearly, there is a significant issue in that three data sources do not align and that the asset management systems are not being kept up to date with inspection data. This suggests serious deficiencies in governance and associated process management. It was suggested by Western Power that the future Cognos data warehouse management system should address this problem in the next audit period by providing an auditable data source trail.

  We note that the AMSR report did not comment on the fact that Western Power does not have formal structured risk prioritisation incorporated into their asset management systems and processes.

3.5 IMPLEMENTATION AND EFFECTIVENESS OF GOVERNANCE PRINCIPLES AND PROCESSES

In considering how well governance principles are applied in practice we examined a number of projects and programs including both those implemented during AA2 and those proposed for implementation during AA3. In examining individual projects and programs we assessed the extent to which the governance processes ensure that projects and programs are identified and prioritised appropriately and that expenditure has been managed (AA2) and forecast (AA3) in an efficient and effective manner.

While we have commented on governance issues associated with individual projects and programs in Appendices A and B to this report, the sections below summarise our high level observations relating to the governance of projects and programs.

3.5.1 Risk Management

Western Power does not appear to have any structured or formal process in place to formally evaluate risks and prioritise projects and programs on the basis of risk. While, as part of its normal governance processes, all projects and programs are subjected to qualitative risk assessments, no structured process exists whereby these risk assessments are used to prioritise work or ensure that funds are allocated where they are most needed.

We sought additional information on this from Western Power and were advised:

> *Consideration of risk and relative risk is fundamental to the way Western Power develops its AWP and any subsequent need to adjust this in the event of funding or delivery constraints. However, Western Power does not explicitly use evaluated ratings to compare relative risk levels across operational and capital projects and programs to prioritise when there are competing needs.*
>
> *At the micro level, the individual projects and programs that comprise the AWP are identified in response to the network investment drivers as defined in the Network Investment Strategy.*
>
> *Network investment drivers are events, issues or factors that change the state of, or circumstances faced by, the network and apply 'pressure' to the network in terms of its ability to deliver desired network objectives. They can trigger an investment response if they result in a gap between actual or predicted state and desired future state relative to network objectives, depending on the risk that the gap presents and Western Power's acceptable level of risk.*
>
> *Thus projects/programs are initially considered for inclusion in the AWP based on the evaluated risk rating (which in turn is based on the risk associated with their underlying driver) as described in the response to the first question. In addition, each capital project or program considered for inclusion in the AWP is assessed for compliance with the New Facilities Investment Test (NFIT), with only those satisfying the NFIT being included.*
>
> *The final step in establishing the AWP is a consideration of the deliverability of constituent components. Only those projects and programs that are considered deliverable are included. Again, the evaluated risk ratings are used in determining which projects and programs (or elements of programs) are cut or deferred.*
>
> *Thus, the final AWP comprises projects and programs that respond to unacceptable risks, satisfy the NFIT (and hence are prudent and efficient), and are considered to be deliverable.*
>
> *This final AWP is available for scenario analysis if subsequent constraints (such as funding constraints) occur. Western Power responds to funding constraints as the need arises (for example in response to the difference between the ERA approved AA2 capital expenditure forecasts and the subsequent lower level of Government funding).*
>
> *Western Power's response to such constraints has been to use a cross functional, cross business team to review the AWP based on business knowledge, current business conditions, and taking into account risk and other considerations such as compliance issues and customer outcomes. In addition, the opportunity is taken to reassess NFIT compliance based on any newly available information (such as updated forecasts).*
>
> *The outcome of such a process preserves projects/programs that remain necessary under current business conditions and are driven by higher rated network risks. Projects / programs that are no longer necessary under current business conditions, or are driven by lower rated network risks are deferred or cancelled.*

The approach described above focuses on prioritisation of capital projects and programs, but also encompasses the impact of capital deferral on operating programs. In addition, it recognises that some opportunity for replanning may arise in light of constraints (e.g. selecting a shorter term / lower cost option).

This process has served Western Power well, particularly given that it is only required on a relatively infrequent basis. However, in the pursuit of continual improvement, Western Power is seeking greater efficiency through better integration with the AWP process, the network risk management process, and other surrounding processes. To this end, Western Power is developing a formal project and program evaluation and prioritisation methodology, referred to as the Strategic Investment Framework, which will be implemented in 2012. This will be supported by the new Network Risk Management Tool, which will also be implemented in 2012.

We consider that this explanation by Western Power confirms our assessment. The response indicates that some risk management processes are in place (as we would expect) but they are relatively unstructured, and tend to be qualitative and subjective. While risk assessments are required for all capital projects and programs, they appear to be used primarily to support business cases rather than as an integral part of the planning and prioritisation process. We think risk assessments could be better structured and used more effectively as a tool for prioritising expenditure.

Western Power recognises the deficiencies in its current risk assessment and prioritisation processes and is taking steps to address them. Good industry practice is for asset maintenance and replacement activities to be prioritised across asset classes using a CBRM approach. Each asset is given a "health index" based on its condition weighted by a quantitative assessment of the risk to the business should the asset fail. Assets are prioritised for maintenance on the basis of their health indices. Western Power does this for some individual asset classes but has still to extend this approach to directly compare the risk of asset failure across different asset classes.

3.5.2 Expenditure Planning

Many of the documents identified by Western Power as important to its expenditure governance processes, including the NIS, TNDP, NMP and the AWP, relate to expenditure planning. However, most of these documents appear to have been written primarily to provide a foundation for the preparation of the AA3 capex and maintenance forecasts and, apart from the AWP, we have seen no evidence that the documents formed part of the governance processes implemented during AA2. For example, the omission of SCADA and communications assets from the NMP suggests that this document is still in a formative stage of development. The only document that appears to be entrenched in Western Power's governance processes is the AWP, as this is required to be submitted annually to government to support the budget approval application; nevertheless there was some initial uncertainty within Western Power as to whether the 2011-12 plan covered a one or five year planning period.

We are not suggesting that the quality of the governance documents provided to us was poor, or that the preparation of these documents has not led to more efficient and cost effective AA3 expenditure forecasts. However, if the documents are to underpin Western Power's ongoing governance processes, they need to be reviewed annually and updated as necessary rather than prepared specifically to support regulatory period expenditure forecasts.

3.5.3 Option Identification and Analysis

We commented in Section 3.2.1 on weaknesses in Western Power's identification and evaluation of alternative options to meet a network development need. It is important that prospective options are properly researched and not summarily dismissed as impractical without proper consideration of the possibility of mitigating the issue. In particular, we think that do nothing or deferral options are sometimes dismissed too readily, with little meaningful supporting analysis. For example, business cases we have seen often discard such options with the only reason given being that they would result in Western Power failing to comply with the Technical Rules.

Western Power's transmission and distribution licences and the Technical Rules all require that Western Power design and maintain its network assets in accordance with good industry practice. Insisting that a project involving the construction of new assets must proceed in order simply to avoid a rules or licence non-compliance gives no consideration to the possibility that the funds might be better employed if they were used instead to address situations where, for example, the design or maintenance of existing assets is not in accordance with good industry practice, and where the risk to Western Power of letting this situation persist may be higher.

In many cases the only short term consequence of a regulatory non-compliance is an elevated risk that customers might not be supplied for a period if a network fault occurs at a time of peak demand. This risk may be small in comparison to other risks that Western Power might face in the event of an asset failure. We suggest that, if a business case does not include an objective evaluation of the potential consequences to Western Power or its stakeholders (including network users) if a project either does not proceed or is deferred, and does not include a discussion of any options available to mitigate that risk, then decision makers are not being provided with the information they need to ensure that the available funds are optimally employed for the benefit of the business and its stakeholders.

We appreciate that there are potential legal ramifications for regulatory non-compliances. However these can sometimes be mitigated. The Technical Rules, for example, provide for Western Power to seek a compliance exemption from the Authority and it may be that Western Power should be prepared to use this avenue in situations where non-compliance will allow better investment decisions to be made.

3.5.4 Asset Records

Effective asset management requires accurate records of the assets that exist on the network and the condition of these assets. Just as important is the accessibility of these records to the staff and contractors that need them. Many governance process failures that we have seen, or that have been brought to our attention, have arisen not because accurate records do not exist but because they have not been available or accessible when needed. Our reading of the GHD asset management audit report and the report of the Legislative Council Standing Committee on Public Administration bears this out. One problem appears to be difficulty in maintaining asset records on legacy systems and disparate decentralised databases that in many cases are duplicated and can't communicate with one another. Furthermore these records can be difficult to access and don't have the functionality to provide information in the form needed for optimal asset management decision making. A second problem is that information coming in from the field is not uploaded into these databases in a timely manner.

Western Power has historically devoted insufficient resources to the maintenance of its asset records and indications are that this problem persists. While asset data was first stored electronically in 1990, a data management team was not established until 2003. The business case for the pilot field survey data capture project undertaken during AA2 states:

> *The Data Management Section performs a data cleansing function that aims to resolve legacy data quality issues at the desktop. The data cleansing function is largely limited to correcting data based on validation of data business rules to cleanse the data.*
>
> *Where there is insufficient information available to determine the data with confidence, **the desktop cleansing activity is considered 'exhausted' and no further action is taken** [our emphasis]. The remaining assets require field verification to be cleansed.*
>
> *As of 2nd June 2010, there were 4,323 assets that contain a data error which cannot be corrected without field verification.*

In our view, data maintenance processes that simply ignore known asset errors that cannot be resolved without field inspection are completely inadequate. Data maintenance processes should include systems for proactively correcting errors that require field verification and field resources should be allocated to this as necessary. For example, linespersons with experience on Western Power's network but who are approaching retirement and no longer able to climb could be tasked with this work.

Western Power recognises the problems with its asset databases and is in the process of installing new IT systems under the strategic program of works (SPOW) initiative, which is discussed in Appendix A2 and Appendix B11. The integrated system for asset management (ISAM) and the Equipment and Works Management Data Warehouse (EWD) should address these issues. We note however, that the information provided to us on these new IT systems focuses on capabilities of the systems themselves, rather than how they might be used to improve the efficiency of, and achieve better outcomes from, the asset management effort. There is little indication, for example, that Western Power is planning to introduce a structured CBRM maintenance planning system similar to that now used by leading network service providers. We trust that, in developing and specifying its new IT systems, Western Power has looked beyond the need for accurate and accessible asset data and has specified systems that have the functionality to support continuing efforts to improve the efficiency and effectiveness of its asset management processes.

Western Power also recognises the issues surrounding data maintenance and is introducing a mobile workforce solution (MWS) that will allow asset information to be downloaded directly from the field. With this system, changes to the asset database and asset condition information will be uploaded in real time. We support this and note it should increase the efficiency of field operations and reduce many of the inaccuracies and delays resulting from manual uploading. Similar systems are used by leading network service providers in other jurisdictions. However, we caution that the MWS is unlikely to be a silver bullet that replaces the need for data maintenance support. As discussed in Appendix A2, Western Power has encountered significant problems introducing MWS on a pilot basis. We comment that, apart from the introduction of MWS, Western Power has provided very little information on how it proposes to strengthen its data management effort to ensure that data in the new IT systems continues to have the accuracy required for efficient asset management.

Western Power is proposing to address the issue of asset data inaccuracy through a $34 million field survey data capture project that appears to be the most comprehensive project of its kind ever undertaken by an Australian network service provider. This is discussed in Appendix B5 and Section 10.6.2.1. As discussed in these sections, we agree that data inaccuracy is a problem that needs to be addressed but are unconvinced that the expensive approach proposed by Western Power is needed. It may be that an alternative approach could produce a solution at the much lower cost that, while not fully satisfying everybody's "wish list", is nevertheless fit for purpose.

3.5.5 Distribution Planning

We noted in our review that Western Power does not have any documentation relating to distribution planning (particularly in relation to capacity expansion) analogous to the Transmission Network Development Plan.

Western Power indicated that, while it has a number of documents that reference elements of distribution system governance, its entire suite of governance and planning documents is subject to continuous refinement and in 2012-13 it is anticipated that Distribution and Transmission capacity expansion planning will be integrated to create a single Network Development Plan (NDP).

4. SERVICE LEVELS

4.1 AA2 SERVICE STANDARD BENCHMARKS

The AA2 access arrangement specified a number of quantitative serve level indicators that measure the quality of the reference services that Western Power provides. For each indicator the access arrangement provides a "benchmark" level of service that Western Power is expected to achieve. The sections below briefly describe the different service levels and compare Western Power's performance against the benchmark for the first two years of AA2.

4.1.1 Distribution Network

4.1.1.1 System Average Interruption Duration Indicator

The system average interruption duration indicator (SAIDI) is a measure of the total number of minutes without supply experienced in a twelve month period by an average user connected to the distribution network as a result of unplanned distribution network faults. The measure excludes interruptions caused by failure of the transmission system or other third party system, force majeure events and also interruptions caused during major storms or other events that stress the system beyond Western Power's capacity to mount an effective response[8]. SAIDI is a negative indicator in that a higher measure corresponds to reduced reliability and as such poorer network performance.

Benchmarks are specified for the network as a whole and also for different parts of the network, since it is not economic to provide the same level of service to users in rural areas as provided to users in central business district (CBD) and urban areas. The different network categories are the same as those used by the Australian Energy Regulator (AER) and are described in Table 4.1.

Table 4.1: Feeder Classifications

Category	Description
CBD	A feeder supplying predominantly commercial high-rise buildings supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
Urban	A feeder that is not a CBD feeder with actual maximum demand per total feeder length greater than 0.3 MVA per km.
Rural Short	A feeder that is not a CBD or urban feeder with a total feeder route length less than 200 km.
Rural Long	A feeder that is not a CBD or urban feeder with a total feeder route length greater than 200 km.

The AA2 benchmark SAIDI, and Western Power's actual performance for the first two years of the period, are shown in Table 4.2.

Table 4.2: AA2 SAIDI Performance (minutes)

	Network	CBD	Urban	Rural Short	Rural Long
2009-10 Benchmark	230	38	165	259	612
2009-10 Actual	**217**	**1**	**156**	**212**	**661**
2010-11 Benchmark	224	38	162	253	588
2010-11 Actual	**176**	**30**	**120**	**192**	**529**
2011-12 Benchmark	213	38	153	244	556

Source: Western Power

8 These are standard provisions in such arrangements. The purpose is to ensure that only events that are within the reasonable control of management are taken into account. Criteria specified in an international IEEE standard are used to assess whether interruptions resulting from a major storm of other event should be excluded.

The benchmarks reflected an expectation of a progressively improving level of reliability over AA2 and, apart from the CBD where the performance in 2009-10 could be considered an outlier, Western Power achieved this over the first two years of the period. Actual reliability was also better than benchmark on all measures, except for the rural long SAIDI in 2009-10.

4.1.1.2 System Average Interruption Frequency Indicator

The system average interruption frequency indicator (SAIFI) is a measure of the total number of interruptions experienced in a twelve month period by an average user connected to the distribution network as a result of unplanned distribution network faults. The exclusions that apply are the same as for SAIDI. Like SAIDI, SAIFI is a negative indicator in that a reducing number of interruptions reflects improving reliability.

The AA2 benchmark SAIFI, and Western Power's actual performance for the first two years of the period, are shown in Table 4.3.

Table 4.3: AA2 SAIFI Performance (Interruptions per year)

	Network	CBD	Urban	Rural Short	Rural Long
2009-10 Benchmark	2.50	0.24	1.92	3.12	5.00
2009-10 Actual	**2.00**	**0.02**	**1.55**	**2.33**	**4.17**
2010-11 Benchmark	2.46	0.24	1.89	3.06	4.85
2010-11 Actual	**1.76**	**0.23**	**1.31**	**2.11**	**3.86**
2011-12 Benchmark	2.41	0.24	1.83	2.98	4.80

Source: Western Power

Western Power has outperformed the SAIFI benchmark on all measures during the first two years of AA2 in what has been an excellent performance.

4.1.1.3 Customer Average Interruption Duration

The customer average interruption duration (CAIDI), or average length of each interruption, can be derived if SAIDI is divided by SAIFI. While this is not a benchmark indicator in the AA2 access arrangement, it is nevertheless a useful measure of how effectively a utility responds to an interruption once it occurs. Table 4.4 compares Western Power's average interruption duration with the benchmark level derived from the SAIDI and SAIFI AA2 access arrangement benchmarks. Like SAIDI and SAIFI, CAIDI is also a negative indicator.

Table 4.4: AA2 Average Interruption Durations (minutes)

	Network	CBD	Urban	Rural Short	Rural Long
2009-10 Benchmark	92	158	86	83	122
2009-10 Actual	**109**	**50**	**101**	**91**	**159**
2010-11 Benchmark	91	158	86	83	121
2010-11 Actual	100	130	92	91	137
2011-12 Benchmark	92	158	86	83	122

Source: Western Power

Table 4.4 indicates that, apart from the CBD, outage durations were generally longer than indicated by the SAIDI and SAIFI benchmarks and that, had reliability been measured in terms of SAIFI and CAIDI, Western Power's reliability performance would not have looked as good, at least superficially. This is because the improvement in SAIFI was not matched by a corresponding improvement in SAIDI.

We believe that CAIDI is a useful reliability indicator since management has a high level of control over the time it takes to restore supply once an interruption has occurred. We understand the AA2 benchmarks were based on Western Power's actual performance in the years prior to the start of AA2. If this is correct, then Western Power's response to an interruption after it occurs has deteriorated over time, although we acknowledge the improvement between 2009-10 and 2010-11.

4.1.2 Transmission Network

4.1.2.1 Circuit Availability

Transmission circuit availability is a measure of the percentage of the total number of hours in a year that an average transmission circuit is available for service. For the purposes of this measure, transmission circuits include those that form part of the transmission system provided they operate at 66 kV or above. Terminal station interconnecting transformers are included but zone substation supply transformers that form the interface between the transmission and distribution systems are not. Exclusions from this measure also include force majeure events and interruptions triggered by a third party. Unlike SAIDI and SAIFI, planned outages are included in the measure, although the duration of extended planned outages is capped at 14 days for measurement purposes. Hence the measure captures not only the reliability of the transmission assets, but also how effectively Western Power manages asset maintenance and transmission system augmentation planning.

It is also important to note that this indicator is not a direct measure of the service provided to users; since the redundancy built into the transmission system ensures that supply to users is generally maintained when a transmission circuit is out of service. However, if this redundant capacity is not available at any time, there is a higher risk that an unplanned network outage will cause a loss of supply to users so circuit availability is indicative of the risk of non-supply.

Circuit availability is a positive indicator in that better performance will result in a higher measure.

Table 4.5 compares Western Power's transmission circuit availability for the first two years of AA2 with the availability benchmarks in the AA2 access arrangement. Availability was comfortably above the benchmark in 2009-10 and marginally below it in 2010-11. However this needs to be viewed in the context of the reduced capex and opex over AA2, which would suggest that the number of planned outages has been lower than anticipated when the benchmarks were set.

Table 4.5: AA2 Transmission Circuit Availability

	Network
2009-10 Benchmark	98.0%
2009-10 Actual	**98.4%**
2010-11 Benchmark	98.0%
2010-11 Actual	**97.9%**
2011-12 Benchmark	98.0%

Source: Western Power

4.1.2.2 System Minutes Interrupted

System minutes interrupted is a measure of the total energy not supplied as a consequence of faults on the transmission network. In calculating the measure, the total energy not supplied as a result of transmission network interruptions is estimated, based on the actual demand at the time of the interruption. The system minutes are then assessed as the length of a total transmission system shutdown at the time of peak demand for the transmission system to not deliver an equivalent amount of energy.

Outages due to a force majeure event or caused by a third party are not included in the measure[9].

System minutes interrupted is a negative indicator in that a lower measure indicates better performance.

The AA2 access arrangement includes "two system minutes interrupted" benchmarks, one for the shared transmission network and one for the radial network. Table 4.6 compares Western Power's actual performance in the first two years of AA2 with the access arrangement benchmarks.

Table 4.6: AA2 Transmission System Minutes Interrupted (minutes)

	Meshed Network	Radial Network
2009-10 Benchmark	9.3	1.4
2009-10 Actual	**8.9**	**0.8**
2010-11 Benchmark	9.3	1.4
2010-11 Actual	**6.7**	**4.8**
2011-12 Benchmark	9.3	1.4

Source: Western Power

It can be seen that Western Power achieved its benchmark service levels, except for the radial network in 2010-11, where it underperformed by a significant margin. This was due to a pole top fire, on the single circuit Merredin-Carrabin-Yerbillon-Southern Cross 66 kV line, which resulted in a loss of 3.45 system minutes. Except for this one event, Western Power would have performed within its benchmark level.

4.1.2.3 Loss of Supply Events

Loss of supply events is a measure of the number of events on the transmission system that cause a loss of supply. Exclusions are similar to the system minutes interrupted indicator except in this case planned supply interruptions are not included. The indicator is categorised into events with an impact of greater than 0.1 system minute and events with an impact greater than 1 system minute.

Table 4.7 compares Western Power's actual performance in the first two years of AA2 with the access arrangement benchmarks.

Table 4.7: AA2 Transmission System Loss of Supply Events (no.)

	>0.1 System Minute	>1 System Minute
2009-10 Benchmark	25	2
2009-10 Actual	**27**	**2**
2010-11 Benchmark	25	2
2010-11 Actual	**18**	**1**
2011-12 Benchmark	25	2

Source: Western Power

It can be seen that in the first two years of AA2, Western Power has matched or outperformed its benchmark performance for three of the four available measures. The relatively minor below-benchmark performance in 2009-10 appears to be due to unreliable protection schemes causing partial blackouts of substations within the CBD and Goldfields area. Western Power plans to address this problem during AA3.

9 Western Power has indicated to us that the measured system minutes interrupted in Table 4.6 does not include the impact of planned supply interruptions. The definition on p8 of the approved AA2 access arrangement appears to limit the measure to "outages for forced and emergency events" but, unlike other access arrangement definitions, does not explicitly exclude planned outages.

4.1.2.4 *Average Outage Duration*

The average outage duration measures the average duration of unplanned transmission system outages, irrespective of whether or not the outage results in a loss of supply. The exclusions that apply to system minutes interrupted and loss of supply events also apply, and the duration of any outage is capped at 14 days. Average outage duration is a negative indicator in that a lower measure indicates better performance. The indicator is similar to CAIDI, as discussed in Section 4.1.1.3 in relation to the distribution system, in that it measures the effectiveness of Western Power's response to an incident after it has occurred.

Table 4.8 compares Western Power's transmission system average outage duration for the first two years of AA2 with the benchmarks in the AA2 access arrangement.

Table 4.8: AA2 Transmission System Average Outage Duration (minutes)

	Network
2009-10 Benchmark	764
2009-10 Actual	**679**
2010-11 Benchmark	764
2010-11 Actual	**675**
2011-12 Benchmark	764

Source: Western Power

It can be seen from Table 4.8 that Western Power has out-performed the access arrangement benchmark in each of the first two years of AA2.

4.1.3 Street Light Repair Time

The final service level benchmark included in the AA2 Access Arrangement is the time to repair street lights after Western Power is notified that a light is out of service. Western Power's performance compared to the access arrangement benchmarks is shown in Table 4.9.

Table 4.9: Street Light Repair Time (days)

	Perth Metropolitan Area	**Major Regional Towns**	**Remote and Rural Towns**
2009-10 Benchmark	5.0	5	9
2009-10 Actual	**2.0**	**2.0**	**1.7**
2010-11 Benchmark	5	5	9
2010-11 Actual	**1.4**	**1.5**	**1.7**
2011-12 Benchmark	5	5	9

Source: Western Power

4.2 SETTING AA3 BENCHMARK SERVICE LEVELS

In the first two years of AA2, Western Power has performed well against the service level benchmarks in the access arrangement, notwithstanding its underspend on both capex and opex. Of the 38 actual measures reported above[10] Western Power failed to meet the benchmark level on only four assessments, an achievement rate of almost 90%. We think this is an excellent performance.

Notwithstanding this creditable performance, these four failures to meet the benchmark service level put Western Power is in breach of clause 11.1 of the Access Code, which states:

[10] This does not include CAIDI, which was not a formal AA2 benchmark indicator.

> *A service provider must provide reference services at a service standard* ***at least equivalent*** [our emphasis] *to the service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.*

In its AA3 access arrangement information Western Power argues that the four failures to meet its service level benchmarks puts it in breach of its transmission and distribution licences, which both require compliance with the Access Code, and that these licence non-compliances could potentially have serious consequences. It also notes that these non-compliances have rendered the gain sharing mechanism in the access arrangement ineffective due to clause 5.14C in the AA2 access arrangement which states:

> *In any year in which an above-benchmark surplus is calculated to be a positive value but Western Power fails to meet service standard benchmarks for that year, the above benchmark surplus for that year is deemed to be zero.*

While, as noted above, Western Power's performance against its benchmarks was, in our view, excellent it failed to meet at least one benchmark service level in each year and so the gain sharing mechanism in the access arrangement will not apply in respect of either of the first two years of AA2[11]. Over the first two years of AA2, Western Power underspent its approved opex by almost 10%. Given the design of the gain sharing mechanism, it should have been able to carry over this saving until 2015-16. In a situation where its overall reliability improved notwithstanding the reduced level of opex, it does not seem reasonable that it should be prevented from realising the benefits of this efficiency gain when it failed to meet just four of 38 benchmark service levels over the two year period. In this context we note that the benchmarks appear to have originally been set on the basis of an expected probability of achievement of only 50%.

To minimise the risk of this situation reoccurring during AA3, Western Power has proposed that its service standard benchmarks be reduced to the minimum level of service that it expects to be able to provide for each service level performance measure. It has therefore proposed benchmarks at a level where, based on its historic performance over the five years period ending 30 June 2011, it calculates the probability of not achieving the benchmark service level to be only 2.5%[12].

We are concerned about this proposal since such benchmarks do not provide an indication of the average service levels that network users should expect to receive. Under clause 5.6 of the Access Code a service standard benchmark must be (a) reasonable and (b) sufficiently detailed and complete to enable a user to determine the value represented by the reference service at the reference tariff. In our view the benchmark levels proposed by Western Power are so low that they do not meet this intent. In particular they do not allow an accurate assessment of the value represented by a reference service at the reference tariff. We consider that the average service levels provided over time are a more meaningful benchmark to use for assessing this value proposition. In our view using a minimum service standard, which Western Power can expect to exceed 97.5% of the time and usually by a significant margin, is not useful for this purpose.

In the following sections of this report we have followed the AA2 precedent and estimated the service levels that we consider fairly reflect the level of service that Western Power is currently providing. In our view these provide more meaningful benchmarks against which to assess Western Power's performance.

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11 This applies only to the carryover of the efficiency gain into AA3, in accordance with clause 5.14D of the AA2 access arrangement. Western Power underspent its allowed opex for 2011/12 yet the revenue it was been allowed is sufficient to fully fund the allowed expenditure. As there is no adjustment mechanism relating to opex, it will be allowed to retain the difference between what was allowed and what it actually spent.

12 In order to provide sufficient points for a meaningful statistical analysis, Western Power has used monthly data points where each point is the value of the performance indicator for the previous 12 months (i.e. a rolling twelve month average). Hence 60 data points were used for each analysis, which took into account actual service levels over a total period of six years.

4.3 AA3 SERVICE LEVEL PERFORMANCE INDICATORS

Western Power has proposed a new suite of benchmarked access arrangement performance indicators for AA3. It argues that clause 5.1(c) of the Access Code requires a service standard benchmark to relate to the performance of a reference service and that during AA2 the reference services and service level benchmarks were not well aligned. However it will continue to measure and report on the performance of all service level indicators that were benchmarked in AA2.

For service level measures included in the AA3 access arrangement, Western Power proposes two key performance indicators:

- A service level *benchmark*. As discussed in Section 4.2 the service level benchmark is the minimum level of service that Western Power will be legally required to provide. The benchmark proposed for each performance indicator is set at a level that Western Power expects to provide 97.5% of the time.

- A service level *target.* Targets are proposed only for the subset of service level measures that are included in the service standard adjustment mechanism (SSAM). The targets reflect the level of service that Western Power expects to provide on average and has generally been set at a level that Western Power expects to better 50% of the time, based on a statistical analysis of its measured performance over the five years up to 30 June 2011.

Unlike AA2, where distribution system benchmarks reflected a progressive improvement in performance over the period, in AA3 Western Power proposes the same benchmarks and targets for each year of the period for all measures. This is because it has not provided for any capex on distribution network reliability improvement initiatives[13]. We consider this reasonable given there appears to be no widespread dissatisfaction with the average level of service currently provided and no indication that customers would be prepared to pay more for improved service levels.

The sections below discuss the new service level measures proposed by Western Power and the benchmarks and SSAM targets proposed. Consistent with the discussion in Section 4.2, our proposed performance benchmarks for the AA3 access arrangement are set at the level that we think users should receive on average in any year of the AA3 period. On this basis there would be no difference in the benchmark and SSAM target service level performance standards.

4.3.1 Distribution Reference Services

4.3.1.1 SAIDI & SAIFI

For AA3, Western Power has proposed the following changes to the benchmarked SAIDI and SAIFI indicators included in the AA2 access arrangements.

- The overall network SAIDI and SAIFI will not be retained as a benchmarked indicator. We agree with this, as the SAIDI for different parts of the network better reflect the service levels different users can expect to receive.

- In measuring SAIDI and SAIFI for different parts of the network, Western Power now plans to include interruptions caused by unplanned transmission network faults. Hence the reported SAIDI and SAIFI will generally be higher than the corresponding SAIDI measured in AA2, but will better reflect the service levels as perceived by users. This is because when a user experiences a supply interruption, the cause of the interruption does not mitigate the inconvenience experienced.

[13] As discussed in Section 8.6.5, Western Power is planning to spend, on average, $8.3 million a year during AA3 on capex projects designed to reduce the number of customers experiencing outages of more than 12 hours. The impact of this expenditure on the access arrangement service level measures is expected to be small.

Western Power's proposed AA3 benchmarks and SSAM targets, together with its actual SAIDI and SAIFI for each of the last five years, is given in Tables 4.10 and 4.11. For comparison, the equivalent measure excluding the impact of transmission faults is also provided.

Table 4.10: Proposed AA3 SAIDI (minutes)

	AA3 Proposed		Actual Performance						
	Benchmark	SSAM Target	2006-07	2007-08	2008-09	2009-10	2010-11	Average 2006-11	Average 2008-11
CBD									
Including Transmission	56	28	33	51	28	3	31	29	30[1]
Excluding transmission	-	-	33	51	28	1	30	29	29[1]
Urban									
Including Transmission	200	163	152	177	166	173	130	160	157
Excluding transmission	-	-	142	165	158	156	120	148	145
Rural Short									
Including Transmission	360	254	334	267	251	225	198	255	225
Excluding transmission	-	-	329	260	238	212	192	246	214
Rural Long									
Including Transmission	720	616	642	634	584	688	551	620	608
Excluding transmission	-	-	624	611	573	661	529	600	588

Note 1: Performance in 2009-10 treated as an outlier and excluded.
Source: Western Power and GBA analysis.

Table 4.11: Proposed AA3 SAIFI (interruptions)

	AA3 Proposed		Actual Performance						
	Benchmark	SSAM Target	2006-07	2007-08	2008-09	2009-10	2010-11	Average 2006-11	Average 2008-11
CBD									
Including Transmission	0.40	0.22	0.25	0.22	0.15	0.21	0.32	0.23	0.23
Excluding transmission	-	-	0.25	0.22	0.15	0.02	0.23	0.18	0.19[1]
Urban									
Including Transmission	2.30	1.90	2.00	2.18	1.79	1.76	1.52	1.85	1.69
Excluding transmission	-	-	1.80	1.91	1.65	1.55	1.31	1.64	1.50
Rural Short									
Including Transmission	4.20	2.91	3.94	3.20	2.89	2.54	2.28	2.97	2.57
Excluding transmission	-	-	3.79	3.13	2.70	2.33	2.11	2.81	2.38
Rural Long									
Including Transmission	5.70	4.77	5.00	5.42	4.57	4.71	4.15	4.77	4.47
Excluding transmission	-	-	4.72	4.99	4.27	4.17	3.86	4.40	4.10

Note 1: Performance in 2009-10 treated as an outlier and excluded.
Source: Western Power and GBA analysis.

The statistical algorithm used by Western Power to calculate its proposed AA3 SSAM targets was complex. We considered that if this algorithm was valid it would give a result similar to a simple average of the numbers shown in Tables 4.10 and 4.11. This was indeed the case and we accept the validity of the statistical approach used by Western Power to calculate its targets. However, our preference is to avoid complex statistical analysis and use an approach that is more transparent and can be readily understood by users. Given the small difference between the statistical analysis results and the results found using a simple average, we see little value in the more complex analysis. We have therefore proposed benchmark/SSAM target levels that have been calculated using a simple average.

In basing its targets on a five-year history Western Power is giving less weight to the recent reliability improvements that have resulted from the reliability capex projects and procedural improvements that it has implemented in more recent times. The effect of these is real as can be seen from a comparison of the three- and five-year averages in Tables 4.10 and 4.11. We believe that these benefits will be sustained into AA3 and that they should therefore be reflected in more challenging benchmarks/SSAM targets.

We therefore suggest that the AA3 access arrangement benchmarks/SSAM targets be set on the basis of the average performance over the three year period between 1 July 2008 and 30 June 2011. Western Power could argue that service levels are influenced by unpredictable environmental factors over which it has no control and therefore the measurements are sufficiently volatile to make a three year history statistically unreliable. There is some merit in this argument. Nevertheless, given the significant performance improvement in the last three years and the improvement in Western Power's business processes and asset management over this time, we are satisfied that benchmarks and SSAM targets based on a three year average are more indicative of Western Power's likely service levels during AA3.

4.3.1.2 Call Centre Performance

Western Power is proposing to introduce call centre performance as a new benchmarked service standard measure related to the provision of distribution reference services and also to incorporate this measure into the SSAM. It engaged KPMG to undertake a survey of users' perceptions with regard to supply reliability. KPMG found that a significant number of users surveyed had used the call centre to report a supply interruption and that, while call centre performance did not change customers' perceptions about the reliability of their power supply, it did have an impact on perceptions regarding the manner in which Western Power responded to the problem.

The inclusion of customer service components is common in similar performance monitoring schemes in other jurisdictions. Call centre performance is one of the performance indicators in the AER's distribution service target performance incentive scheme (DSTPIS)[14]. The performance measure proposed by Western Power is the percentage of calls answered, either by an operator, or by a recorded message providing substantive information, within 30 seconds. This is less stringent than the definition used in the DSTPIS[15], although the basic measure, percentage of calls answered within 30 seconds is the same and is standard in the industry.

Historic call centre performance and Western Power's proposed AA3 target are shown in Table 4.12.

Table 4.12: Call Centre Performance

AA3 Proposed		Actual Performance						
Benchmark	**SSAM Target**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**Average 2006-11**	**Average 2008-11**
75.0%	88.0%	94.4%	87.4%	87.0%	89.0%	83.8%	88.3%	86.6%

Source: Western Power and GBA analysis.

There appears to have been a significant deterioration in call centre performance in 2010-11 and this has reduced the three year average performance below the longer term average. The reason for this deterioration in performance is unknown. However Western Power commissioned a new call centre using state of the art technology in time for the commencement of 2009-10 and it would be a rather perverse outcome if teething problems with the operation of this new equipment were passed through in the form of a less onerous performance target in the AA3 access arrangement. We therefore consider the AA3 target proposed by Western Power to be reasonable.

4.3.2 Transmission Reference Service

The AA2 access arrangement included the following six benchmarked performance indicators relating to the quality of service provided by the transmission network. Of these, only circuit availability was included in the SSAM.

- Circuit availability;
- System minutes not supplied – meshed network;
- System minutes not supplied – radial network;
- Number of interruptions greater than 1 system minute;

[14] *Electricity Distribution Network Service Providers, Service Target Performance Incentive Scheme*; AER, November 2009.

[15] The DSTIPS definition includes the total time taken to connect a caller to an operator, excluding any time a caller is connected to an automated response system providing substantive information. It appears to be based on the premise that all callers are entitled to be put through to an operator within a reasonable time. We consider the STIPS definition to be particularly valid for a faults service because it provides for callers wanting to report information on the cause of a fault.

- Number of interruptions greater than 0.1 system minute;
- Average interruption duration.

In AA3 Western Power is proposing to retain only circuit availability as a benchmarked performance indicator. It is also proposing a new benchmarked transmission customer service indicator that it calls an individual customer service measure, which will not be included in the SSAM.

In its AA3 access arrangement information, Western Power justifies this change in approach on the following basis:

- Section 5.1(c) of the Access Code requires benchmarked performance indicators to be linked to a reference service;
- Western Power is unique amongst Australian electricity lines businesses in that it is an integrated transmission and distribution business. It is not a standalone transmission service provider that provides a transmission service to external electricity distributors;
- Western Power has a relatively small number of customers receiving a transmission reference service and the number of service interruptions that these individual customers experience is very low. It is therefore difficult to set a minimum service standard relevant to these customers;
- Given Western Power's unique position as an integrated network service provider, it is not necessarily appropriate that it should be assessed using the same performance indicators that are commonly used to assess other transmission or distribution service providers; and
- Western Power will continue to measure and report on its performance against all indicators, irrespective of whether or not they form part of the AA3 access arrangement.

The transmission network is an important part of Western Power's asset base and comprises 40% of fixed assets by value. It is also the network into which the majority of the electricity delivered to consumers is injected. We therefore consider it important that the service levels provided by the transmission network are appropriately benchmarked as part of the access arrangement.

Neither of the performance indicators that Western Power proposes to retain achieves this. Availability is a measure of the quality of Western Power's stewardship of its transmission assets but it is not a measure of the level of service that these assets provide. An asset base with full redundancy and an availability of 50% will provide exactly the same service level as an asset base with no redundancy and an availability of 100%. Similarly, Western Power's proposed a new individual customer service performance indicator, which is discussed in Section 4.3.2.2, is a measure that is unrelated to the level of service provided by the transmission asset base.

Western Power's argument that it is not possible to set a reasonable benchmark that is relevant to external customers connected directly to the transmission network is premised on its position that the benchmark should be the minimum level of service that it is obliged to provide and if it failed to provide this level of service it would be in breach of its transmission licence. This is discussed in Section 4.2.

We do think, however, that Western Power's rationale for not including system minutes not supplied as a benchmarked performance measure in the AA3 access arrangement has merit. The majority of the electricity delivered to consumers through the Western Power network is delivered through the distribution network. As system minutes not supplied is a power delivery measure, and as transmission network interruptions are now proposed to be incorporated into the revised definitions of SAIDI and SAIFI, the system minutes not supplied performance indicators add little additional value. We concur with Western Power's proposal that they not form part of the access arrangement.

However the number of interruptions and average interruption duration performance measures relate directly to the performance of the transmission network and in particular how this performance impacts directly connected customers. We think these performance indicators should be retained and have proposed appropriate benchmarks in the sections below.

4.3.2.1 Circuit Availability

Western Power's historic circuit availability is compared with its proposed AA3 target in Table 4.13.

Table 4.13: Circuit Availability

AA3 Proposed		Actual Performance						
Benchmark	**SSAM Target**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**Average 2006-11**	**Average 2008-11**
97.3%	97.7%	98.0%	98.4%	98.3%	98.4%	97.9%	98.2%	98.2%

Source: Western Power and GBA analysis.

Western Power's proposed circuit availability target has incorporated an availability reduction of 0.5% below the average historic performance to account for the additional circuits that Western Power believes will not be available due to its proposed work program.

During the review we asked Western Power for further information on how it calculated this additional 0.5% reduction and in response it provided an analysis as to how it forecast circuit availability. As shown in Table 4.14 the major contributor to circuit unavailability is planned outages for maintenance work, including maintenance driven capex such as pole replacements. The impact of one-off capacity expansion projects and unplanned interruptions is much less significant. However there appeared to be inconsistencies in the numbers used by Western Power and we were unable to reproduce Western Power's forecast availability using the input numbers provided.

We have adjusted Western Power's figures to remove outage days attributed to transformer replacement. Western Power has confirmed that these outage days do not relate to the maintenance or replacement of zone substation transformers but cover non-routine maintenance work, presumably on terminal station transformers and associated equipment. We think the estimated outage time is excessive in comparison to other planned transmission outage causes, given the limited number of terminal station transformers on the network. We also note that Western Power has incorrectly classified this work as capacity expansion.

Table 4.14: compares our analysis of AA3 forecast circuit availability with the Western Power forecast. This analysis indicates that retention of the AA2 benchmark availability of 98.0% is appropriate. Given that capacity expansion projects are driven by demand, we also considered whether a change in the rate of implementation of these projects would have an impact on availability. However, given that the overall impact of capacity expansion outages on the measure is relatively minor and that capacity expansion will also impact the normalising factor of available circuit-days, we concluded that any impact would be small.

Table 4.14: Forecast Circuit Availability

	2012-13	2012-14	2014-15	2015-16	2016-17	Average 2002-17
Available circuit days	**88,094**	**88,277**	**89,924**	**90,656**	**92,303**	
Outage circuit days						
Unplanned	79	79	81	82	83	
Planned - capacity expansion projects	63	49	91	63	140	
Maintenance	1,563	1,615	1,666	1,724	1,721	
Subtotal	1,705	1,743	1,838	1,869	1,944	
Less adjustments for substation transformer replacements.	28	28	28	28	28	
Total outage circuit days	**1,677**	**1,715**	**1,810**	**1,841**	**1,916**	
Availability	**98.10%**	**98.06%**	**97.99%**	**97.97%**	**97.92%**	**98.01%**
Western Power forecast	97.83%	97.79%	97.72%	97.70%	97.65%	97.74%

Source: Western Power and GBA analysis.

4.3.2.2 Individual Customer Service

Western Power has proposed a new individual transmission customer service performance measure for AA3. It believes that this performance measure will provide a strong incentive to provide high-quality customer service to Western Power's directly connected transmission customers.

The new measure will require that each transmission-connected customer has:

- an account manager who will provide a direct point of contact within Western Power;
- an annually reviewed customer service management plan that reflects the individual needs of the customer; and
- the opportunity to participate in an annual customer satisfaction survey, which would provide an opportunity for customers to provide their feedback and enable Western Power to measure each customer's service experience.

The proposed benchmark level would be 100% compliance.

Western Power has tested the new customer service measure with its transmission-connected customers and they were supportive. Its feedback shows they would support a more customised measure and reporting for individual customers. They would be particularly interested in being able to set a scaled benchmark level for the customer satisfaction survey.

The proposed new customer service measure relates to the service currently provided to 52 key external customers. Given the importance of these customers to Western Power, and its core value of respecting its customers by staying connected to them to achieve the best energy solutions[16], we are surprised that Western Power considers a performance measure of this nature is needed. We would have thought an account manager for each transmission customer together with an annually reviewed customer service management plan would already be established business practice.

[16] Western Power's Statement of Corporate Intent 2011-12, p5.

We also note that, unlike other benchmarked performance measures, the proposed indicator does not measure Western Power's response to situations over which it does not have full control. In this case, Western Power's performance against this measure is fully within its control and, given the small number of customers, full compliance is possible using minimal resources. This is reflected in the proposed benchmark of 100% compliance.

We see little value in including this performance measure in the AA3 access arrangement.

4.3.2.3 Other AA2 Transmission Performance Indicators

Western Power's historic performance for the performance indicators that were included in the AA2 access arrangement but that Western Power proposes not be retained for AA3 is shown in Table 4.15.

Table 4.15: Performance against AA2 Indicators

	2006-07	2007-08	2008-09	2009-10	2010-11	Average 2006-11	Average 2008-11
System minutes interrupted (meshed)	14.2	8.8	7.6	8.9	6.7	9.2	7.7
System minutes interrupted (radial)	1.4	1.8	2.0	0.8	4.8	2.2	2.5
No of interruptions > 0.1 system minute	30	27	18	27	18	24	21
No of interruptions > 1 system minute	3	2	3	2	1	2	2
Average interruption duration (minutes)	834	715	501	679	675	681	618

Source: Western Power and GBA analysis.

As discussed in Section 4.3.2, we see little value in retaining the system minutes interrupted performance indicators given that they are a measure of the delivery of power to consumers and also that Western Power proposes to modify the definitions of its SAIDI and SAIFI indicators to include the impact of transmission system interruptions.

However we consider that the other measures should be retained as benchmarked measures in the AA3 access arrangement. We also note the performance improvement seen in these three measures in the latter years of the five year review period. This is likely to be due in large measure to the efforts made by Western Power during AA1 and AA2 to improve reliability. We think this improved performance should be reflected in the AA3 access arrangement and therefore suggest that the AA3 access arrangement benchmarks for these three measures be the average performance over the three year period 2008-11, as shown in Table 4.15.

4.3.3 Streetlight Repair Time

Western Power is proposing to retain two of the three benchmarked performance measures in the AA2 access arrangement. These are:

- street lighting repair times – metropolitan areas
- street lighting repair times – regional areas

The third benchmarked performance measure in the AA2 access arrangement, "street lighting repair times – major regional towns" will be incorporated in the 'street lighting repair times – metropolitan areas' performance measure. This more closely reflects the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008*, which only requires reporting in two categories – metropolitan and regional areas. We see the logic in this.

Western Power's actual performance against the two indicators is shown in Table 4.16.

Table 4.16: Streetlight Repair Times

	Proposed AA3 Benchmark	Actual Performance						
		2006-07	2007-08	2008-09	2009-10	2010-11	Average 2006-11	Average 2008-11
Metropolitan Areas	5	7.2	9.6	3.7	2.0	1.4	4.8	2.4
Regional Areas	9	5.7	5.6	4.1	1.7	1.7	3.8	2.5

Source: Western Power and GBA analysis.

There has been a substantial improvement in Western Power's performance in AA2, and given the high level of control that Western Power has over this outcome, there is no reason why this improvement cannot be sustained. We therefore suggest that the benchmarks in the AA3 access arrangement be the average repair times achieved over the period 2008-11, as shown in Table 4.16.

4.4 SERVICE STANDARD ADJUSTMENT MECHANISM

4.4.1 Introduction

The SSAM provides Western Power with a reward when its service levels are higher than expected and a penalty when service levels are lower than the expected level. The main objective of the SSAM is to mitigate the risk that, in seeking to capture and retain efficiency gains through the gain sharing mechanism, Western Power allows the level of service it provides to its network users to deteriorate. Under the SSAM it would be penalised for doing this.

As in AA2, in AA3 Western Power is proposing that only a subset of its benchmarked service level performance indicators be included in the SSAM. These are:

Distribution

- SAIDI (CBD, urban, rural long and rural short);
- SAIFI (CBD, urban, rural long and rural short); and
- Call centre performance.

Transmission

- Availability.

These measures are the same as in AA2, except for the addition of call centre performance, which is currently neither a benchmarked nor SSAM measure and the exclusion of the two system minutes interrupted performance measures. As in AA2, SAIDI and SAIFI would be measured separately for CBD, urban, rural short and rural long parts of the network.

Key parameters of the SSAM are the expected or target service levels and the incentive rates. The incentive rates determine the amount of the reward or penalty that applies to a given level of service.

4.4.2 Target Service Levels

Western Power has proposed that the target service levels for the SSAM be set on the basis that during AA3 the expected probability of a particular service level target being exceeded in a given year is 50%. We agree with this approach as it represents the average service levels that network users can expect. If the target service levels are accurately set then the expectation is that any rewards in one year will be offset by penalties in other years and the overall revenue impact of the scheme should be approximately neutral.

We consider that the SSAM target set on this basis should be the same as the benchmark levels for the relevant performance measure, as proposed by us in Section 4.3. These are summarised in Table 4.17 and compared with the targets proposed by Western Power. For each measure Table 4.17 also shows the SSAM targets for 2011-12 in the AA2 access arrangement. It should be noted that the 2011-12 SAIDI and SAIFI targets shown in Table 4.17 are not directly comparable with the corresponding targets for AA3, which include the impact of unplanned transmission network outages. The effect that these additional outages have on the performance measures can be seen from Tables 4.10 and 4.11.

Table 4.17: SSAM Targets

	2011-12 SSAM Target[1]	Western Power Proposed AA3 Target	GBA Proposed AA3 Target
SAIDI (minutes)			
CBD	38	28	30
Urban	153	163	157
Rural Short	244	254	225
Rural Long	556	616	608
SAIFI (interruptions per year)			
CBD	0.24	0.22	0.23
Urban	1.83	1.90	1.69
Rural Short	2.98	2.91	2.57
Rural Long	4.80	4.77	4.47
Other			
Call Centre Performance	-	88.0	88.0
Transmission Circuit Availability	98.0%	97.7%	98.0%

Note 1: SAIDI and SAIFI targets exclude impact of unplanned transmission system outages.
Source: Western Power and GBA analysis.

In AA2 the targets for distribution indicators changed from year to year to reflect expected improvements in reliability as a result of reliability targeted capex. In AA3 Western Power has not included similar reliability targeted capex in its access arrangement[17] and is aiming to maintain its service levels at their current level. Hence it is proposing SSAM targets be the same for each year of the regulatory period.

4.4.3 SSAM Incentive Rates

The second key parameter in the design of the SSAM is the incentive rate that is applied to each performance measure. This will determine the level or reward or penalty that will apply for a particular service level outcome. In the sections below we discuss the basis for the incentive rates proposed by Western Power for each performance measure.

4.4.3.1 SAIDI and SAIFI

Western Power has proposed incentive rates for SAIDI and SAIFI based on its assessment of the value of customer reliability (VCR) as perceived on average by the users of its network. VCR is a measure of the value that customers place on improvements in supply reliability and is expressed in $/kWh. Western Power's assessment of the VCR for its network users is founded on research undertaken by Charles River Associates (CRA) for Vencorp in 2007, where CRA determined the VCR for four different user segments, residential, commercial, industrial and agricultural. For its analysis, Western Power has updated the CRA values to 2011-12 dollars.

[17] Except for the capex it plans to reduce the number of long duration interruptions. See Footnote 12.

The analysis used by Western Power to convert these VCR values to useable incentive rates is as follows.

- It has assumed total annual electricity sales to users connected to the distribution network, spread across all four user segments to be 14,090 GWh. The basis for this assumption is not clear; it does not correspond to the forecast sales for either 2010-11 (13,907 GWh) or 2011-12 (14,421 GWh) provided in Table 24 of the AA3 access arrangement information. However it is within the range of these two values and we do not see any need for adjustment.

- It has apportioned these sales across the four network feeder types, based on its sales records. This has allowed it to estimate the average expected energy not supplied for one SAIDI minute for each of the four feeder types. It also determined the average outage duration for each SAIFI interruption[18] and, from this, estimated the average expected energy not supplied as a result of a full SAIFI interruption.

- It has further apportioned the sales on each feeder type across the four different customer segments. This has allowed it to estimate the average value placed by users on each feeder type on energy not supplied.

A further step is to apportion the value of energy not supplied between SAIDI and SAIFI. Western Power has used the standard ratios used by the AER in its DSTPIS. This is shown in Table 4.18.

Table 4.18: Weightings for SAIDI and SAIFI

Feeder Type	Ratio of SAIDI to SAIFI
CBD	1.13
Urban	0.97
Rural Short	0.92
Rural Long	0.92

Source: Western Power and AER

The ratios shown in Table 4.18 are derived from an earlier willingness to pay study undertaken in 2002 by KPMG for the Essential Services Commission of South Australia. This study showed that commercial users were particularly concerned about SAIDI – if a supply interruption occurred these users wanted it to be as short as possible. Other user segments were less concerned about duration and more concerned about the number of interruptions – once an interruption occurred these user segments were more able to adapt and the length of the interruption became less important. The high ratio of SAIDI to SAIFI for the CBD feeder type reflects the higher proportion of commercial customers connected to CBD feeders.

The incentive rates determined by Western Power were the weighted average value of energy not supplied based on the customer profile for each feeder type and allocated across SAIDI and SAIFI in the ratios shown in Table 4.18.

We think the approach taken by Western Power to determine the SAIDI and SAIFI incentive rates is robust and the basis of the analysis mirrors the approach taken by the AER in DSTPIS. However there is a key difference. While Western Power has calculated the incentive rate for each network type based its own user profile, clause 3.2.2(b) of DSTPIS specifies the incentive rates that the AER uses for the networks it regulates. Had the AER incentive rates been applied to the Western Power network, the CBD incentive rate would have been higher, but the incentive rates for the other three network types would have been lower. Across the whole network the incentive rates calculated using the STIPS approach are generally lower than those proposed by Western Power.

[18] This was the ratio target SAIDI to target SAIFI. See Section 4.1.1.3.

As discussed in Section 4.3, we think the proposed AA3 SAIDI and SAIFI targets represent lower service levels than Western Power is currently providing. This implies that the probability of it exceeding its proposed targets is higher than 50%. This means that at the end of AA3 the net SSAM SAIDI and SAIFI payments are highly likely to provide a reward to Western Power. The higher incentive rates proposed by Western Power would increase the value of this reward.

A comparison of the SAIDI and SAIFI incentive rates, and the corresponding rates that we have calculated using the feeder type VCRs specified in DSTPIS is shown in Table 4.19.

Table 4.19: Comparison of Western Power and DSTPIS Incentive Rates ($, real 2011-12)4.19

		AA3 Incentive Rates	
		Western Power Proposal	**DSTPIS Methodology**
SAIDI ($ per minute)	CBD	68,346	71,619
	Urban	488,756	429,691
	Rural Short	199,256	183,063
	Rural Long	62,535	48,164
SAIFI ($ per interruption)	CBD	7,691,084	8,059,383
	Urban	43,177,909	37,959,971
	Rural Short	18,879,174	17,344,958
	Rural Long	8,779,766	6,762,106

Source: Western Power and AER.

4.4.3.2 Call Centre Performance

Western Power's proposed incentive rate for call centre performance is $60,190 for every 0.1% variation in performance.

This has been calculated as 0.04% of total distribution revenue for each 1% variation in performance. Western Power has used this approach because it is specified in clause 5.3.2(a) of DSTPIS. In order to establish an incentive rate, Western Power has taken the total distribution revenue to be the average annual distribution revenue for AA3, as calculated from its own revenue model. The Authority should adjust the incentive rate to reflect any changes to total distribution revenue resulting from its AA3 review. It is also open to the Authority to adjust the incentive rate annually, with the incentive rate for a given year being determined by the allowed revenue for that year. This is the approach favoured by the AER.

4.4.3.3 Transmission Circuit Availability

In its AA3 access arrangement Western Power states that it determined the incentive rate for transmission availability as follows:

> *We have calculated the incentive rate for the circuit availability performance measure by placing 0.5% of transmission revenue at risk through this measure. This is the same approach that was used in AA2 and the percentage is similar to the percentages used for circuit availability by other Australian electricity transmission companies.*
>
> *The AA3 incentive rate for circuit availability is higher than the AA2 incentive rate. This is because the AA3 transmission revenue is higher than the AA2 transmission revenue and the proportion of transmission revenue at risk for this performance measure is higher in AA3 than in AA2.*

The analysis used Western Power to calculate the incentive rate for transmission circuit availability is explained further in Table 4.20:

Table 4.20: Calculation of Incentive Rate for Transmission Circuit Availability

Average annual transmission revenue AA3 ($, real 2011-12)	$560,971,919
Revenue at risk (0.5%)	$2,804,859
Transmission circuit availability target	97.7%
Minimum transmission circuit availability	97.3%
Incentive rate (per 0.1% variance)	$701,215

Source: Western Power.

In the AA3 access arrangement information the incentive rate is given as $712,798. This difference is due to rounding. We agree with Western Power's approach except that, consistent with the discussion in Section 4.3.2.1, the target and expected minimum transmission circuit availability should be raised to 98.0% and 97.6% respectively. Alternatively, the expected minimum could be left at 97.3% and the incentive rate reduced to $400,694 per 0.1% variance. We also agree that placing 0.5% transmission revenue at risk for transmission circuit availability is generally consistent with the AER's past decisions.

Western Power's approach to determining the incentive rate has similarities to the approach specified by the AER in its transmission service target performance incentive scheme (TSTPIS)[19]. However there are some key differences:

- The percentage of total revenue at risk is termed a *weighting.* The TSTPIS provides more than one performance measure, each of which may be given a different weighting. The total revenue at risk under the scheme is determined by the sum of the different weightings, which is typically 1% of the total allowed transmission revenue in any year

- The maximum incentive or penalty that can be applied to any one performance measure is individually capped. Furthermore the scheme is symmetrical in that the maximum reward or penalty for each performance measure is the same. Under Western Power's proposal the maximum penalty is limited to 0.5% of transmission revenue whereas the maximum reward could potentially rise to 1%.

Under the TSTPIS approach the value of the performance measure that attracts the maximum reward is termed a "cap" and the value that attracts the maximum penalty is termed a "collar". Each performance measure included in the scheme will have a weighting, target, collar and cap. For a symmetrical scheme the variance between the target and the collar will be the same as the variance between the target and the cap. Hence two potential mechanisms to determining the reward and penalty for transmission circuit availability are shown in Table 4.21. Both approaches assume revenue at risk of $2,804,859 (as in Table 4.20) and our proposed target of 98.0%.

Table 4.21: Alternative Incentive Mechanisms for Transmission Circuit Availability

Collar	Target	Cap	Maximum Reward / Penalty ($, real 2011-12)	Incentive Rate ($, real 2011-12 per 0.1%)
97.6%	98.0%	98.4%	$2,804,859	$701,215
97.3%	98.0%	98.7%	$2,804,859	$400,694

Source: Western Power and GBA analysis.

4.4.4 Other Transmission Indicators

In section 4.2.3 we proposed that the following additional transmission indicators be included in the AA3 access arrangement as benchmark indicators.

- No of transmission interruption > 0.1 system minutes;

19 *Electricity Transmission Network Service Providers; Service Target Performance Incentive Scheme:* AER, March 2011.

- No of transmission interruptions > 1 system minutes; and
- Average interruption time.

If the Authority was so minded, these indicators could also be included in the SSAM, using an approach similar to that specified in the TSTPIS. In this section we suggest how this might be implemented. We note that the approach suggested in this section is only one of a range of possible approaches and the final scheme would depend on the behaviours that the Authority was seeking to drive through the implementation of the SSAM.

We suggest a total weight for the three measures of 0.4%. This would bring the total revenue at risk for the four transmission related measures to 0.9%. This is below the overall cap of 1%. However Western Power has included unplanned transmission interruptions in its SAIDI and SAIFI indicators, and further proposed that a proportion of the SAIDI and SAIFI rewards and penalties be allocated to (or taken from) transmission revenue[20]. The 0.1% margin makes provision for this.

The weighting assigned to average interruption duration could be 0.2%. We suggest a higher weighting be assigned to this indicator because interruption duration is likely to be particularly important to large users directly connected to the transmission network. In addition it is a measure where Western Power's ability to control the outcome is relatively high. Our suggested weighting for each interruption frequency measure is 0.1%

The targets for all measures could be the average 2008-11 performance shown in Table 4.15. We believe this is a fair reflection of the service level that Western Power is currently delivering on each measure.

While we think the targets should be based on Western Power's performance over three years we propose that, for the number of interruptions > 0.1 minute and the average interruption duration, the variance between the target and the collar/cap reflects Western Power's overall performance over the five year period 2006-11. We have calculated this variance as twice the standard deviation of Western Power's actual performance over this five year period[21]. For the number of interruptions > 1 system minute, we propose a cap of 0 and a collar of 4.

The parameters for this suggested model are summarised in Table 4.22.

Table 4.22: Possible SSAM Parameters

	No of Interruptions > 0.1 system minutes	No of Interruptions > 1 system minute	Average Interruption Duration (minutes)
Target	21	2	618
Cap	10	0	379
Collar	32	4	857
Weighting	0.1%	0.1%	0.2%
Revenue at risk	$560,972	$560,972	$1,121,944
Incentive rate (per unit/minute)	$50,997	$280,486	$4,694

Source: GBA.

20 See figure 34, p103 of the AA3 access arrangement information.

21 The variance between Western Power's proposed SSAM target and its proposed minimum service level performance standard was approximately two standard deviations.

5. ACTUAL AA2 CAPITAL EXPENDITURE

5.1 INTRODUCTION

As part of its review of the proposed AA3 access arrangement, the Authority must determine the value of the capital base at the beginning of AA3. This is to be determined using a roll forward approach, whereby efficient capex undertaken during AA2 will be added to the opening AA2 capital base.

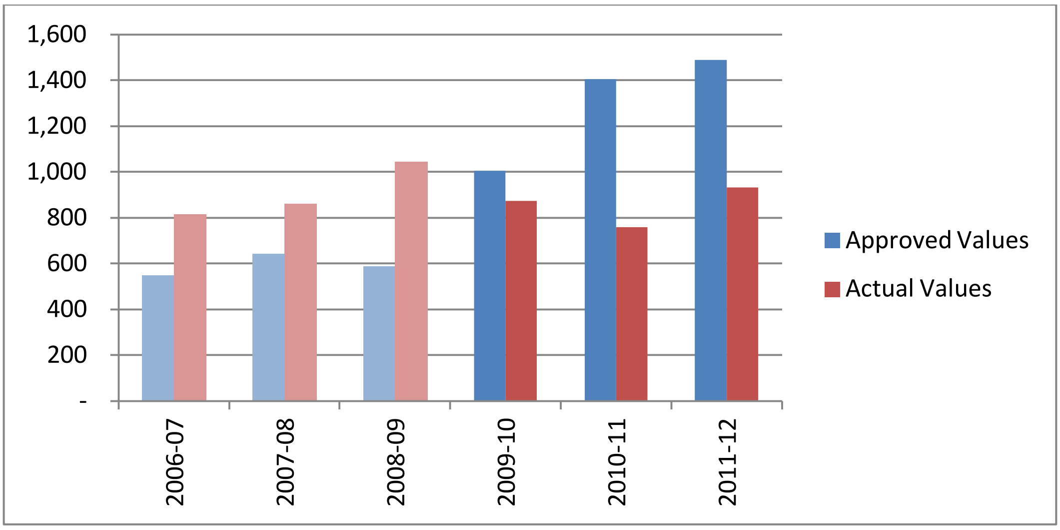
In accordance with Section 6.51 of the Access Code, capex can only be included in the capital base if it meets the requirements of the new facilities investment test (NFIT) in Section 6.52A of the Access Code. To this end, the terms of reference for our review included an assessment of Western Power's actual AA2 capex for compliance with NFIT requirements. This was done by reviewing a sample of the network capex projects and programs undertaken by Western Power over the period.

This section compares Western Power's actual capex during AA2 with the capex approved by the Authority in the AA2 access arrangement review. It also presents our conclusions on the level of compliance of Western Power's AA2 capex with the NFIT.

5.2 ACTUAL AND APPROVED EXPENDITURE

Figure 5.1 compares Western Power's total actual and expected[22] capex over both AA1 and AA2 with the capex approved by the Authority after the respective regulatory reviews. To enable a valid comparison, all expenditures have been converted to real 2011-12 dollars.

Figure 5.1: Actual and Approved Total Capex AA1 and AA2 ($ million, real 2011-12)



Source: Western Power and Economic Regulation Authority

It can be seen from Figure 5.1 that the total capex in AA2 was marginally lower than the actual capex in AA1 and was substantially lower than the approved AA2 amounts. In fact, the difference between the actual and approved values for AA2 is approximately 34%.

The main reason cited by Western Power for the lower level of capex in the AA2 period is the impact of the global financial crisis (GFC)[23], although it also indicated that deliverability was an issue in some areas. Western Power indicated that the GFC

22 In this section the expected capex in 2011-12 is the expected capex after Western Powers first quarter "F1" budget review. For brevity we have referred to this 2011-12 capex as "actual". However it is the latest forecast available and will be subject to confirmation at the end of the financial year.

23 The financial crisis of the late 2000s also referred to as the Global Recession, Global Financial Crisis or the Credit Crunch.

affected the availability of funding and its budget allocation from the Government was less than the AA2 capex approved by the Authority. Given this, Western Power had to request additional funding from the Department of Treasury. The uncertainty around the availability of funds, together with the write-down in the value of the capital base as a result of the Authority's AA2 final decision, led Western Power to review its capital works plan and a number of projects were put on hold pending the outcome of this review. Following the review a number of projects were deferred or cancelled.

Another reason given by Western Power for the reduced AA2 capex was favourable weather conditions, which presumably led to lower levels of remedial work due to a reduction in asset failures and outages.

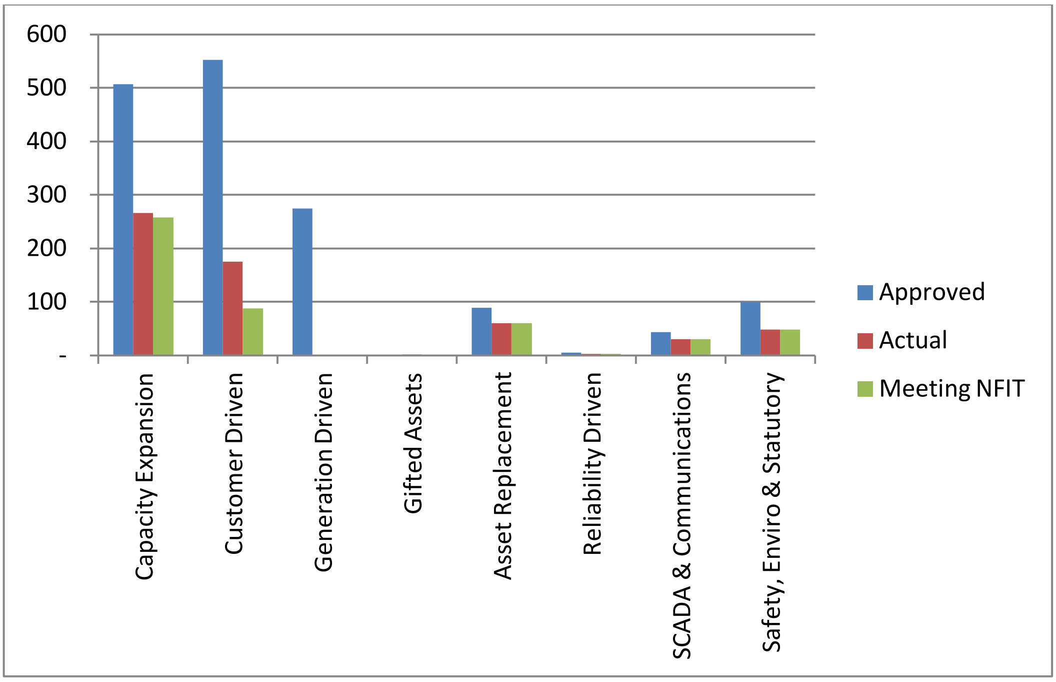
We note that growth related and customer driven capex is subject to the IAM in the AA2 access arrangement. In the event the Western Power does not spend the amount provided for in the access arrangement, the revenue provided to fund the unspent capex must be returned to customers in the following regulatory period, after adjustment for the time value of money. From the difference in the actual and approved capex for AA2, just over $ 1.3 billion, or around 80% of the total underspend, falls into the growth related and customer driven categories and will therefore be returned to customers through the IAM.

In order to improve our understanding of the reasons for the capex underspend over the AA2 period, we compared the actual and approved capex by asset category. This analysis is presented in the sections below.

5.2.1 Transmission Capital Expenditure

Actual AA2 capex for transmission related works is expected to be approximately 63% lower than the approved value. This amounts to under-expenditure of nearly $1 billion. Figure 5.2 disaggregates the actual and approved AA2 transmission capex into Western Power's standard regulatory categories.

Figure 5.2: Actual Versus Approved Transmission Capital Expenditure for period AA2 ($ million, real 2011-12)



Source: Western Power and Economic Regulation Authority
Note: Meeting NFIT is referring to Western Power's proposed NFIT amounts

As can be seen from Figure 5.2, capacity expansion, customer driven and generation driven projects have had the biggest under expenditure. It should be noted that generation driven capex has now been re-categorised and actual capex on projects in this category has been reallocated to the capacity expansion and customer driven expenditure categories. These categories account for slightly over 90% of the total under-expenditure or nearly $900 million.

5.2.1.1 Customer Driven Capex

Under-expenditure on customer driven projects amounts to 29% of the total capex approved for AA2 or 64%[24] of Western Power's total transmission related capex underspend. This was due to lower than expected demand for connection to the network and also to the impact of process and cost efficiencies achieved by Western Power. We acknowledge that customer driven capex is difficult to forecast as Western Power must react to customer applications. Its ability to forecast customer requirements in advance is limited.

5.2.1.2 Capacity Expansion Capex

As can be seen from Table 5.1[25], the project contributing the highest percentage variance from the approved capex was the Mid West Energy Project (MWEP). The reasons for this are well documented and not discussed further.

Table 5.1: Disaggregated Capacity Expansion Expenditure for period AA2 ($ million, real 2011-12)

Capacity Expansion Sub Category	Actual v Forecast ($)	Percentage of Total Absolute Variance
Expenditure deferred from AA1 to AA2	21.80	2.30%
Mid West Energy Project	(258.76)	27.29%
Expenditure Deferred Indefinitely	(240.96)	25.42%
Expenditure Deferred	(156.32)	16.49%
Expenditure Deferred due to Review of Transmission Planning Approach and Processes	(210.91)	22.25%
New Project Identified	26.16	2.76%
Wrong Expenditure Forecast Used at beginning of AA2	9.07	0.96%
Increased Need for Project to be Implemented	7.14	0.75%
Cost Estimation too Low	0.59	0.06%
Project Cancelled	(16.24)	1.71%
Other	0.13	0.01%
Total Variance	**(818.31)**	

Source: Western Power

Apart from the MWEP, the categories that had the biggest under expenditure were *Expenditure Deferred Indefinitely* and *Expenditure Deferred due to the Review of Transmission Planning Approach and Processes*. Under-expenditures were $240.96 million and $210.91 million respectively for these two categories.

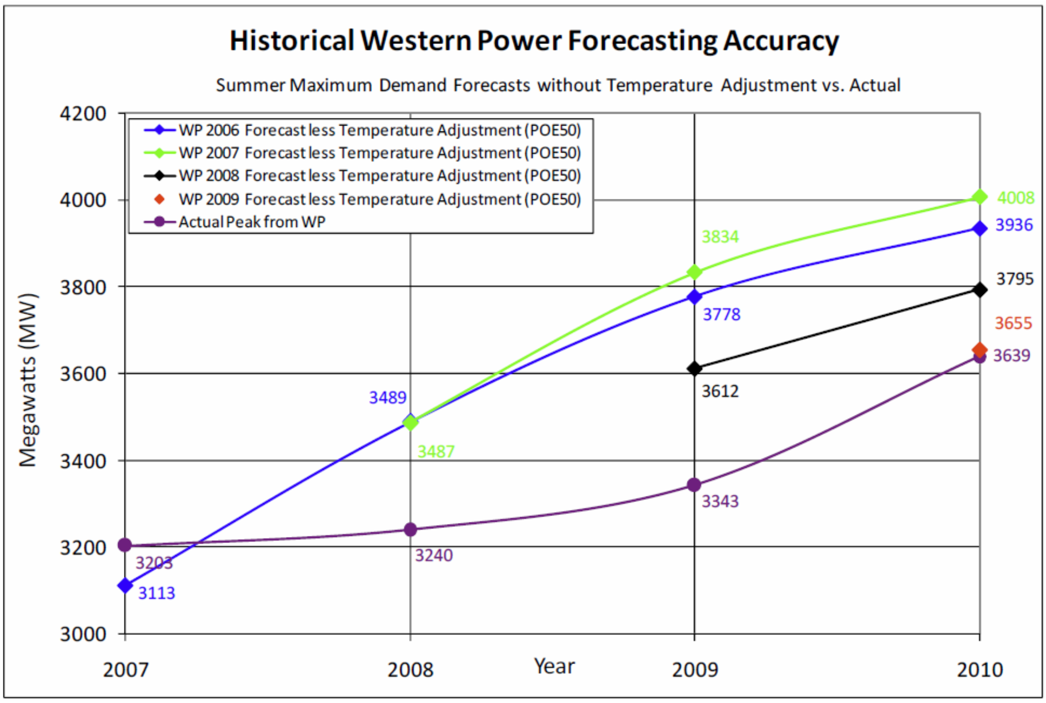
We considered the extent to which demand growth below the level anticipated at the time of the AA2 review could explain the level of underspend. Figure 5.3 compares Western Powers' forecast demands from the APR demand forecasts over the period 2007-10 with the actual demand over the period. The figure shows relatively low rates of growth in actual demand between 2007 and 2009 due to the GFC and an increase in demand in 2010 as Western Australia recovered from the GFC. Load forecasts on the other hand

24 Note that for the category of Customer Driven additional expenditure was incurred on programs/projects that were not foreseen at the start of AA2.

25 The figures shown in the Table 5.1 do not fully correlate with Figure 5.2. We note that in preparing Table 5.1 Western Power has reallocated the approved generation driven capex shown in Figure 5.2 to the capacity expansion and customer driven expenditure categories.

have trended downwards and the gap between actual and forecast demand has reduced, possibly indicating that forecasting is becoming more accurate.

Figure 5.3: Historical Western Power Forecasting Accuracy Rate



Source: Western Power

We understand that Western Power's 2009 system peak demand forecast was used as the basis for the final approved AA2 capex forecast. The forecast used to develop Western Power's transmission capex for the period were developed on the basis of a 10% probability of exceedence (10 POE), while the distribution capex used the 50% probability of exceedence (50 POE) forecast.

Table 14 of the Authority's final AA2 access arrangement decision forecast a total growth in demand of 8.2% between 2009 and 2011. This indicated a 10 POE forecast of about 3,700 MW in 2011 after making provision for demand variance[26]. In fact the actual demand, as reported by Western Power in its 2011 Annual Report, was 3,581 MW.

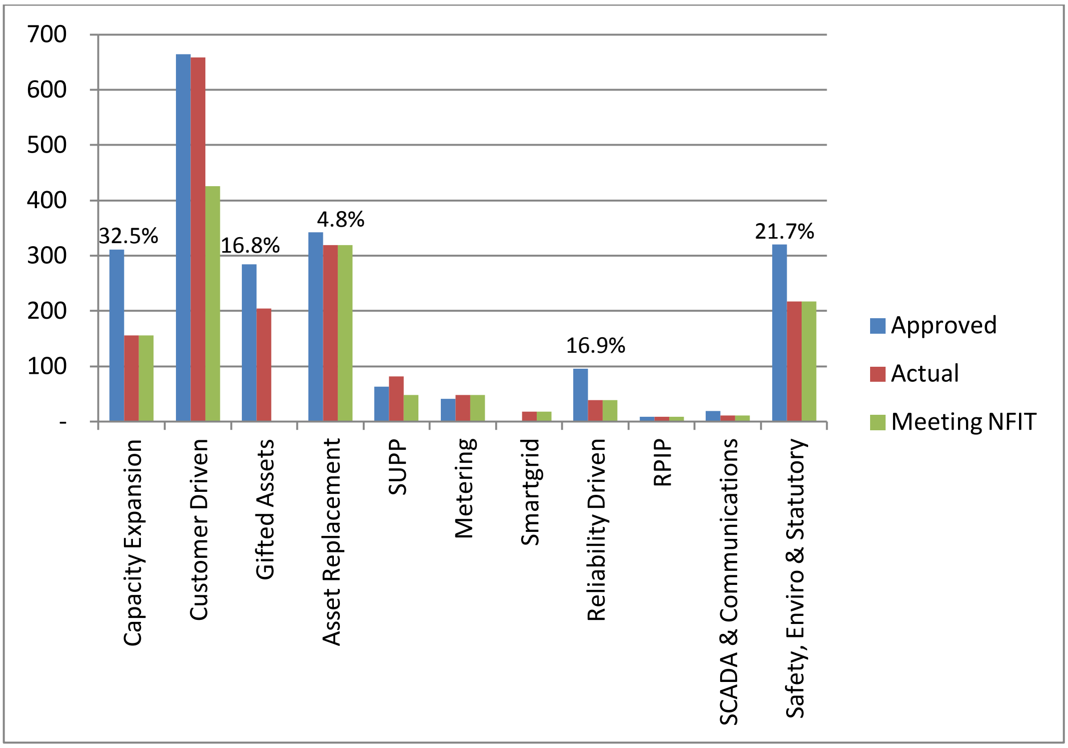
Hence the significant reduction in transmission capacity expansion capex has been achieved in spite of an actual demand comparable to that forecast at the time of the AA2 review.

5.2.2 Distribution Capital Expenditure

The expected AA2 capex for distribution related works is 18% lower than the expenditure approved in the AA2 review, a variance of nearly $390 million. Figure 5.4 compares the actual and approved capex on distribution works.

26 The actual peak demand in 2009 summer was 3,341 MW (Table 6.5). We derived the 8.1% growth by compounding the 2009-10 and 2010-11 growth rates shown in Table 14 of the Authority's AA2 final decision. This gives a forecast 2011 peak demand of 3,612 MW, which we have nominally increased to 3,700 MW to provide for the effect of environmental impacts on demand.

Figure 5.4: Actual Versus Approved Distribution Capital Expenditure for AA2 ($ million, real 2011-12)



Source: Western Power and Economic Regulation Authority
Note 1: Meeting NFIT is referring to the Western Power proposed NFIT amounts.
Note 2: The percentages at the top of some bars indicate the percentage variance from actual to approved expenditure values from the total absolute variance of distribution capex.

Figure 5.4 indicates that the value of gifted assets was lower than estimated at the time of AA2 approval. However, this does not affect the NFIT amount so is not considered further in this review.

The expenditure categories that have a material impact on the difference between the actual and approved expenditure are *Capacity Expansion* (32.5% of the total absolute variance), *Safety, Environment and Statutory* (21.7% of the total absolute variance) and *Reliability* (16.8% of the total absolute variance).

5.2.2.1 Capacity Expansion Expenditure

A total of 63% of Western Power's AA2 forecast distribution capacity expansion capex was for work on the high voltage network. Under expenditure in this area accounted for 57% of the absolute difference between actual and approved distribution related capex. Numerous projects affecting the high voltage distribution network were deferred or cancelled due to improved investment decision processes.

The next largest impact, accounting for 17% of the absolute difference between actual and approved distribution capex, was underspend on Perth CBD duct and pit systems. While $29.13 million was included in the approved AA2 capex for this work, it was deferred as a result of funding constraints and subsequent reprioritisation of the works program.

Western Power has also indicated that, as a result of improvements in processes relating to distribution planning, investment decision making and documentation requirements, a number of planned capacity expansion projects have been deferred or cancelled. This accounted for almost 16% of the absolute expenditure difference between actual and approved capex for distribution related works.

5.2.2.2 Safety, Environment and Statutory Expenditure

The most material expenditure areas having an impact on the under-expenditure for this subcategory (around 70% of the total under-expenditure) were projects relating to bushfire management and power quality compliance. Western Power provided numerous reasons for the expenditure variances, including operational efficiency improvements and reducing labour costs from bundling work across programs by geographic region.

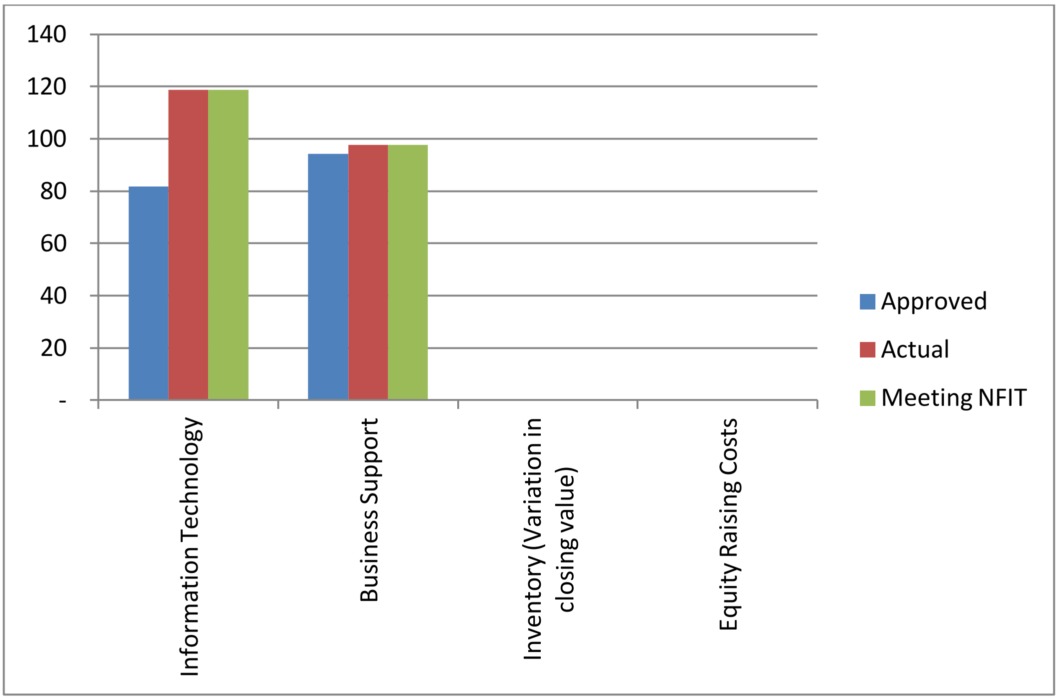
5.2.2.3 Reliability Driven Expenditure

For reliability driven expenditure, there was an under expenditure of 60% ($56.7 million) between the actual and approved expenditure for the AA2 period. Western Power stated that funding reliability projects became less critical as they were meeting and maintaining service standard benchmarks. As a result, the allocation was transferred to more critical work programs.

5.2.3 Other Capital Expenditure

In contrast to network capex, actual capex for information technology (IT) and business support expenditure was nearly 23% or just over $40 million higher than the AA2 approved amount. Figure 5.5 provides an insight into the actual capex for this expenditure category. The biggest contributor to this difference (approximately 92% of the total overspend), was IT expenditure.

Figure 5.5: Actual Versus Approved Other Capital Expenditure for period AA2 ($ million, real 2011-12)



Source: Western Power and Economic Regulation Authority
Note: Meeting NFIT is referring to the Western Power proposed NFIT amounts

More than 50% ($22.3 million) of this difference is due to the fact that IT infrastructure expenditure is now fully recovered from regulated revenues. Prior to 2010-11, Western Power shared its IT infrastructure with Synergy, Horizon Power and Verve Energy, which were disaggregated from Western Power in April 2006. Capex and opex relating to the disaggregated entities were recovered from these entities and those relating to Western Power were charged back to the regulated business through business unit charges. Western Power's sourcing model changed in 2010-11 and it no longer holds capital assets to provide IT infrastructure to the disaggregated entities.

The remaining major items impacting the actual capex overspend for IT over the AA2 period are listed below:

- $5 million capex on the meter data management system was brought forward from AA3 to 2011-12;
- There was $6.3 million additional capex on the mobile workforce solution and the enhanced planning and works management programs as the effort and cost to implement these programs was underestimated in the AA2 forecast;
- There was $1.2 million additional expenditure on the Ellipse upgrade project, which was endorsed through appropriate business case and change variations. The Ellipse upgrade project introduced efficiencies in human resource and payroll management, and established the foundation infrastructure that allowed transformation work on Western Power's asset and works management processes to proceed; and
- There was also a further $1 million additional expenditure on Western Power's mobile workforce solution to activate the wood pole inspection pilot project and allow the enhancement of a larger mobile program.

5.2.4 Conclusions

Western Power's total capex during AA2 is expected to be 34% ($1.3 billion) lower than the $3.9 billion approved by the Authority. The major areas of under-expenditure were network related, particularly capacity expansion and customer driven capex, on transmission and, to a lesser extent, distribution assets. However, non network IT capex was overspent.

Most of the under-expenditure was in the capacity expansion and customer driven capex categories. The funding allocated in the AA2 access arrangement to finance the under-expenditure in these categories will be returned to customers during AA3 through the IAM. However the IAM does not apply to non-growth driven capex and the funding provision for non-growth driven capex that was not utilised in AA2 will be retained by Western Power and not returned to customers.

Customer driven capex was significantly lower than the level forecast at the time of AA2 approval, indicating a reduced demand for network connection, particularly from larger customers. This capex is difficult to forecast.

Western Power further suggested that the GFC reduced the demand for electricity and much of the approved AA2 capex was therefore not necessary. However, our analysis indicates that the peak demand in 2010-11, the most recent year for which an actual peak demand is available, was comparable to that anticipated at the time the Authority issued its final decision on the AA2 access arrangement.

A major reason for the under-expenditure was that the Authority's AA2 final decision did not allow all Western Power's actual AA1 capex to be included in the opening capital base for AA2. As a result, Western Power put much of its planned capacity expansion expenditure on hold while it reviewed its network development planning processes. Subsequently, many planned projects have been deferred or cancelled. A further factor impacting the actual capex during AA2 has been funding constraints imposed by the Government. Western Power finances its capital works program from funding provided by the Western Australian Treasury, which we understand has required all state owned entities to restrain their capex programs as a response to the GFC. Western Power has not been immune to these pressures.

Notwithstanding this significant capex underspend, Western Power has met or exceeded 34 of the 38 (89%) AA2 access arrangement network service level benchmarks over the first two years of AA2. Hence, the capex under expenditure has not caused Western Power's service levels, on average, to fall below the service levels forecast at the time of AA2 approval. In fact the actual service levels have been significantly better than anticipated, since we understand that the AA2 service level benchmarks were set at a level where it was thought that there was only a 50% probability of each benchmark being exceeded.

We conclude that there was a significant level of inefficiency in Western Power's AA2 capex forecast, which was higher than it should have been. While Western Power's capex management, project forecasting and estimating processes have now improved, the Authority may wish to take a conservative approach in approving the AA3 capex. The Authority could decide that, given that any capacity expansion capex overspend that meets NFIT requirements can be recovered in AA4 through the investment adjustment mechanism, it is better for the approved capex to be a little lower, rather than substantially higher, than the amount eventually required. Customers will then not be asked to pay more during AA3 than needed to fund the actual capex requirement, and the incentive on Western Power to deliver only an efficient level of capex is likely to be greater. This is because the actual AA3 capex is likely to be subject to more intense ex-post scrutiny at the time of the AA4 review if it is higher than the Authority's approved amount.

5.3 NEW FACILTIES INVESTMENT TEST

5.3.1 Background

New facilities investment is defined in the Access Code as the capital cost incurred in developing, constructing and acquiring a new facility, where "new facility" means any capital asset developed, constructed or acquired to enable Western Power to provide regulated network services. In effect it covers all regulated capex on transmission and distribution network assets.

Such investment may only be added to the capital base in accordance with the requirements of clause 6.51A of the Access Code. This requires that, unless the assets are gifted to Western Power or funded through a capital contribution, the investment must meet the requirements of the NFIT.

The NFIT requirements are set out in Section 6.52 of the Access Code. In order to meet the requirements of the NFIT an investment must pass an *efficiency test* as set out in clause 6.52(a) of the Access Code as well as one or more of the following tests:

- an *incremental revenue test* as set out in clause 6.52(b)(i)A of the Access Code; or
- a *net benefits test* as set out in clause 6.52(b)(ii) of the Access Code; or
- a *safety or reliability test* as set out in clause 6.52(b)(iii) of the Access Code[27].

These tests are described in more detail in the following sections.

5.3.1.1 Efficiency Test

The efficiency test requires that the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs having regard to:

- whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and
- whether the lowest sustainable cost of providing the regulated network services forecast to be sold over a reasonable period may require the installation of a new facility with capacity to meet the forecast sales.

[27] The test in clause 6.52(b)(iii) of the Code may include an assessment of safety or the ability of the network to provide contracted covered services as alternatives to reliability. However, for convenience, this test is sometimes referred to as the *reliability test* throughout this report.

5.3.1.2 Incremental Revenue Test

A new facility investment will pass the incremental revenue test if the anticipated incremental revenue derived from the new facility is higher than the cost of the facility. The test is used to assess an investment in an augmentation of the shared network that is constructed specifically to allow a new user to connect to the network. For the purposes of this test, incremental revenue is defined in the Access Code as the net present value of the anticipated additional revenues to Western Power from the new customer less the net present value of the costs associated with servicing the new facility (principally maintenance costs).

The Access Code includes a provision for an access arrangement to include a modified test that would be applied in place of the incremental revenue test where the proposed new facilities investment is below a prescribed test application threshold. Western Power's AA2 access arrangement does not include such a test.

Where the required new facilities investment to permit a new user to connect is greater than the anticipated incremental revenue, Western Power can request the user to pay a capital contribution to make up the difference. It currently uses a standard capital contribution spreadsheet model to calculate the amount of any contribution required. The model estimates the net present value of forecast revenues and maintenance costs over a project life (normally assumed to be 15 years) in order to determine the value of the investment that the new connection will support.

The incremental revenue test is not applied to assets installed on the customer's side of the connection point as these assets do not form part of the regulated network. It is also not applied to distribution infrastructure for the reticulation of new subdivisions or to other works covered by Appendix 8 of the Access Code. The user or developer must pay the full cost of these new assets and, in the case of subdivisions where the assets will eventually from part of the shared network, they must be gifted to Western Power after completion.

As capital contributions are not subject to the NFIT, they are outside the scope of this review. However, in assessing whether a particular new facilities investment complies with the requirements of the NFIT we have assessed, and where appropriate commented on, the extent to which the investment has been funded through a capital contribution. This assessment is necessary to determine the value of the investment to which an incremental revenue test must be applied.

5.3.1.3 Net Benefits Test

A new facilities investment will pass the net benefits test if the new facility provides a net benefit over a reasonable period of time that justifies the approval of higher reference tariffs. The Access Code defines a net benefit as applying to those who generate, transport and consume electricity (which includes both users and also Western Power as the network operator), and it also requires that it be measured in present value terms to the extent that it is possible to do so.

The net benefits test is used for growth driven investments that cannot be attributed to a single network user. It is a standard test applied in the industry and recognises that higher costs (and therefore tariffs) in the short term may be appropriate if incurring these short term costs minimises total stakeholder costs when measured over a longer period. The test might be applied, for example, in a situation where a network extension was necessary to enable the connection of new low cost generation. Such an extension would pass the net benefits tests if the net present value of the savings in generation costs was higher than the net present value of the capital and ongoing maintenance costs of the extension that was needed to connect the new generator.

5.3.1.4 Safety or Reliability Test

A new facilities investment will pass the safety or reliability test if the new facility is necessary to maintain the safety or reliability of the SWIN or its ability to provide contracted covered services. We are unsure of the intent of the wording …*or its ability to provide contracted covered services* and assume that the word "contracted" implies maintenance of service to existing customers. Hence, we think the reliability test was primarily intended to be applied to non-growth driven new facilities investment and for this review we have made this assumption.

Hence a growth driven new facilities investment will not meet the requirements of the NFIT simply because Western Power would be unable to connect new customers if nothing was done. For our assessment such an investment would need to meet the requirements of either the incremental revenue or net benefits test depending on whether or not the investment was for the benefit of a single new customer.

We further note that a safety or reliability investment must also meet the requirements of the efficiency limb of the NFIT. This prevents inefficient investment that could arise from "gold plating" or the installation of excess capacity.

5.3.2 NFIT Assessment of Individual Projects and Programs for AA2 Capital Expenditure

The objective of this review was to assess whether the actual and forecast capex for the AA2 period meets the NFIT requirements as set out in Section 6.52 of the Access Code. This was done by reviewing a sample of 19 capital projects undertaken during AA2 to assess whether these individually meet the NFIT requirements. Our review of whether or not a project met the efficiency test component of the NFIT included an assessment of:

- the extent to which Western Power applied its expenditure management governance processes in the development, approval and implementation of the project or program;
- the justification for any positive or negative variance between the estimated cost at the time of project or program approval and the final project or program cost;
- the justification for project or program implementation schedule changes; and
- the scope of the forecast project compared to the scope at the time of project approval.

This approach was predicated on the assumption that if a capex project or program was implemented in accordance with Western Power's expenditure governance procedures then it can be assumed that implementation was efficient and wasteful expenditure did not occur.

We also considered the extent to which the project satisfies the second limb of the NFIT test. This included an examination of the basis on which this limb was satisfied and whether this assessment was made at the time the project was approved in a manner that is consistent with Western Power's governance procedures;

The detailed reviews of each project or program assessed are documented in Appendix A. Issues relating to individual projects and programs that we have reviewed are discussed below.

5.3.2.1 Distribution Pole Replacement

The program is discussed in Appendix A1. The number of wood poles expected to be replaced during AA2 is almost 38,000, 13% more than the 33,500 forecast at the time of the AA2 review. The average unit cost of these replacements is expected to be [redacted] (real 2011-12), [redacted] higher than forecast during the AA2 review. However average unit costs of wood pole replacement have increased from [redacted] in 2010-11 to [redacted] in 2011-12, an increase of 17%. No accelerated depreciation of the capital base has been applied to poles replaced under this program.

Given the extreme risks to Western Power of unassisted pole failures, Western Power's decision to increase the number of pole replacements beyond the level anticipated during the AA2 review is reasonable. Furthermore, the [redacted] increase in the average unit cost of pole replacements during AA2 above the level accepted by the Authority during the AA2 review does not seem excessive. However, the 17% increase in the unit cost of pole replacements between 2010-11 and 2011-12 is very high and has not, in our view, been fully justified by Western Power. Nevertheless, we acknowledge that Western Power has been under much pressure to increase its rate of wood pole replacement and this can make it difficult to tightly control costs. On balance, we think all AA2 capex on pole replacements meets NFIT requirements.

One reason given for the 17% average unit cost increase in 2011-12 is an increase in the ratio of planned to unplanned replacements. It is not clear to us why capex on unplanned pole replacements should be lower than on planned replacements, apart from the fact that unplanned replacements are likely to be undertaken by in-house staff with lower labour costs. Western Power appears to take the view that there is a fault response component to an unplanned pole replacement and this component should be treated as opex. This is reasonable. However, the basis for determining that the proportion of unplanned pole replacement cost that is treated as opex should be 55% is not clear. It may be more reasonable to capitalise a fixed amount, based on the average cost of a planned pole replacement, and then treat the balance of the unplanned pole replacement cost as opex. In particular, as the materials cost is likely to be little different for a planned or unplanned pole replacement, is unclear why as much as 55% of the materials cost of unplanned pole replacements should be treated as opex.

We also have concerns, which we have not been able to fully resolve, regarding the capital base accounting treatment of replaced wood poles. Table 72 of the AA3 access arrangement information indicates that no accelerated depreciation is been applied to replaced poles, (except to poles removed as part of the State Underground Power Program). We think it is reasonable to assume that poles replaced as a result of condition assessments or unassisted pole failures would, on average, have reached the end of their economic life. However this would not necessarily be true for poles replaced after an assisted pole failure, such as after being hit by a car.

Our concern is whether pole assets are individually identified in the capital base or whether they are aggregated by asset category with each pole, in effect, assigned an assumed average life. Western Power has stated that, for the asset valuation undertaken at the commencement of AA1 the average remaining life of distribution wood poles was assessed to be 14.5 years. If all poles in existence at that time were assumed in the register to have this life, then all poles that were replaced as part of this program would still have a positive asset value at the time of replacement and should therefore have been be subject to accelerated depreciation on replacement. If wood pole lives are averaged in the capital base and no accelerated depreciation is applied, the value of the capital base will be overstated and customers will be paying Western Power a return on assets that are no longer in service.

5.3.2.2 *Strategic Program of Works*

This program is discussed in Appendix A2. The strategic program of works (SPOW) was established to manage a portfolio IT projects to enhance Western Power's capabilities and business processes in areas including asset and work management, customer management, finance, human resources and logistics. These objectives were to be achieved through the replacement of outdated legacy IT applications and automating processes currently done manually.

At the time of the AA2 review, the total forecast SPOW capex in AA2 was approximately $68 million. Western Power now expects to spend $82.7 million on the program, an overrun of $14.7 million or almost 22%. Western Power considers that all actual AA2 SPOW capex satisfies NFIT requirements.

We reviewed the two largest sub-projects within this program, the integrated solution for asset management (ISAM) and the mobile workforce solution (MWS). However, together these projects account for only for only 44% of the expected $82.7 million AA2 capex.

We consider that all capex incurred during AA2 on the ISAM and the second phase of the MWS satisfies NFIT requirements. However, it appears that much of the cost overrun on the first phase of the MWS arose through process inefficiencies. We think insufficient time was spent researching and evaluating alternative approaches to addressing the need, possibly because the schedule did not allow adequate time for project development. We also understand that the initially approved implementation cost of this project was allowed to overrun by $1 million, or almost 30%, without proper approval. We conclude that the initial project cost estimate satisfies NFIT requirements but have seen no evidence to suggest that the cost variations would have been necessary had the initial project development been more comprehensive. We are therefore not satisfied that the $5.7 million cost overrun on this phase meets NFIT requirements. We suspect that this sub-project may have been rushed so that Western Power was seen to be responding to concerns raised by stakeholders over its implementation of the wood pole management program.

In its AA3 access arrangement information, Western Power indicated that it considered the full AA2 capex for this program satisfied NFIT requirements and included the full amount in the AA3 opening capital base. However the business case that it subsequently provided on the meter data management (MDM) subproject did not support its estimated AA2 subproject capex of $5 million. We are therefore unable to form an opinion on the extent that capex we have not reviewed might satisfy NFIT requirements.

5.3.2.3 Power Quality Compliance Program

This capex program is discussed in Appendix A6. The expected actual capex for AA2 is $16.2 million, compared to a forecast of approximately $35 million at the time of the AA2 review. This difference appears to be largely the result of forecasting errors that were not identified until a 2010 review.

We consider the program fully meets NFIT requirements. While only the actual capex will be included in the opening AA3 capital base, funding during AA2 for the full forecast capex was provided for in the AA2 access arrangement. As this program is not subject to the IAM, there is no mechanism in the regulatory arrangements for the excess funding to be returned to customers.

5.3.2.4 Second Picton-Busselton 132 kV Line

This project is discussed in Appendix A8. Western Power's approved AA2 forecast included a provision of approximately $25 million for the construction of a second 132 kV line between Picton and Busselton, primarily to relieve a potential under voltage condition at Busselton. Following the 2010 transmission review the second line has been deferred indefinitely, with construction not now expected until about 2019-20. Western Power is now planning to install capacitor banks at Busselton to provide voltage support. However Western Power still considers that $102,000 of expenditure incurred on the second line meets NFIT requirements. This expenditure included internal labour, indirect cost allocations and flora, fauna and dieback assessments.

Our analysis indicates that, given the information available to Western Power at the time, the second Picton-Busselton line included in the original AA2 capex forecast was unlikely to have been the most cost effective project to mitigate the potential under-voltage issue at Busselton. Now that the project has been deferred, we consider that Western Power's actual expenditure on the project does not meet NFIT requirements and should not be included in the AA3 opening capital base.

5.3.2.5 Distribution Capacity Expansion

Three distribution capacity expansion projects were reviewed and these are discussed in Appendices A17, A18 and A19. For two projects, the actual expenditure was substantially higher than that of the original AA2 forecast. However in both cases the AA2 forecast was prepared before the projects' requirements had been assessed in detail and formal scopes of work developed. In the event, the actual work required for both projects was greater than had been anticipated at the time both forecasts were prepared.

We consider that the actual AA2 capex for all three projects satisfies NFIT requirements.

5.3.2.6 Transmission Line Relocations

This program is discussed in Appendix A11. Transmission line relocation requests are initiated by external parties who are expected to cover the full cost of the relocation through payment of capital contributions. However, Western Power considers that $1.9 million of actual AA2 expenditure meets NFIT requirements. It explained that:

> *As the transmission line relocations suite of projects are treated as a program, there are individual projects which are at each phase and gate of the works program governance framework at any given time. The amount of $1.902 million noted as meeting NFIT in a previous response represents the amount which has not yet been recovered through capital contributions where the reconciliation process is not yet complete. It is Western Power's intention to recover these costs in full from the customers concerned.*

The NFIT amount for this project is Western Power's estimate of the outstanding capital contributions at the end of AA2. As Western Power's policy is to fully recover the costs of transmission line relocations through capital contributions, the NFIT amount should be recovered during AA3 and returned to customers through the IAM. In the event that a line relocation does not proceed, or capital contributions are unable to be recovered from the party requesting the relocation for any reason, any capex incurred by Western Power will remain in the capital base and be funded by customers.

5.3.2.7 Meters and Associated Equipment

This program is discussed in Appendix A5. Western Power expects to spend $43.3 million during AA2 on meter installation and replacement, 9% more than the original AA2 forecast.

We consider that, in principle, the program satisfies NFIT requirements. However, the F1 forecast for 2011-12 does not appear to take into account the purchase of surplus meters in 2010-11 and thus could be high. To this extent the actual A2 capex meeting NFIT requirements could be overstated.

This situation appears to have arisen primarily because Western Power provided for an expected increase in the demand for replacement meters on the premises of small use consumers installing photovoltaic arrays in parallel with the network. However this expected increase in demand did not materialise after the government introduced changes to the feed in tariff scheme.

Western Power does not apply accelerated depreciation to meters that are removed from service and replaced. This means that the value of the capital base is over stated. The reason for this accounting approach is to ensure that Western Power fully recovers the investment cost of assets that are removed from service before being fully depreciated. However, it also means that consumers are required to pay a return on the value of assets that are no longer in service.

5.3.2.8 State Underground Power Program

This program is discussed in Appendix A10. Only Western Power's contribution to this program is subject to the NFIT. This contribution is 25% of total costs, which include both capex and associated opex. However, as external contributions are first netted off against opex, Western Power's contribution will appear to be greater than 25% of the total capex. Given this, and the inconsistencies in the information Western Power provided to us, we were unable to determine an exact NFIT amount but expect it to be of the order of $21 million.

5.3.3 Environmental and Planning Capex

Western Power's expected AA2 capex includes a provision of $4.3 million in 2011-12 that is categorised *environmental* and *planning,* which does not relate directly to the construction of a physical asset that is committed for construction. These categories of expenditure are discussed in Section 7.2.5. However, we do not consider that this expenditure meets NFIT requirements since we do not see how an intangible or non-physical asset can meet the requirements of the incremental revenue test, the net benefits test or the safety or reliability test.

5.3.4 Conclusions

The documentation provided by Western Power for each individual project or program review varied in the level of detail and the quality and quantity of information provided. In some cases it was difficult to assess the level of rigour applied by Western Power in developing the scope the projects or programs and in particular the priority given to developing and evaluating different project alternatives. Apart from reservations about the extent that different alternatives were developed and evaluated in the project development phase, we consider that the implementation of Western Power's expenditure governance processes during AA2 was generally good. Incremental improvements to these processes were made over the period and it follows that management of capex improved as a result.

We identified one instance, the phase 1 MWS component of the SPOW, where we consider that inadequate implementation of governance processes had a significant impact on the project outcome. This $3.2 million project is now expected to have a final cost of $8.9 million. We consider that much of this cost overrun would have been avoided had a range of implementation options been properly researched and discussed in the business case. Western Power also allowed the project cost to overrun by at least $1 million without proper internal approval processes being undertaken.

We make the following specific observations in respect of our review of the recoverable amount of Western Power's AA2 capex that satisfies NFIT requirements.

- We consider that only the initial cost estimate of $3.2 million for the phase 1 MWS project satisfies NFIT requirements as we are not satisfied that the $5.7 million cost overrun on this phase satisfies the NFIT efficiency test;

- We are unable to form a view on the extent to which the $46.7 million component of SPOW capex that we did not review meets NFIT requirements. In its AA3 access arrangement information, Western Power considered that all actual capex on this program was NFIT compliant. However the business case that it subsequently provided on the meter data management (MDM) subproject did not support its estimated AA2 subproject capex;

- We do not consider that any capex associated with the Picton-Busselton line meets NFIT requirements;

- Western Power has confirmed that all transmission line relocation capex should be recovered from the party requesting the relocation and that its proposed NFIT amount at the end of AA2 represents its estimate of outstanding contributions still to be recovered from customers at that time. . In the event that a line relocation does not proceed, or capital contributions are unable to be recovered from the party requesting the relocation for any reason, capex incurred by Western Power will remain in the capital base and be funded by customers;

- We do not consider that the $4.5 million capex expected to spent in 2011-12 and classified as planning or environmental meets NFIT requirements;

- Western Power's F1 expected metering installation and replacement expenditure in 2011-12 may be high in that it does not appear to have taken into account the fact that meter purchases in 2010-11 were significantly higher than the actual requirement. To this extent we think the NFIT compliant amount for this line item might have been over stated.

- We were unable to determine the exact amount of Western Power's contribution to the SUPP that meets NFIT requirements but expect it to be approximately $21 million.

We note that the proposed NFIT compliant amount in the AA3 access arrangement information was Western Power's estimate of its actual 2011-12 capex at the time it prepared the document. This estimate has now been superseded by the F1 forecast and will be updated quarterly as the year progresses. The proposed NFIT compliant amount also includes capital contributions for expenditure that is expected to have been incurred before the end of AA2 but where the contribution is not expected to have actually been received by Western Power. We consider that, where programs or projects are expected to be funded by capital contributions any expenditure by Western over and above the contribution amount should not be passed on to consumers.

Two projects we reviewed, distribution wood pole replacement and meter replacement, involve the routine removal from service of assets that may not be fully depreciated in Western Power's capital base. In neither case has Western Power provided for accelerated depreciation in its assessment of the NFIT compliant amount.

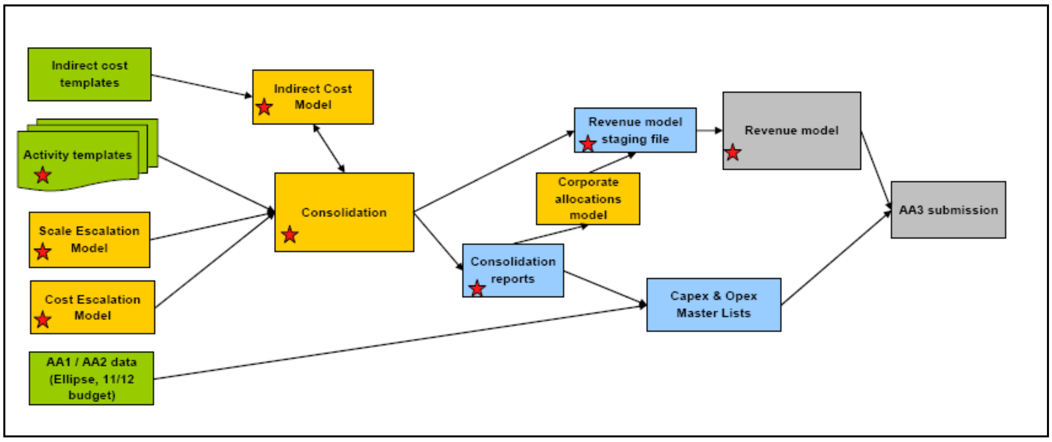
6. FORECAST METHODOLOGY

6.1 COST ESTIMATION AND ESTIMATING RISK

Western Power has continued to improve its cost estimation processes in line with the recommendations of the Tellis Chase report[28]. This report was critical of the accuracy of Western Power's cost estimates using the processes in place during AA1. It provided ten recommendations for improvement in the way Western Power estimates the cost of programs and projects. These improvements have generally been implemented and have been reflected in an improvement in the accuracy of cost estimates made during AA2. They have also resulted in the addition of over 150 new building block estimates that have been used in estimating AA3 expenditure.

The approach to developing the cost estimates used in the AA3 expenditure forecasts is summarised in Figure 6.1. Western Power has established a dedicated estimating centre for preparing and managing estimates.

Figure 6.1: Cost Estimation Process



Source: Western Power

The key processes used by Western Power in preparing its AA3 cost estimates were:

- collecting cost estimates/forecasts for individual projects and programs;
- consolidating these into direct cost forecasts;
- calculating and applying indirect costs to the direct costs;
- applying cost escalation; and
- reporting totals.

In preparing its cost estimates Western Power utilised the following three estimating systems:

- *Success Estimator* – This is a commercial, off-the-shelf system used for complex distribution and transmission estimates. It is independently used by different areas of the business to create a series of sub-estimates that are consolidated to create the final estimate for a project. Individual cost databases are maintained by each individual area such as SCADA, communications, protection, and substations. Once the sub-estimates prepared by different business areas are consolidated, the estimating centre updates the schedule of rates from a rates

28 In 2007, Western Power engaged Tellis Chase to compare its approach to cost estimation with best business practice. The Tellis Chase final report was issued in September 2007,

database. The estimating centre receives updates to rates via individual extracts from Ellipse.

- *Distribution Quotation Management System (DQM)* – This is an in-house system predominately used for volumetric or less complicated distribution work, including customer funded and capacity expansion projects. DQM interfaces with Ellipse to extract rates for labour and materials used in compatible units (CUs), which are utilised to generate estimates and customer quotes.

- *Building Block Estimates* – This is a spreadsheet based system predominately used for estimates produced for approval at gate 1 of Western Power's new seven gate governance process. Rates used in this system are obtained from past projects and information from the estimating centre. Very high level modules are entered with rolled up costs.

Sinclair Knight Merz (SKM) has carried out benchmarking on Western Power's estimates of the cost of large transmission projects and found them to be generally within a 20% bandwidth of actual costs and comparable to estimated costs for similar projects in the eastern states.

The processes that Western Power has described in preparing its estimates appear to be soundly based and in keeping with good electricity industry practice. We have not attempted to audit any of the processes so have relied on Western power's documented processes and presentations on their estimating approach. We note that in preparing its AA3 expenditure forecast, Western Power has relied heavily on historical costs. Any efficiencies (or inefficiencies) in historical costs will be reflected in the overall AA3 forecasts.

Given our general satisfaction with the cost estimation methodology, for this review we have generally accepted that Western Power's forecast capex cost estimates as reasonable and largely focused our assessments of the AA3 transmission and distribution capex forecasts in Sections 7, 8 and 9 on the need for, and timeliness of, the different projects and programs proposed by Western Power.

6.2 COST ALLOCATION AND OVERHEADS

In preparing the AA3 forecasts Western Power has advised that all overhead costs have been calculated and applied in accordance with Western Power's cost and revenue application method (CRAM). Under CRAM, Western Power broadly categorises costs into one of three categories:

- *Direct costs*. The underlying transaction can be directly identified and attributed to a business service.

- *Indirect costs*. These do not relate to a specific project, program or service but are more generally concerned with the development and implementation of the AWP. These costs are allocated using an indirect cost allocation method. The allocation of costs across the AWP attributes costs to both regulated and unregulated services.

- *Corporate costs*. These costs relate to a business support service or other cost category. They are allocated using a method that most appropriately reflects the cost's causal correlation with the underlying transaction such as being based on full time staff equivalents (FTE), property, plant and equipment and intangibles (PPE) and land and buildings (L&B) are the common allocation methods applied. The indirect costs incurred in network and operational areas (such as training and travel costs and non-timesheet labour) cannot be directly attributed to specific services within the AWP. These costs are identified in an 'indirect cost pool' and allocated across the AWP using an indirect cost allocation method.

The indirect cost allocation method allocates the costs to from an 'indirect cost pool' to the AWP through two steps:

- The first step involves allocating the labour related indirect costs using a 'labour time' recovery rate for every internal labour hour charged to a specific service.

- The second step allocates the remaining non-labour related indirect costs proportionally across the AWP based on the direct costs incurred by each specific service. The proportional rate at which this occurs (the indirect cost recovery rate) is calculated annually during the budget process and is monitored on a monthly basis to review actual recovery against the works program. Quarterly adjustments are made if the actual recovery of costs through the indirect cost allocation method varies from the actual indirect overheads incurred.

The indirect cost allocation method does not differentiate in the method of allocation across capex and opex. It capitalises the indirect costs that are allocated to capital projects, while the indirect costs allocated to the maintenance program are treated as opex.

Western Power's approach to indirect cost allocations appears to be broadly consistent with approaches used by other utilities within Australia. Western Power has described the process for the formulation of its AA3 estimated expenditure and as part of that process it has described a discrete process step for the allocation of indirect costs to direct costs in a manner that should prevent any double counting of costs between capex and opex.

In its AA3 expenditure forecasts, Western Power has provided capex and opex expenditure line items inclusive of indirect cost allocations. Corporate costs were shown separately. We asked Western Power to separate out and disaggregate is indirect cost allocations for this review. These are discussed in Section 9.4 (capex) and Section 10.9 (opex). Western Power's forecast corporate capex forecast is discussed in Sections 9.1-9.3 and its corporate opex forecast is discussed in Section 10.8.

6.3 CAPITALISATION

At the beginning of each regulatory period Western Power's opening capital base is reset. Clause 6.48 of the Access Code permits the reset to be either by means of an asset revaluation or by rolling forward the opening capital base for the previous regulatory period using the actual capex. In determining its proposed opening AA3 capital base, Western Power has adopted the roll forward approach and has rolled forward the approved opening AA2 capital base on the basis of the actual AA2 capex. In resetting the AA3 opening capital base, the Authority requires this actual capex to be subject to an ex-post review for compliance with NFIT requirements. We have assisted the Authority with this review and our advice is included in Section 5 of this report.

In undertaking the roll forward analysis, it is assumed that capex is added to the capital base in the year the expenditure is incurred rather than when an asset is commissioned; hence no finance during construction component is included in either the actual or forecast capex.

The opening AA3 capital base is used as the starting point for determining the maximum revenue that Western Power may earn from the provision of covered services. The capital components of this revenue analysis are based on assumed changes in the capital base using a similar capital roll forward approach and the AA3 capex allowed by the Authority. Section 6.51A of the Access Code only allows expenditure to be included in the rolled forward capital base if it satisfies NFIT. Therefore our review is concerned with Western Power's capitalisation approach to the extent that it must ensure that Western Power only includes costs in its forecast AA3 capex that satisfy the NFIT requirements and, conversely, that costs that do not meet NFIT requirements are not capitalised. This issue is considered in Sections 7, 8 and 9 of this report.

6.4 INVENTORY

In its AA3 access arrangement information, Western Power has sought to add the value of its inventory assets to the AA3 opening capital base. The argument put forward for this change in regulatory accounting treatment is that the addition of inventory assets to the capital base will allow Western Power to earn a return on this investment to recover the financing costs that are incurred in holding those assets, which are needed for the efficient provision of covered services.

A depreciation allowance on inventory assets has not been sought by Western Power on the basis that an inventory asset does not commence its useful life until it is taken out of store and allocated for use on a specific maintenance activity or capital project.

6.4.1 Calculation of Efficient Inventory Levels

Western Power has proposed that only the costs of financing an efficient level of inventory should be recoverable

The elements of Western Power's inventory investment calculation are:

$$II = (RMC / ATR) + IS$$

Where:

II – Inventory investment

RMC – Regulated materials consumed

ATR – Asset turnover ratio

IS – Insurance spares

Regulated materials consumed is the value of inventory materials used for construction and ongoing maintenance. These assets are used daily with a large portion relating to planned maintenance, so inventory items in this category are reordered repeatedly throughout the year when they are taken from inventory for use on the covered network.

Asset turnover ratio identifies the forecast number of times per annum that inventory items in the *regulated materials consumed* category are turned over. The forecast ATR was determined by analysing Western Power's historical ATR. Western Power's ATR for transmission inventory in October 2011 was 1.27, while the ATR for distribution inventory was 2.19. The ATR incorporated in the AA3 access arrangement information reflects a target ATR of 3.0 to incentivise efficient inventory management.

Insurance spares are held specifically for assets that are of critical importance to the covered network. They are typically few in number and can have long lead times for delivery once ordered. Insurance spares safeguard against the possibility that an asset of importance to the network (for which they are a spare) could fail and require replacement. Since they are held as backup, insurance spares usually are not 'turned over' in a year, but instead held on an ongoing basis to respond to unexpected asset failures. They differ from strategic spares which relate to a specific individual asset, whereas insurance spares relate to a common type of asset (of which there is more than one). Strategic spares are not included within inventory

Western Power's forecast inventory levels during AA3 are shown in Table 6.1.

Table 6.1: Inventory for AA3 ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Transmission	20.04	28.54	31.44	28.96	28.54
Distribution	52.40	53.55	54.58	51.96	53.07
Total	**72.44**	**82.09**	**86.01**	**80.92**	**81.61**

Source: Western Power
Note: Includes real cost escalation.

6.4.2 Benchmarking

Western Power has benchmarked its inventory levels against other jurisdictions in terms of inventory as a percentage of the total work program, as shown in Table 6.2 and also on the basis of inventory value per km of network length as shown in Table 6.3. The table were provided by Western Power and we have not tried to reconcile data discrepancies.

Table 6.2: Interstate Comparison of Inventory Value to Works Program Size ($ million)

	Works Program Size	Inventory Value	Ratio of Inventory Value to Program Size
Western Power	**1,226**	**74**	**6.0%**
Victoria	1,728	64	3.7%
New South Wales	5,086	135	2.7%
Queensland	3,960	216	5.5%
Tasmania	382	31	8.0%
Average	**2,476**	**104**	**5.2%**

Source: Western Power

Table 6.3: Interstate Comparison of Inventory Value to Line Length ($ million)

	Line Length (km)	Inventory Value	Inventory Value per km Line Length
Western Power	**95,374**	**81.85**	**72.00**
Victoria	163,053	63.91	391.95
New South Wales	294,991	135.02	457.71
Queensland	221,467	216.33	976.80
Tasmania	28,035	30.77	1,097,59
Average	**160,584**	**105.58**	**739.21**

Source: Western Power

6.4.3 Discussion

We recognise that there is a cost associated with financing inventory and that inventory is necessary to efficiently operate a network business. It therefore seems reasonable to include efficient inventory levels in the capital base. Western Power has provided benchmarking statistics that place its inventory levels at reasonable levels compared to network businesses in other jurisdictions and has proposed an ATR that exceeds its current inventory turnover. We are unable to comment on the efficiency of the proposed ATR in relation to other network businesses. The variation in projected levels of inventory for each year of the AA3 aligns reasonably with the works program for each of the succeeding years.

We note that in the AER's final determination for SP AusNet for the 2008-09 to 2013-14 regulatory period[29], an adjustment was made to inventory levels so that opex items such as nuts and bolts were not included in inventory to avoid inconsistencies with capitalisation policies. We asked Western Power if stores line items such as nuts and bolts were included in inventory and were advised that:

> *All items, including those of small value, are procured and accounted for as inventory. These items are transferred from inventory and recorded as CAPEX or OPEX upon utilisation*.

The level of inventory and the capitalisation value for the purpose of asset base inclusion should be consistent with the accounting policies of the business to ensure that all inventory is appropriately treated.

6.5 COST ESCALATION

In preparing its AA3 forecast, Western Power has provided both real and nominal values of the forecast expenditure, with 2011-12 being the base year for its real cost forecasts. However the real cost forecasts provided in its AA3 access arrangement information include real material and labour cost escalation. Hence where material and labour costs are forecast to differ from inflation, these differences have been included in the real cost forecasts.

This makes it difficult to examine and validate expenditure trends, since changes in expenditure from year to year will not necessarily reflect changes in work volumes. We therefore asked Western Power to provide its forecasts exclusive of any real cost escalation and we have used these adjusted forecasts for this review. Hence, should the Authority decide that it is appropriate to include real cost escalation in the approved capex and opex forecasts, these will need to be added back to the forecasts quantified in this report.

Western Power engaged independent consultants CEG to estimate the cost escalators that should be included in the forecasts. Specifically, Western Power requested cost escalators be developed for the 2011-12 to 2016-17 financial years, in real terms as at 31 December 2010 (financial year 2010-11) for the following inputs for Western Australia:

- labour costs, including:
    - Western Power's internal labour costs;
    - external labour costs; and
    - labour costs (including contracting costs) for the electricity, water and gas sector.
- material costs, including:
    - aluminium;
    - copper;
    - zinc;
    - crude oil; and
    - steel.
- other factors, including:
    - exchange rates; and
    - inflation.

The methodology used by CEG was to source predictions of prices for the relevant inputs, in the form of either futures prices or expert forecasts, and to rely on this data to develop its recommended escalators. Where futures prices were available and sufficiently liquid they were used these in preference to forecasts on the basis that these

29 AER, Final decision SP AusNet transmission determination 2008-09 to 2013-14 January 2008

represent the expectations of market price movements made by informed market participants.

CEG's estimates of real cost escalators are set out in Table 6.4 below:

Table 6.4: CEG Estimates of Real Cost Escalators

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
Aluminium	(0.9%)	2.8%	4.1%	3.9%	3.3%	2.6%
Copper	(5.3%)	(0.8%)	(0.8%)	(1.7%)	(2.4%)	(3.1%)
Zinc	(8.6%)	2.2%	2.5%	4.4%	3.8%	3.1%
Crude oil	(0.2%)	2.1%	1.6%	1.0%	0.7%	0.4%
Steel	(1.3%)	(2.6%)	0.7%	4.1%	3.4%	2.7%
Labour	1.9%	1.5%	3.1%	3.7%	3.1%	3.1%

Source: Western Power (AA3 access arrangement information, Appendix W1).

CEG's proposed labour escalators were based on the following factors:

- actual salary increases paid by Western Power up until 1 October 2010;
- salary increases outlined in the Western Power - CEPU Union Collective Agreement 2008, which operates until 1 October 2013; and
- escalation factors beyond this horizon were based on specialist consultant (Macromonitor) forecasts specific to the electricity, gas, water and waste (EGWW) services sector in Western Australia.

CEG recommended one set of cost escalators for both Western Power's internal and external labour costs, rather than two separate sets of escalators, given that both internal and external labour costs are largely driven by the same underlying factors.

The EGWW forecasts factored in the following assumptions and were used to estimate nominal escalation figures:

- an expectation that the recent slightly lower rate of wages growth in the EGWW sector would be short lived, with a gradual acceleration of wage inflation over the next few years given that the next phase of growth in the Western Australian economy, driven by growth in construction, mining and utilities, will drive up the demand for labour and put upward pressure on wages; and
- a downturn in the construction and minerals investment cycles starting around 2015, as well as an easing in the rate of employment growth in the EGWW sector.

As the Macromonitor specialist forecasts were generated in nominal terms, real escalation was determined by deflating the nominal forecasts of wages growth by an inflation forecast based on RBA data. The Macromonitor report provided the following three forecasts for labour cost increases:

- average weekly ordinary time earnings (AWOTE) for full time workers;
- wage price index (WPI) ordinary time hourly rate; and
- unit labour costs ($ wages per $ real gross value added.

In its derivation of labour escalation factors, CEG has preferred the use of AWOTE and used this measure to derive the labour cost escalation factors that were used in the expenditure forecasts in Western Power's AA3 access arrangement information. The Authority in the past has used WPI (more commonly referred to as labour price index or

LPI) as an appropriate real labour cost escalator. There are arguments for and against the use of AWOTE and LPI but we note that, in its more recent regulatory decisions, the AER has used LPI based escalators in preference to ones based on AWOTE forecasts.

We have reviewed both the CEG and Macromonitor reports and consider the approach used in estimating the various escalation figures to be reasonable. The inflation figures used are within the Reserve Bank of Australia's latest target range for inflation of 2% to 3% and thus appear to also be reasonable.

6.6 PEAK DEMAND FORECAST

6.6.1 Introduction

The network peak demand forecast is an important input to the development of the AA3 capex forecast, as peak demand is the primary driver of capacity expansion capex on both the transmission and distribution networks. This section reviews the methodology used by Western Power to prepare its demand forecasts.

Western Power's peak demand forecast for each year of AA3 is the forecast in its 2010 APR, which was the most recent demand forecast available at the time it prepared its forecast AA3 capex and opex requirements. Western Power reviews and updates its peak demand forecast annually prior to release of its APR. The review takes into account the previous year's actual peak demand and energy sales and incorporates more recent intelligence on changes to the drivers of electricity consumption.

Subsequent to submitting its AA3 access arrangement information Western Power has issued its 2011 APR incorporating a reduced peak demand forecast. However, for this review, we have assumed that the 2010 APR forecast remains valid. Nevertheless a comparison of the 2011 APR forecast with the forecast assumed for this review and an indication of the possible impact of this updated forecast on Western Power's AA3 capex requirement for transmission capacity expansion is provided in Section.7.2.6. Section 8.3.5 considers the possible impact of the reduced 2011 APR demand forecast on the capex requirement for distribution works.

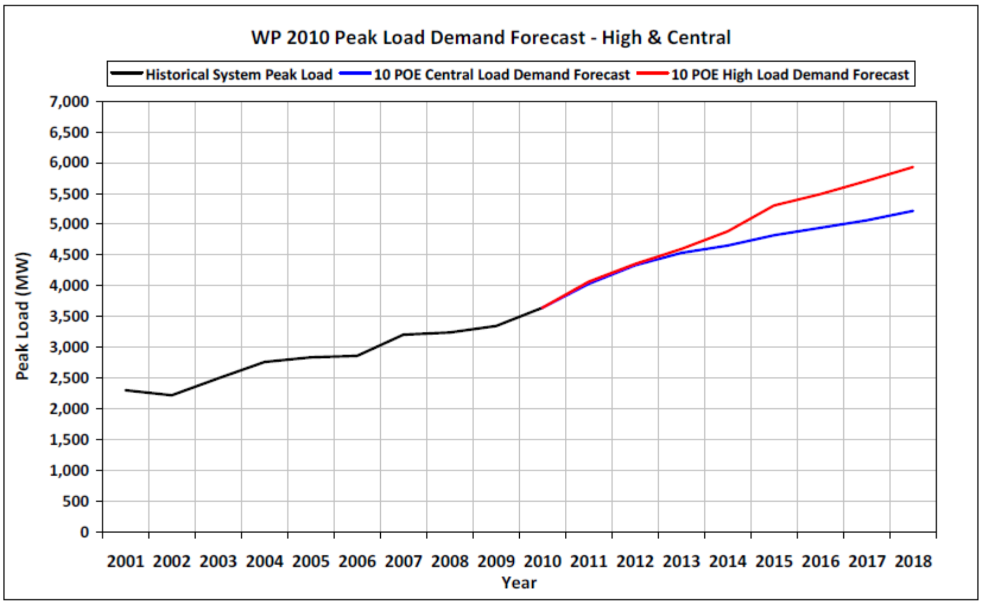
Table 6.5 shows the demand forecast used by Western Power for this review and this information is presented graphically in Figure 6.2. The "central" and "high" forecasts relate to different economic growth scenarios. However for each scenario there is still an element of uncertainty as electricity demand is affected by environmental factors such as temperature, which are not known in advance. The 10 POE forecast is the level within this range for which there is considered to be a 10% probability that the demand will be exceeded in any given year.

Table 6.5: Actual and Forecast Peak Demand (MW)

WP Historic Load	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Load Demand	2019	2263	2299	2216	2491	2760	2834	2856	3201	3238	3341	3639
WP Load Demand Forecast	2011	2012	2013	2014	2015	2016	2017	2018				
10 POE Central Forecast	4027	4332	4531	4654	4822	4940	5061	5216				
10 POE High Forecast	4065	4354	4598	4884	5302	5490	5705	5931				

Source: Western Power

Figure 6.2: Actual and Forecast Peak Demand



Source: Western Power

Western Power has indicated that it has used the 10 POE forecast for the central growth scenario as the basis for forecasting its AA3 expenditure requirement. Additional information on the assumptions underpinning the central growth scenario is provided in Tables.6.6 and 6.7.

Table 6.6: Central Growth Scenario Forecasts

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Peak Load Demand Forecast – Central Growth Scenario							
Actual peak demand (MW)	3,581						
PoE10	4,027	4,332	4,531	4,654	4,822	4,940	5,061
PoE50	3,874	4,173	4,366	4,482	4,643	4,755	4,867
Customer Numbers Forecast – Central Growth Scenario							
Total customer numbers	1,006,430	1,032,589	1,058,143	1,083,776	1,109,797	1,136,093	1,162,284
Sent-Out Energy Consumption Forecast – Central Growth Scenario							
Distribution-connected customers	13,907	14,421	14,856	15,246	15,654	16,080	16,517
Distribution system losses / streetlights	785	815	839	861	884	908	933
Transmission-connected customers	2,812	3,580	3,721	3,887	3,887	3,887	3,887
Total sent-out energy (exc. transmission losses)	17,505	18,816	19,417	19,994	20,425	20,875	21,337
Load Factor Forecast							
Forecast load factor (%)	54.20%	53.42%	52.63%	51.84%	51.06%	50.27%	49.48%

Source: Western Power

Table 6.7: Forecast Energy Consumption by Customer Class – Central Growth Scenario

Energy consumption (GWh)	2009/10 (Actual)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Residential	5,498	5,720	5,946	6,177	6,416	6,663	6,915	7,172
Small Business (<15 kVA)	828	867	900	926	951	976	1,003	1,031
General Business Small (15-100 kVA)	1,499	1,571	1,629	1,677	1,722	1,768	1,817	1,867
General Business Medium (100-300 kVA)	972	1,019	1,056	1,088	1,117	1,146	1,178	1,211
General Business Large (300-1000 kVA)	1,156	1,211	1,256	1,293	1,327	1,363	1,401	1,440
High Voltage (< 1MVA)	163	171	178	183	188	193	198	204
Customers (> 1MVA - high and low voltage)	3,304	3,347	3,457	3,512	3,525	3,545	3,567	3,592
Total distribution-connected customers	13,420	13,907	14,421	14,856	15,246	15,654	16,080	16,517
Growth (GWh p.a.)		487	514	435	390	408	426	437

Source: Western Power

6.6.2 Forecasting Methodology

Demand forecasting occurs at two levels. The high level forecasts looks at the overall growth in electricity consumption while at a detailed level the forecast considers where this growth will occur. It is this detailed forecast that determines where network capacity expansion is required. Western Power also uses the Independent Market Operator's (IMO's) Statement of Opportunities to inform its assessment as to where investment in network capacity expansion is needed.

Western Power relied on a range of data to develop its high level forecast. It has examined the historic correlations between changes in the key drivers of electricity demand and the actual demand experienced and, using external forecasts of how these drivers will change, calculated the probable impact of these changes on the likely demand for electricity.

Key drivers of electricity consumption that were investigated and assessed included:

- gross state product (GSP);
- air conditioner penetration;
- population growth; and
- government policy interventions including the carbon pollution reduction scheme (CPRS).

Data on these drivers was obtained from independent sources. The data indicated little change from previous trending and little change was therefore made to the high level forecasting approach.

Key inputs to the detailed forecast are actual summer and winter zone substation peak demands and the demand at each zone substation at the time of network peak demand[30]. This data is adjusted as necessary to allow both for the impact of abnormal operating conditions on the measured peak demand at individual substations and also for other extraneous factors that may have impacted the actual peak demand at a particular

[30] The peak demand at many substations will not occur at the same time as the peak demand on the network and the arithmetic sum of peak substation demands will therefore be greater than the network peak demand. In the industry, this is referred to as "diversity".

substation. The objective is to assess, as accurately as possible, the expected peak demand at individual substations under normal system operating conditions. Measured demand data is time synchronised to ensure that an appropriate snapshot of the network load dynamics is established and this is then validated against the summation metering at terminal stations. We consider this follows good industry practice.

Once base substation demand data is collated Western Power's OPAL demand forecast modelling tool is used to incorporate a number of additional inputs including historic peak demand, block load applications and historic variance adjustment factors to determine the POE. Historic peak demand consists of substation peak load data from up to 14 years past history. Economic activity is assessed at a local level through consultation with stakeholders, developers, as well as local and state government. The impact of this activity on local electricity demand is validated against the current rate of distribution load connection, block load applications and major access requests. These localised forecasts are then aggregated and calibrated against forecasts of overall state-wide activity.

Regression analysis is applied through OPAL using these inputs to obtain a forecast growth pattern. The forecast is then subject to historical variance adjustment statistically in OPAL using analysis to account for variance in the projected forecast.

Further to this, the probability of potential large individual loads (block loads) actually materialising and connecting to the network is considered and taken into account in finalising the forecast. The diversified block loads shown in Table 6.8 are included in the final forecast used as a basis for forecasting the AA3 expenditure requirements[31].

Table 6.8: Diversified Block Loads in AA3 Demand Forecast

Western Powers Major Block Loads (Diversified)	Central Forecast		High Forecast	
Projects (over 20MW)	Year	MW	Year	MW
Port and Pumping facilities for Grange Resources -SDN	-	-	2015	20
Southern Seawater Desal Plant	2011	16	2011	31
Stage 1 & 2 & 3	2012	15	2016	31
	2018	31	-	-
Simcoa 3rd & 4th furnace expansion project	2012	24.3	2012	24.3
	-	-	2016	24.3
Asia Iron Ltd's. - Extension Hill Mine Site	-	-	2014	112.5
Gindalbie Stage 1.1	2012	86	2012	86
Gindalbie Stage 1.2	2013	23	2013	23
Gindalbie Stage 2.1	-	-	2014	27
Gindalbie Stage 2.2	-	-	2015	45
Gindalbie Stage 2.3	-	-	2017	45
Gindalbie Stage 2.4	-	-	2018	45
Port of Oakajee Stage 1	2014	27	2014	27
Port of Oakajee Stage 2	-	-	2018	15
Oakajee Industrial Estate Heavy (Smelter)	-	-	2017	28
	-	-	2018	30
Grange Resources mine	-	-	2015	160

Source: Western Power

Western Power's approach to variance adjustment has considered the effects of temperature on electricity demand in some detail. However, unlike other states in the NEM, Western Power does not directly correlate demand with temperature since this can vary widely across the network and does not fully account for the observed historical demand variance. The variance analysis tool in OPAL therefore uses an algorithm based on historical demand variability.

31 The diversified block load is the assumed contribution of the load to system peak demand, which may not be the peak demand of the individual load.

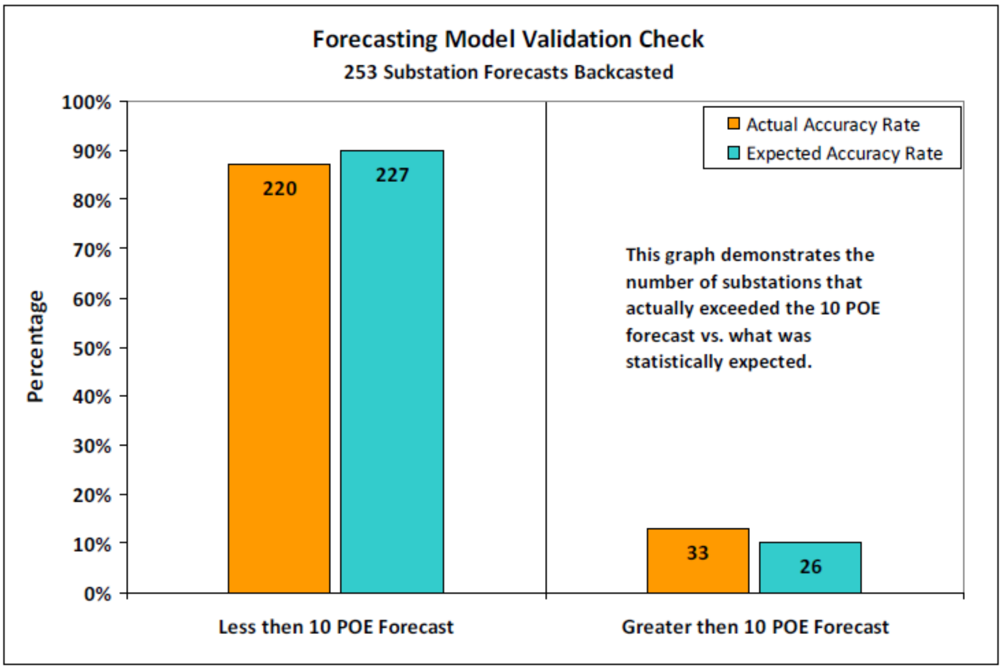
The impact of air conditioner load is also factored into the overall forecast. Increased air conditioner penetration has been a significant driver of demand growth in recent years and has resulted in a reduced load factor[32].

6.6.3 Validation of Demand Forecasts

Validation of both the model and methodology has been undertaken by Western Power in two ways.

1. Western Power assessed the number of zone substations where the actual peak demand fell within the forecast demand range (forecast demand +/- 10 POE). The results of this validation exercise are shown in Figure 6.3 and show a good correlation.

Figure 6.3: Validation of Forecasting Methodology



2. Western Power commissioned SKM MMA to provide an independent review of its demand forecasting methodology and its forecasts for electricity demand in the SWIS to assure stakeholders that the results, method and input assumptions are robust. SKM MMA generally concludes that the forecasting methodology adopted by Western Power is comparable with good industry practice throughout Australia[33].

   SKM MMA found that: the process and practices Western Power used in accessing and processing forecast input data are well established and technically sound; the treatment of load transfers and block loads (historical and forecast) is consistent with good industry practice; the calculation of trends in historic data and the forecast of future demands using regression analysis is technically sound; and that the forecasts produced by Western Power are robust and repeatable.

   We agree with this assessment.

[32] Load factor is the ratio of average demand to peak demand and is typically measured over a year. A reduced load factor indicates a more "peaky" load profile.

[33] Appendix S of the AA3 access arrangement information.

7. FORECAST CAPITAL EXPENDITURE - TRANSMISSION

7.1 INTRODUCTION

Western Power's forecast AA3 transmission capex broken down by regulatory category is shown in Table 7.1.

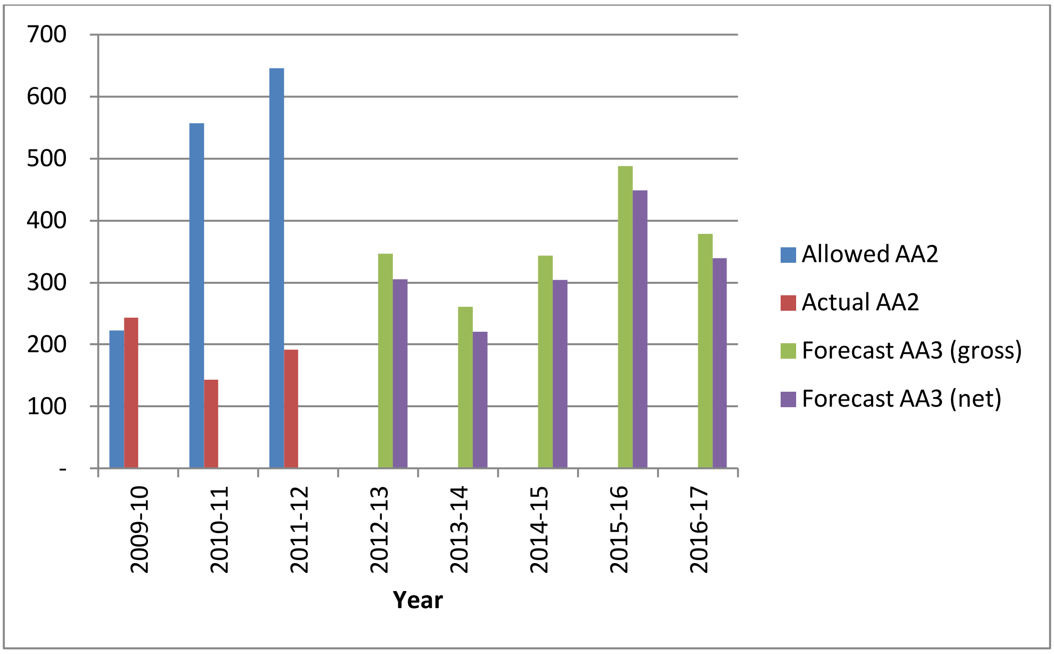
Table 7.1: Forecast AA3 Transmission Capex ($ million, real)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Capacity Expansion	215.6	128.3	204.1	338.5	226.2	95.1	222.5	134%
Customer Driven	72.1	71.2	70.5	69.9	70.7	51.4	70.9	38%
Less Capital Contributions	40.7	40.2	39.8	39.5	39.1	43.5	39.9	(8%)
Net Customer Driven	31.4	31.0	30.6	30.4	31.6	7.9	31.0	292%
Asset Replacement	30.3	32.7	32.8	32.7	34.0	20.9	32.5	55%
Regulatory Compliance	14.0	16.7	23.3	28.9	29.4	14.7	22.5	52%
Transmission Reliability	-	-	-	-	-	1.2	-	-100%
SCADA and Communications	14.2	11.9	12.9	18.3	18.0	9.4	15.1	60%
Total (net of capital contributions)	**305.6**	**220.6**	**303.7**	**448.7**	**339.2**	**149.2**	**323.6**	**117%**

Source: Western Power and GBA analysis.

A comparison of this forecast capex with the amount approved by the Authority for AA2 and Western Power's actual and expected AA2 expenditure is shown in Figure 7.1.

Figure 7.1: Comparison of Approved, Actual and Forecast Capex ($ million, real 2011-12)



Source: GBA Analysis
Note: Forecast AA3 (net) is net of capital contributions

The following is of note:

- Customer driven capex is partly funded by capital contributions from customers. In this report we focus on the forecast required capex net of capital contributions since this is the component that must be funded from Western Power's regulated revenue.

- Capex for capacity expansion is forecast to increase significantly in AA3 and is expected to be approximately 69% of the overall net transmission capex. Western Power has indicated that actual capacity expansion capex was lower than expected in AA2 because of the GFC. Furthermore, all non-critical capacity expansion expenditure was put on hold in 2010 while Western Power reviewed its approach to the planning of augmentation of the shared network and there is therefore a catch-up element in the AA3 forecast. This is discussed further in Section 5.

- Capex on asset replacement and regulatory compliance will each increase by more than 50% over the level invested in AA2. Western Power notes that it has an ageing asset base with many assets installed around the 1960s, a time of very high rates of growth in electricity demand, and that these assets are now coming to the end of their economic lives and requiring replacement. This is an issue for transmission network service providers in many developed countries. Regulatory compliance expenditure appears to be primarily driven by increased expenditure on wood pole replacement, which has become an area of high risk for Western Power.

- Western Power is not planning to incur significant expenditure in AA3 on capex projects targeted at improving the reliability of the transmission network. This is consistent with its AA3 objective of maintaining grid reliability at current levels rather than targeting improvements.

- The annual capex forecast for AA3 is significantly higher than the corresponding actual AA2 capex but nevertheless substantially lower than the capex allowed by the Authority for 2010-11 and 2011-12 in its AA2 access arrangement review.

In the following sections we undertake a high level review of each of these forecasts. The starting point is generally the actual and expected expenditure in AA2, with the expected expenditure in 2011-12 being the F1 review expenditure rather than the expenditure set out in Western Power's AA3 access arrangement information. We consider the drivers for each forecast and the validity of Western Power's submissions on the need for the AA3 capex.

We understand that Western Power's capex forecasts have been prepared on a bottom-up basis where each project or program is considered individually, largely independent of other projects or programs. While there has been a management challenge process to ensure that all forecasts are robust and justified by the needs of the network, the proposed expenditure is the sum of the individual project and program expenditures. There is little in the access arrangement information to justify the forecasts from a high level commercial perspective. This reflects the relatively weak constraints on the total level of expenditure that apply in a monopoly situation.

In a more competitive environment the total level of expenditure is much more important in the planning process since it impacts the price a business can charge for its services relative to the price charged by its competitors. Hence the total expenditure is the main budgetary constraint and the budget process becomes largely a matter of prioritisation within an overriding budget envelope. Risk management becomes more important as expenditure must be targeted at areas that are considered to pose the highest risk to the business. While, as a result of an iterative process, there may well be adjustments to the overall budget level when planning expenditure in a competitive environment, the total expenditure amount remains the overriding consideration.

In setting Western Power's revenue requirement for AA3, the Authority is approving the total capex (and opex) rather than approving each project or program individually. It is up to Western Power to determine how the expenditure is applied. In conducting our review of the capex forecast, we have therefore focused on changes in forecast expenditures from the expenditure levels in AA2 and focused on the factors driving these changes. As required by our terms of reference, we have also reviewed in detail a sample of specific capex projects and programs and the results of these reviews are presented in Appendix B. While these reviews have been informative they have not been the sole basis on which we reached our conclusions.

7.2 CAPACITY EXPANSION CAPEX

A breakdown of Western Power's forecast capacity expansion capex, and a comparison with the equivalent expenditure in AA2 is given in Table 7.2.

Table 7.2: AA3 Transmission Capacity Expansion Capex Forecast ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Fault Level	-	-	0.4	-	-	0.7	0.1	-89%
MWEP	174.8	27.8	3.7	5.9	27.6	13.6	47.9	254%
Supply	20.6	75.8	102.8	109.4	54.0	59.3	72.5	22%
Thermal	0.4	7.7	66.9	179.8	133.0	6.2	77.6	1,144%
Voltage	2.9	5.5	20.5	35.0	2.1	12.6	13.2	5%
Environmental	9.4	5.2	4.6	4.2	3.7		5.4	
Planning	7.6	6.3	5.3	4.3	5.7		5.8	
Total	**215.6**	**128.3**	**204.1**	**338.5**	**226.2**	**95.1**	**222.5**	**134%**

Source: Western Power and GBA analysis

The major components of this forecast are discussed in the sections below.

7.2.1 Mid West Energy Project

In its final determination on Western Power's pre-NFIT application issued on 27 January 2012, the Authority approved the construction of the MWEP for a cost of \$377.8 million (real 2009-10). We have not considered this further and understand that the Authority will add a provision to the capex forecast in accordance with its determination.

7.2.2 Supply

Capacity expansion capex is categorised as "supply" when it relates to increasing the capacity of zone substations[34] and the subtransmission network that delivers electricity to them. While it is classified as transmission by Western Power, similar work would normally be undertaken by distribution utilities in most other Australasian jurisdictions. The driver for this expenditure is growth in peak demand.

Of the \$362.5 million forecast AA3 expenditure, \$108.9 million (30%) is allocated to the installation of a new 80 MVA transformer at Cook St zone substation and construction of a new substation to reinforce supply to the CBD. This work is discussed in detail in Appendix B2. While we consider the new Cook St transformer reasonable, we are not satisfied that the construction of a new substation in the CBD during AA3 is consistent with the least cost approach to addressing the emerging supply issues within the CBD. Furthermore, even if a new substation is needed, based on the information provided by Western Power, we see little risk in deferring the project to AA4. We therefore suggest that provision of capex for a new CBD substation not be provided for in the AA3 capex forecast. This will provide time for Western Power to undertake a strategic planning study into CBD network augmentation. We think that such a study is needed to satisfy stakeholders that Western Power's planned augmentation and asset replacement projects within the CBD are consistent with a least cost development option.

The remaining \$253.6 million will fund supply augmentations in other areas of the network. Planned work includes the construction of a new 5 km 132 kV line to supply a new zone substation at Wanneroo East, the construction of nine new zone substations (including Balcatta and Waikiki where construction is already in progress) and installation of 18 new supply transformers at existing zone substations. This represents the addition of almost 900 MVA of new zone substation transformer capacity.

We considered the utilization of zone substation transformer capacity, based on the aggregated peak demand in each of Western Power's 15 load areas at the beginning and end of AA3. The analysis aggregated the 10 POE demand forecast for each load area and excluded load provided to direct connected customers, which does not pass through Western Power's zone substation transformers. A power factor of 0.95 was assumed. Based on the information provided by Western Power, we estimated a transformer utilisation of about 56% at the beginning of AA3, increasing to about 62% at the end of the period[35]. We conclude from this that, based on the demand forecast used by Western Power to prepare its AA3 proposal, the amount of new zone substation transformer capacity that is planned to be installed is not excessive and that prudent use is being made of existing spare capacity.

We note the following regarding transmission supply capacity expansion projects:

- The requirement for the installation of new zone substations and supply transformers is directly linked to demand growth. Should demand growth be lower than forecast then the program could slow down, implying a reduction in required expenditure. On the other hand, if demand growth is higher than assumed for the AA3 proposal, then the program would need to be accelerated and additional revenue would be required. Compared to transmission line construction projects, installation of new zone substations and transformers has a relatively short lead time. This means that project timing can be more easily regulated to match demand.

[34] Zone substations supply electricity to Western Power's distribution network.
[35] Excluding the proposed new CBD substation.

- Projects in this category typically have an estimated cost of less than $30 million and are not subject to the regulatory test under the Access Code. However, like all capex, they will be subject to an NFIT review before the expenditure can be included in the AA4 opening capital base. The stand-out exception with regard to the typical project size is the new CBD zone substation, with an estimated cost of $95.4 million, which is discussed above.

- Projects in this category are included in the investment adjustment mechanism as it is defined in the approved AA2 access arrangement.

Our proposed AA3 transmission supply capex is shown in Table 7.3

Table 7.3: Proposed AA3 Transmission Supply Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Western Power proposal	20.6	75.8	102.8	109.4	54.0
Removal of new CBD substation	-	(3.9)	(26.8)	(59.9)	(4.8)
Adjusted capex	**20.6**	**71.9**	**75.9**	**49.5**	**49.2**

Source: GBA

7.2.3 Thermal

Capacity expansion capex is classified as "thermal" when it is undertaken to augment the thermal capacity of the shared transmission network. As can be seen from Table 7.4, projects in this category tend to be large and involve the construction of new transmission lines or terminal stations.

Table 7.4: Forecast Transmission Thermal Projects ($ million, real 2011-12)

	Load Area	2012-13	2013-14	2014-15	2015-16	2016-17	Total
132kV double circuit cable from East Perth to new zone substation	East Perth / CBD	-	-	5.1	22.2	2.4	29.6
132 kV circuit from South Freemantle to Western Terminal	South Freemantle /Western Terminal	-	-	-	8.6	38.4	47.0
South Metro Reconfiguration	Kwinana	-	7.1	30.9	3.3	-	41.3
132 kV line from Mungarra to Geraldton	North Country	-	-	6.8	29.9	3.2	40.0
Replace existing wood pole 132 kV circuit from Muja to Kojonup with double circuit steel pole line	Muja	-	-	-	14.9	66.6	81.5
Second 132 kV line from Kojonup to Albany	Muja	-	-	12.5	54.6	5.9	72.9
New 330 kV Pinjarra terminal	Mandurah	-	-	7.6	33.3	3.6	44.6
New Eneabba 330 kV terminal station	North Country	-	-	2.9	12.7	1.4	-
Other projects		0.4	0.6	1.1	0.3	11.6	13.9
Total		**0.4**	**7.7**	**66.9**	**179.8**	**133.0**	**387.8**

Source: Western Power.
Note 1: Real price escalation not included.
Note 2: MWEP not included – see Section 7.2.1.

We note the following regarding transmission thermal capacity expansion projects:

- The Authority's approved AA2 forecast for thermal capacity expansion projects, not including the MWEP, was $412.3 million but only $18.6 million was actually spent. Of this $15.0 million was spent in 2009-10. The reason for this shortfall was Western Power's decision, following release of the Authority's AA2 decision, to put augmentation of the shared network on hold, pending a review of its transmission network planning processes. The forecast thermal capacity expansion capex for the five-year AA3 period (excluding Eneabba terminal station) is more than 10% lower in real terms than the expenditure approved by the Authority for the three-year AA2 period.

- Notwithstanding the effective freeze on this expenditure in AA2, there is little forecast activity in the first two years of AA3. We assume this is because projects of this nature normally have to undergo a lengthy statutory consent process and generally require individual regulatory approval. Hence they have a long lead time.

- The drivers for the projects vary. Some, such as the Muja-Kojonup-Albany line and the Mungarra-Geraldton line are purely load driven and could be deferred if forecast load growth does not eventuate. Others, such as the south metro reconfiguration are driven by more strategic network upgrade considerations and should probably proceed, irrespective of load growth[36]. Still other projects, and the Muja-Kojonup line may fall into this category, should proceed as they will allow assets that have reached the end of their economic life to be decommissioned.

- The new Eneabba 330 kV terminal station is required to support potential new wind generation projects around Eneabba, which have until now been unable to connect because of the limited capacity of the existing 132 kV connections to Perth. This constraint will be relieved with the construction of the MWEP. However the timing of this new generation capacity is speculative. The economics of wind farm development are still uncertain, notwithstanding the introduction of carbon pollution reduction scheme in 2012, and the consenting of new wind farm projects can take time. We suggest that this project not be included in the AA3 capex forecast at this time so that Western Power customers are not required to pay in advance for investments that may well not be required during AA3. Should there be a need for the project during AA3, it is open to Western Power to seek NFIT pre-approval and to rely on the IAM to ensure that its costs are recovered.

- We also propose that the 132 kV cable between East Perth and the proposed new CBD substation be deferred. This is consistent with our proposed deferral of this substation beyond AA3. In its strategic development plan for the CBD one issue that should be considered is whether a new CBD substation should be supplied from East Perth or whether there is merit in diversifying the sources of supply into the CBD for security reasons.

The projects in Table 7.4 will each present their own unique challenges and will still be at an early planning phase. Hence there will be a much higher level of uncertainty in the cost estimates than, for example, transmission supply projects. More accurate cost estimates will not be available until the projects have reached a more advanced stage of development.

Notwithstanding this, we think Western Power may have difficulty spending the forecast amount shown in Table 7.4 not necessarily because of delivery constraints but because of delays in securing the statutory and regulatory approvals most projects will require before they can proceed. Expenditure may be further reduced if the load driven projects are deferred because forecast load growth does not eventuate.

Irrespective of any potential for reducing this spend, we have no reason to believe that the forecast has not been prepared in good faith. As the projects are subject to the IAM, which means that the impact of any under expenditure will be returned to customers during AA4, we are not proposing any further modification to the Western Power forecast. We think that Western Power's improved governance procedures, together with the

[36] Western Power is reconfiguring parts of its 132 kV network in order to transfer load to its under-utilised 330 kV system.

regulatory approval process to which each project will be subject before expenditure is committed, should reduce the downside risk of inefficient overspend.

Our proposed AA3 transmission thermal capex is shown in Table 7.5

Table 7.5: Proposed AA3 Transmission Thermal Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Western Power forecast	0.4	7.7	66.9	179.8	133.0
Deletion of new CBD substation supply cable	-	-	(5.1)	(22.2)	(2.4)
Deletion of Eneabba terminal station	-	-	(2.9)	(12.7)	(1.4)
Adjusted capex	**0.4**	**7.7**	**58.9**	**144.9**	**129.3**

Source: GBA

7.2.4 Voltage

Capacity expansion projects classified as "voltage" include the addition of capacitors and other sources of reactive power to the network. These are required to permit high voltage transmission lines to operate at their full current carrying capacity and to maintain voltage stability under dynamic operating conditions.

Voltage projects account for less than 6% of Western Power's forecast AA3 capacity expansion capex. We have not reviewed these projects in detail since the level of forecast expenditure is comparable to the actual capex in AA2 and any recommended adjustments are unlikely to have a material impact on the approved total capex.

7.2.5 Environmental and Planning

As can be seen from Table 7.2, Western Power is forecasting an average annual capacity expansion capex of $11.2 million in AA3 for "environmental" and "planning". It expects an actual expenditure in these categories of only $4.3 million in 2011-12, and prior to that no expenditure was recorded against these categories as all expenditure was directly attributed to individual projects.

We asked Western Power to explain further the reasons for this apparent change to its capitalisation policy and were advised:

> *Under our works program model, Western Power does not create a specific project to address a network issue until gate 1. It [is] not until this point where planning and environmental costs, which are directly related to the project progressing, are included as part of the capital costs for an individual project. These costs are then included in the overall costs of delivering individual projects which are required to pass NFIT.*
>
> *For AA3 we have forecast an amount for planning and environmental costs based on the forecast costs of transmission capacity expansion projects. Planning costs are forecast in line with historical costs (between 1-3% of total project costs) varying by the type of project (e.g. greenfield / brownfield projects). Environmental costs are forecast in line with historical costs (based on 2% of total project costs).*
>
> *Planning and environmental costs are forecast as an individual item because the building block costs, on which our transmission capacity expansion projects are based, include only the components associated with design and execution of the project and do not include the planning and environmental costs associated with assessing options or planning the investment.*
>
> *In the instance where costs have been incurred on planning and environmental works as part of the investigation and development process, but a specific project does not go ahead at that time, these costs are capitalised. These costs are considered to meet NFIT, as they are incurred by Western Power undertaking the*

necessary analysis and planning activities required to identify and investigate options to address a network constraint or forecast breach of the Technical Rules.

We do not question the validity or need for these costs. However, we have not come across this accounting approach in other regulatory reviews. In our experience planning costs that cannot be attributed to a specific project are treated as opex and either recovered in full in the year that the expense was incurred or capitalised through a defined cost allocation process that allocates indirect or overhead costs directly to specific fixed assets in a transparent manner. We doubt that this treatment meets generally accepted financial reporting standards and have the following concerns about Western Power's proposed approach:

- It includes intangible assets in the register of fixed system assets. Unless encapsulated in a specific property right, such as an easement, such an asset has no value in that it does not provide any benefit to network users.
- Western Power has not specified how these assets will be depreciated.
- In a situation where these costs are applied to a project that does not proceed, we cannot see how the NFIT can be applied in order for the costs to be included in the capital base. For a start, each of the alternative tests in the second leg of the NFIT requires a benefit to be identified and this is not possible for an asset that does not exist in a tangible form.
- We cannot exclude the possibility of some double counting of Western Power's estimated costs. Western Power has based its forecast on typical historic costs, which are assessed as up to 3% for planning costs and 2% for environmental costs. However it also states that costs incurred after a project has passed gate 1 of the development process are attributed directly to the projects. These costs will have been double counted in the forecast if post gate1 costs form part of the historic cost assessment.

In our view, planning and environmental costs that cannot be attributed to an individual project should be treated as opex. If these costs are capitalised, it should be through a transparent indirect cost allocation process, where the costs are apportions across identified tangible assets.

7.2.6 Impact of Demand Growth

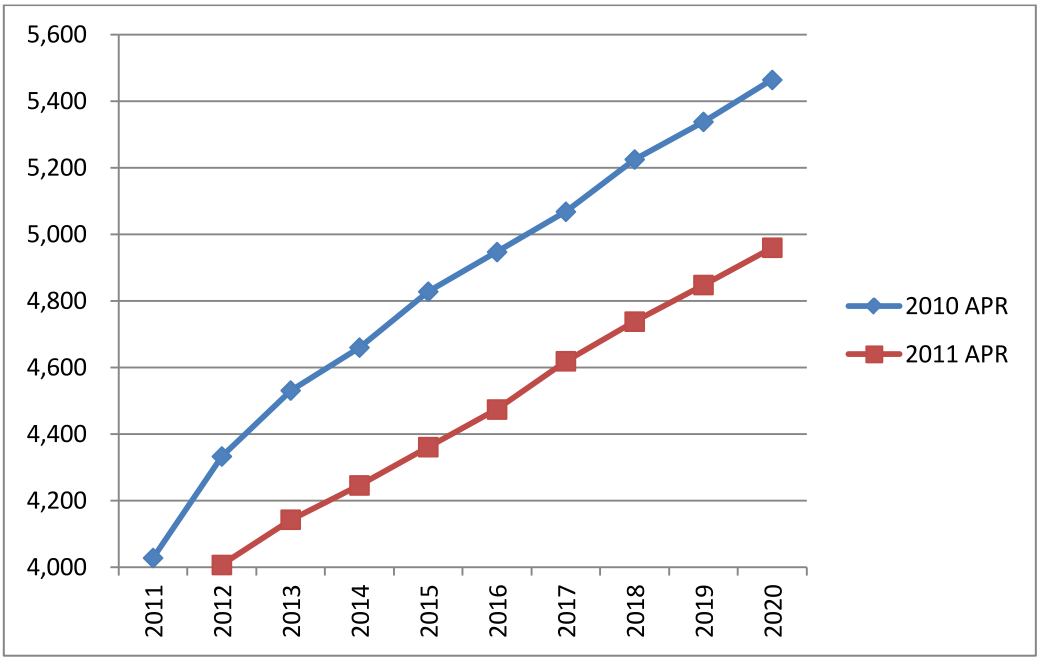
Capacity expansion projects are required to increase the power transfer capacity of the transmission network and are primarily driven by growth in network peak demand. This is particularly true of supply and voltage projects. Thermal projects tend to be larger and have longer lead times, which make it more difficult to match the rate of implementation to demand growth.

Western Power has indicated that it has forecast its capacity expansion capex on the basis of the 10% probability of exceedence (POE), central load forecast in its 2010 annual planning report (APR). The use of the 10 POE central forecast is consistent with good industry practice and we accept that the preparation of the capacity expansion capex forecast was based on the best information available at the time the forecast was prepared. However, subsequent to the submission of the AA3 access arrangement information, Western Power's 2011 APR has become available, with a lower load forecast. Given this, it is useful to consider at a high level the relationship between demand growth and capacity expansion capex requirements.

The 2010 APR forecast a 10 POE peak demand of 4,028 MW 2011 and 5,225 MW in 2018. However, in the 2011 APR the 10 POE forecast peak demand in 2018 was only 4,738 MW. This implies that, whereas the growth driven augmentations in Western Power's AA3 proposal were intended to support a growth in demand of 1,197 MW, on the basis of the 2011 APR provision for only 710 MW of demand growth is now required. This suggests that up to 40% of Western Power's growth driven capex could be deferred to AA4.

Figure 7.2 illustrates this from a different perspective. In the figure, the forecast peak demand in the 2011 APR is compared with the 2010 APR peak demand used for the preparation of the AA3 capacity expansion capex forecast. It can be seen from Figure 7.2 that the 2011 APR demand forecast lags the 2010 APR forecast by more than three years implying that, should the 2011 forecast eventuate, the capacity expansion and voltage capex forecast for the final three years of AA3 could be deferred to AA4, and the expenditure forecast for the first two years could be spread out over the whole AA3 period.

Figure 7.2: Forecast Network Peak Demands (MW)



Source: GBA analysis of Western Power demand forecasts.

Such a high level approach should be treated with some caution for the following reasons:

- There is uncertainty about load forecasting and the forecast in the 2012 APR will undoubtedly be different again. However if this theme of reducing load growth persists Western Power will undoubtedly be able to reduce its rate of investment in capacity expansion capex below the level proposed in the access arrangement information.

- Almost 43% of the forecast AA3 capacity expansion capex is categorised as "thermal" which, as discussed in Section 7.2.3, we think should be treated as less sensitive to demand growth. However this would not preclude some thermal projects being deferred should slower growth rates persist. Projects that could potentially be deferred include the 132 kV Mungarra-Geraldton and Kojonup-Albany lines. The double circuit line between Muja and Kojonup is another potential deferral candidate, although this line will also replace an existing asset, the condition of which is not known.

- The analysis is based on average load growth across the whole network when load growth across different parts of the network will vary. This will affect the optimal timing for the implementation of specific projects.

- Western Power has noted that delivery constraints have delayed the implementation of some projects beyond the date required to ensure compliance with the Technical Rules and this has increased customer's exposure to risk. While this merits further investigation, we suspect this comment applies mainly to the long lead time projects categorised as "thermal" that we do not consider should be deferred. While the concept of customer risk is considered further in the next section, it is nevertheless true that maintaining the proposed rate of implementation notwithstanding a reduction in load growth will reduce the level of risk to which customers are exposed.

Should the Authority decide to base the allowed growth capex on the 2011 APR the following adjustments would seem reasonable, based on a high level analysis.

- Our proposed transmission supply capex (Table 7.3) and Western Power's proposed transmission voltage capex (Table 7.2) each be reduced by 40%.

- The 132 kV Mungarra-Geraldton and Kojonup-Albany lines be deferred to AA4. We have some reservations about proceeding with the Mungarra-Geraldton project in its present form as it is not consistent with the proposed MWEP (northern section). Now that the southern section of the MWEP is to proceed, it becomes a sunk cost and cost benefit analysis of the northern section can proceed on its own merits. We suspect the northern section, which would be energised at 132 kV (at least initially), will be justified by its potential to connect wind and gas fired generation in the Geraldton area, rather than being needed to meet incremental and block load growth.

- Deferral of the Muja-Kojonup 132 kV double circuit line could also be considered. This project is discussed in more detail in Appendix B10. This discussion does not suggest that the condition of the existing line is a major project driver and indicates that there is some flexibility as to the timing of the work. On balance we think the project should be left in, as it is a significant project that is highly likely to be required in AA4, (assuming that the Southdown mine does not proceed). The potential to defer this project would allow other work to be brought forward without creating funding issues in the event that load growth forecast in the 2011 APR proves low.

Our proposed reductions to the transmission capex forecast to reflect the reduced load growth in the 2011 APR are summarised in Table 7.6.

Table 7.6: Proposed AA3 Transmission Capex Reductions for Reduced Load Growth ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Reduction in transmission supply capex	(8.2)	(28.8)	(30.4)	(19.8)	(19.7)
Reduction in transmission voltage capex	(1.1)	(2.2)	(8.2)	(14.0)	(0.9)
Deferral of the Mungarra-Geraldton line	-	-	(6.8)	(29.9)	(3.2)
Deferral of the Kojonup-Albany line	-	-	(12.5)	(54.6)	(5.9)
Adjusted capex	**(9.4)**	**(31.0)**	**(57.9)**	**(118.3)**	**(29.6)**

Source: GBA

7.2.7 Customer Risk

It is also helpful to consider the consequences of reducing the capacity expansion capex below the forecast level if the forecast growth rates prove accurate or, equivalently, not increasing capacity expansion capex should actual growth rates exceed the forecast.

Good industry practice requires a transmission network to be designed with a level of redundancy so that, in the event of an unexpected network element outage, peak electricity demand will continue to be supplied without interruption. Hence, under normal operating conditions, with all elements are in service, a typical network element will only be loaded to about 50% of its maximum capacity at time of peak demand. At other times, when the load is lower than peak, the load on a network element will be lower than this.

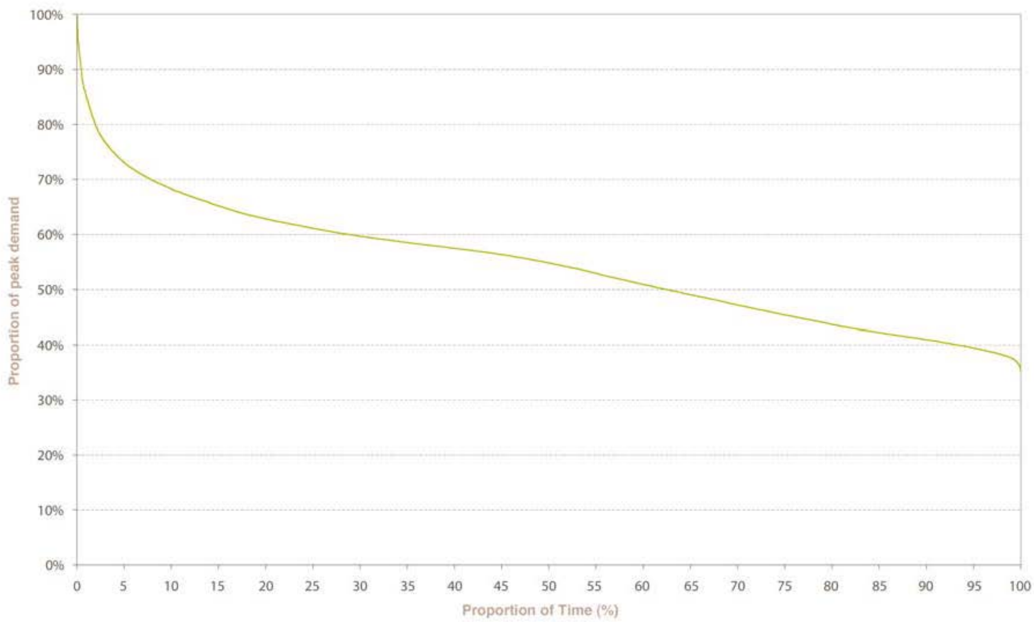
The level of redundancy, or security, designed into the network is specified in the Technical Rules and generally reflects good industry practice in developed countries. It varies with the quantity of load at risk and the perceived criticality of the affected load – for example loads in the CBD must continue to be supplied without interruption when there are two simultaneous network element outages, whereas in some other parts of the network continuous supply is required only for a single network outage. Some small substations supplying a low load may be supplied by a single line with no redundancy.

Western Power's capacity expansion plan is intended to ensure that there is no violation of the security standards in the Technical Rules so that risk of customer interruptions is maintained below what is considered an acceptable level[37]. If network capacity expansion investment is reduced relative to the network demand growth it does not mean that some customers will immediately be denied supply. However the network may need to be operated at an elevated level of risk at times of peak demand, meaning there is a heightened probability of customers losing supply should a network contingency occur at these times.

It should also be noted that this elevated level of risk would occur only for a limited time each year, when the demand on the network is high. Figure 7.3 is the load duration curve on the Western Power network and shows that the network will operate in excess of 80% of expected peak demand for less than 5% of the time and 70% of expected peak demand for well under 10% of the time.

Hence there is no "right" answer to determining the level of capacity expansion investment that is appropriate for a particular network assuming a given demand growth forecast. Rather it is a risk management decision requiring a degree of technical and commercial judgement.

Figure 7.3: Load Duration Curve for Western Power's Network



Source: AA3 access arrangement information, Figure 46, p115.

7.3 CUSTOMER DRIVEN CAPEX

As shown in Table 7.1, Western Power has forecast average annual gross customer driven capex to increase by 38% in AA3, from $51.4 million to $70.9 million. On the other hand, average annual capital contributions are forecast to reduce by 8% from

37 Western Power has developed a measure of network risk that it calls customers at risk (CAR). As described in Section 5.2 of the TNDP, the current level of CAR is elevated, indicating existing non-compliances with the security requirements of the technical rules. Based on the 2010 AMP load forecast and the AAI capacity expansion capex forecast, Western Power expects the level of CAR to increase in the short term, raising to a peak in 2015-16 and then reducing to full Technical Rules compliance by 2019-20. The reason for this short term increase is most likely that reducing CAR requires completion of some thermal capacity expansion projects and these have long lead times that cannot be accelerated.

$43.5 million to $39.9 million. The effect of this is that the net customer driven capex that must be funded from the revenue cap is forecast to increase from an annual $7.9 million in AA2 to $31.0 million in AA3.

We comment as follows:

- In its AA3 access arrangement information, Western Power has indicated that its gross customer driven capex forecast is based on historic levels adjusted for identifiable drivers. On this basis the AA3 forecast appears high, given that a 38% increase is much higher than the expected network growth rate.

- The reported level of capital contributions for AA2 appears to have been distorted by a total capital contribution of $80.9 million in 2011-12, shown in the F1 forecast. The reason for this abnormally high level of contributions is unclear, but at least part of this must relate to work undertaken in other years.

- Over the combined AA1 and AA2 periods, capital contributions offset on average 65% of gross customer driven capex. For AA3 Western Power has reduced the forecast capital contribution amount to 56% of gross capex. It has not provided any rationale for this reduction.

Forecasting customer driven capex requirements is very difficult because it is an area where Western Power must necessarily be reactive rather than proactive. However, we think that the forecast would better reflect historic trends if the following adjustments were made:

- The average gross customer driven capex in AA3 could be adjusted down so that it exceeds the AA2 average by only 10%. This is a better reflection of proposed network growth rates. The adjustment could be made by a pro-rata adjustment to the Western Power forecast; and

- The forecast capital contribution could be increased to 65% of the forecast gross capex.

These potential adjustments are shown in Table 7.7.

Table 7.7: Proposed AA3 Transmission Capex Adjustment for Customer Driven Capex ($ million, real)

	2012-13	2013-14	2014-15	2015-16	2016-17
Proposed gross customer access capex	57.5	56.8	56.2	55.8	56.4
Proposed capital contributions	37.4	36.9	36.5	36.2	36.7
Proposed net customer access capex	**20.1**	**19.9**	**19.7**	**19.5**	**19.7**
Western Power net forecast	31.4	31	30.6	30.4	31.6
Adjustment	**(11.3)**	**(11.1)**	**(10.9)**	**(10.9)**	**(11.9)**

Source: GBA

7.4 ASSET REPLACEMENT CAPEX

As shown in Table 7.1, Western Power's capex in AA3 on the replacement of transmission substation assets is forecast to average $32.5 million per year, an increase of 55% on an average spend of $20.9 million per year during AA2. A breakdown of this forecast expenditure is shown in Table 7.8. It can be seen that the forecast increase in asset replacement is driven almost entirely by a substantial increase in the rate of replacement of indoor circuit breakers as discussed in Appendix B9.

It should also be noted that the asset replacement forecast shown in Table 7.8 relates only to substation assets as line replacement budgets including crossarm replacements and pole management are categorised as regulatory compliance. The reason for this is not clear.

Table 7.8: Forecast AA3 Transmission Asset Replacement Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Circuit breakers	4.4	5.3	6.1	6.5	6.8	6.1	5.8	(4%)
Current Transformers	4.0	4.5	6.8	4.9	5.9	4.2	5.2	23%
Disconnectors	1.3	1.2	0.6	0.8	0.6	0.7	0.9	36%
Power Transformers	11.9	2.5	1.8	2.4	1.8	3.5	4.1	16%
Protection	2.0	2.3	2.0	1.7	1.7	2.8	1.9	(32%)
Surge Arrestors	0.4	0.4	0.5	0.5	0.5	0.6	0.5	(30%)
Voltage Transformers	0.6	0.6	0.6	0.7	0.6	1.0	0.6	(40%)
Internal Circuit breakers	5.5	15.9	14.4	14.3	10.0	1.2	12.0	905%
Static VAr Compensator	-	-	-	1.0	6.1	-	1.4	
Other	-	-	-	-	-	0.7	-	
Total	**30.3**	**32.7**	**32.8**	**32.7**	**34.0**	**20.9**	**32.5**	**55%**

Source: Western Power and GBA analysis

The expected value of the transmission component of Western Power's capital base as at the beginning of AA3 is $2.85 billion, of which $1.29 billion (46%) is in-service substation assets (excluding land, SCADA and communications equipment). The average age of the asset base is not known but in the NMP[38], Western Power suggested an assumed expired life of 50% of the assumed economic life, which is within the range we would expect based on our experience with similar utilities. This suggests an undepreciated substation asset replacement cost of $2.58 billion, implying a substation asset replacement rate of 1.25%. This is not excessive.

As discussed in Appendix B9, we support the accelerated replacement of indoor circuit breakers, which we consider justified for safety reasons given the results of Western Power's condition assessments and the failures experienced in recent years.

7.5 REGULATORY COMPLIANCE CAPEX

Regulatory compliance capex is targeted at improving the level of compliance with Western Power's regulatory and legislative obligations. As shown in Table 7.1, Western Power power's regulatory compliance capex is forecast to average $22.5 million per year in AA3, an increase of 52% of the expected average annual spend of $14.7 million in AA2. A breakdown of this expenditure is shown in Table 7.9.

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Table 7.9: Forecast AA3 Transmission Regulatory Compliance Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Asbestos Removal	-	-	0.8	1.3	1.3	0.3	0.7	106%
Automatic Disconnectors	-	0.2	0.5	0.5	0.5	-	0.3	-
Bunding	0.3	0.4	0.5	0.7	0.6	0.9	0.5	(48%)
Cross-arm Replacement	1.2	1.6	2.6	3.7	4.3	1.1	2.7	150%
Noise Mitigation	1.5	1.5	2.1	2.4	2.5	1.2	2.0	67%
Non-complying Stays	0.9	1.1	1.2	1.2	-	1.1	0.9	(15%)
Pole Mgmt	6.4	7.6	9.6	10.5	10.6	5.2	8.9	72%
Portable Earthing	0.1	-	-	-	-	0.1	-	-
Protection	1.7	2.0	2.5	3.3	4.0	0.5	2.7	418%
Substation Building Upgrades	-	-	0.1	0.3	0.3	-	0.1	-
Substation Earthing	0.2	0.2	0.3	0.5	0.5	0.1	0.3	189%
Substation Safety Upgrades	0.6	0.6	0.8	1.3	1.3	0.7	0.9	24%
Substation Security	0.8	1.3	2.1	3.2	3.4	0.9	2.2	155%
Fire Wall	0.2	0.2	0.2	0.2	0.2	-	0.2	-
Total	**14.0**	**16.7**	**23.3**	**28.9**	**29.4**	**14.7**	**22.5**	**52%**

Source: Western Power and GBA analysis

Approximately half of the expected AA2 and forecast AA3 capex is for crossarm replacement and pole management. This is not unexpected, given the pressure on Western Power to improve the quality of its overhead lines in extreme and high fire risk areas. While the focus of this program is on distribution lines, Western Power also has a number of wood pole transmission lines running through areas of high fire risk. The other forecast expenditures in this category are all relatively small and, while we have not examined these programs in detail, the requirement for capex on each line item is briefly discussed in Western Power's Capex and Opex Report[39]. The expenditures have been carefully planned and appear justified.

7.6 SCADA AND COMMUNICATIONS

As shown in Table 7.1, Western Power is forecasting average capex of $15.1 million per year during AA3, 60% higher than the average annual capex during AA2. A breakdown of this expenditure is shown in Table 7.10. The bulk of the expenditure, and indeed the bulk of the increase over the expected AA2 spend, is on asset replacement. This capex is discussed in more detail in Appendix B4.

[39] Appendix A of the AAI, Section 6.4, p135.

Table 7.10: Forecast AA3 SCADA and Communications Capex ($ million, real)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Asset Replacement	5.9	10.2	11.1	13.7	14.9	6.5	11.2	73%
Core Infrastructure Growth	3.6	0.1	0.3	0.8	0.4	2.5	1.0	-59%
Improvement In Service	2.3	0.9	1.1	2.2	2.5	-	1.8	-
Performance & Regulatory	2.3	0.5	0.4	0.4	0.3	0.2	0.8	236%
Third Party Actions	0.1	0.1	-	1.2	-	0.2	0.3	21%
Total	**14.2**	**11.9**	**12.9**	**18.3**	**18.0**	**9.4**	**15.1**	**60%**

Source: Western Power and GBA analysis

Western Power's Capex and Opex Report states that this reflects the upgrade of the XA/21 master station in System Management's control room and the completion of a number of large microwave replacements.

In respect of the master station, the Capex and Opex Report states that[40]:

The existing XA/21 hardware was purchased in 2005 and has been operated continuously for more than five years. This has exceeded the current standard industry life of computer system hardware of five years. Like for like replacements for this hardware is becoming increasingly more difficult to source as they are no longer provided by the vendor. The threat of hardware failure is increasing indicated by disk failures observed on the system. Without the availability of replacement parts, the possibility of a major and irrecoverable failure increases significantly, placing the safe and reliable management of the power system at risk.

We are currently finalising the incremental upgrade strategy. More frequent incremental upgrades rather than less frequent major upgrades will reduce risk relating to hardware obsolescence and reduced support from the service provider. We are intending to enter a long-term joint utility maintenance plan contract late in 2016 with General Electric and other electric utilities which are expected to reduce future upgrade costs.

With regard to microwave links the Capex and Opex Report states[41]:

In AA3 we will invest $12 million to complete works to replace the Muja to Merredin microwave bearer and commence the Goldfield Alcatel microwave replacement. These radio systems extend the communications backhaul network through areas where the use of optical fibre or other cables is uneconomical.

In order to reduce the risk of lengthy failures[42] posed by the existing microwave systems, a rolling program of asset replacement will remove Plesiochronous Digital Hierarchy (PDH) links that have been identified as presenting the highest risk and cost burden to Western Power with new, well supported, higher bandwidth and more flexible Synchronous digital hierarchy SDH50 microwave bearer links. Continued asset replacement of islanded and no longer manufactured microwave radio links with PDH - SDH compatible systems will facilitate migration from PDH to SDH.

We acknowledge the importance of SCADA and communications assets to the operation of the power system, including the transmission network, and find the explanations on the need for major asset replacement capex during AA3 plausible. However, our ability to

[40] Appendix A of the AAI, p132

[41] Appendix A of the AAI, p133

[42] The report also notes that parts on some existing microwave links are obsolete and no longer supported by the manufacturer. Hence a failure would result in the system not being available for a significant duration.

assess the need for this expenditure is limited by the lack of coverage of these assets in the NMP, notwithstanding the fact that the plan explicitly states that SCADA and communications assets are covered[43]. Unlike other asset categories, the NMP does not include any discussion of the type and number of SCADA and communications assets, their age and condition and the maintenance issues that need to be addressed. We suspect this is an oversight but it is nevertheless a significant shortcoming, given the importance of these assets.

The forecast annual asset replacement expenditure during AA3 represents 16% of the expected depreciated value of these assets at the beginning of AA3. This is not unreasonable given the relatively short life of many of the assets in this asset class and the indication that many of the assets are relatively old.

We note that much of the expenditure is related to master station hardware located in system management's control room. We considered whether the master station assets were included in the capital base and consequently whether master station asset replacement costs should be funded from regulated transmission revenues. Our concern arises from the ring fenced status of system management and the fact that system management's primary role is to manage the power system (as distinct from the transmission network) on behalf of the IMO. It appears that, while the IMO owns software associated with generator scheduling, the control room and master station are still owned by Western Power, and that the IMO does not pay rental for the use of these facilities. We did not find a documented agreement or contract between Western Power and the IMO that defined the boundary between Western Power and IMO owned assets or specified how power system control costs are to be apportioned. This, in our view, is not a satisfactory situation. It is possible that some costs are being carried by Western Power that would better be carried by the IMO in that they are primarily incurred so that the IMO can undertake its role as market manager.

We have not pursued this issue further and have accepted Western Power's position that it owns these assets and is responsible for their management. However we note that when an asset boundary is not clear it is not possible to accurately apportion costs. It is also possible for costs to be moved across the boundary, making control of these costs potentially problematic.

7.7 SUMMARY

Our suggested adjustments to Western Power's AA3 transmission capex forecast are shown in Table 7.11. These adjustments do not include changes to the MWEP budget but do include our expected impact of the reduced 2011 APR peck demand forecast on Western Power's transmission opex requirements. The impact of these proposed adjustments is shown graphically in Figure 7.4.

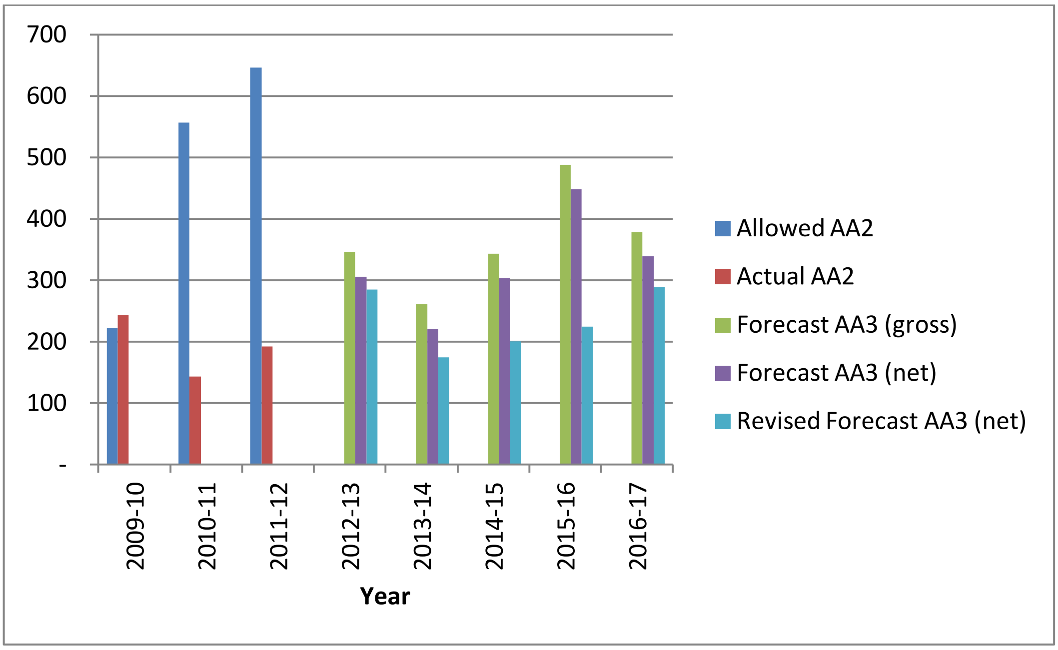
[43] Appendix L if the AAI, p2-2.

Table 7.11: Summary of Proposed Adjustments to AA3 Transmission Capex Forecast ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power Forecast (net)	**305.5**	**220.6**	**303.7**	**448.7**	**339.2**	**1,617.7**
Adjustments						
Deletion of CBD Substation	-	(3.9)	(26.8)	(59.9)	(4.8)	(95.4)
Deletion of new CBD substation supply cable	-	-	(5.1)	(22.2)	(2.4)	(29.6)
Deletion of Eneabba terminal station	-	-	(2.9)	(12.7)	(1.4)	(16.9)
Adjustment for reduced load growth	(9.4)	(31.0)	(57.9)	(118.3)	(29.6)	(246.1)
Adjustment to customer driven capex	(11.3)	(11.1)	(10.9)	(10.9)	(11.9)	(56.1)
Proposed revised forecast (net)	**284.9**	**174.6**	**200.1**	**224.9**	**289.1**	**1,173.6**

Source: GBA

Figure 7.4: Impact of Proposed Adjustments on AA3 Transmission Capex Forecast ($ million, real 2011-12)



Source: GBA

8. FORECAST CAPITAL EXPENDITURE – DISTRIBUTION

8.1 INTRODUCTION

Western Power's forecast AA3 distribution capex, excluding real cost escalation and broken down by regulatory category, is shown in Table 8.1. It should be noted that while capital contributions form part of the forecast, the capex net of capital contributions determines the required regulated revenue stream.

Table 8.1: Forecast AA3 Distribution CAPEX ($million, real 2011-12)

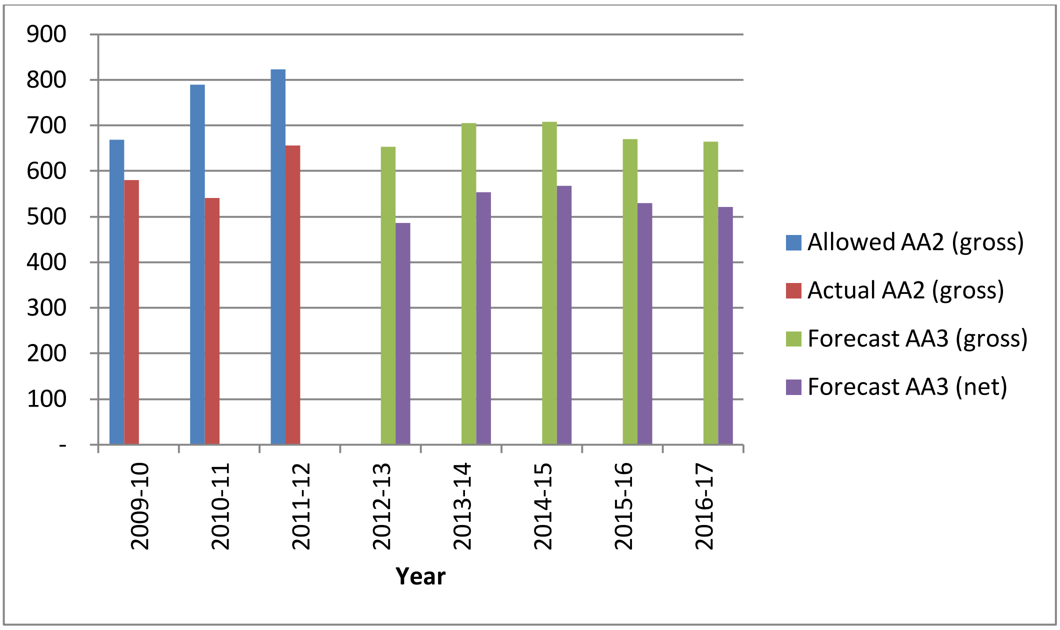
	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Gross Capex								
Asset Replacement	157.7	166.0	170.8	179.6	190.0	112.6	172.8	54%
Capacity Expansion	65.1	72.3	82.7	82.4	84.3	49.8	77.3	55%
Customer Access	204.8	202.6	206.3	205.7	209.0	220.1	205.7	-7%
Gifted Assets	64.3	64.3	64.3	64.3	64.3	68.3	64.3	-6%
Metering Asset Replacement	15.1	47.3	46.5	41.9	17.0	14.4	33.6	133%
Regulatory Compliance	99.1	103.4	103.6	72.7	78.4	77.0	91.4	19%
Distribution Reliability	0.6	0.6	0.6	0.6	0.6	11.4	0.6	-95%
RPIP	-	-	-	-	-	2.8	-	-100%
SCADA and Communications	4.8	5.7	6.6	3.8	6.7	3.5	5.5	60%
Smart Grid	2.5	23.9	26.2	19.7	15.0	6.1	17.5	185%
State Underground Power Program	39.2	18.9	-	-	-	26.5	11.6	-56%
Total Gross Capex	**653.3**	**705.1**	**707.5**	**670.6**	**665.2**	**592.5**	**680.3**	**15%**
Less Capital Contributions								
Gifted Assets	64.3	64.3	64.3	64.3	64.3		64.3	
Cash Contributions	72.8	73.1	76.0	77.2	79.9		75.8	
State Underground Power Program	29.4	14.2	-	-	-		8.7	
Total Capital Contributions	**166.5**	**151.6**	**140.4**	**141.5**	**144.2**		**148.8**	
Net Capex	**486.8**	**553.5**	**567.1**	**529.2**	**521.0**		**531.5**	

Source: Western Power

Table 8.1 indicates that asset replacement is by far the largest expenditure component forming 37% of the total net capex forecast. Other significant expenditures are regulatory compliance (20%) and capacity expansion (17%). While Western Power's forecast total capex on customer access is substantial, 68% of this is funded by capital contributions and the balance represents only 14% of the forecast net capex.

Figure 8.1 compares this forecast distribution capex with Western Power's actual capex during AA2 (including capital contributions) and also with the distribution capex allowed by the Authority in the AA2 review.

Figure 8.1: Comparison of Actual AA2 and Forecast AA3 Distribution Capex



The following sections consider in more detail each of the capex line items shown in Table 8.1.

8.2 ASSET REPLACEMENT

Western Power's forecast AA3 capex for the replacement of distribution network assets is broken down by activity in Table 8.2. The forecast average annual asset replacement investment of $172.8 million is 54% higher than for AA2. Expenditure on pole replacements and reinforcements is increased by almost 50% over AA2 and forms 76% of the total forecast. The remaining 25% provides for the replacement of other assets nearing the end of their economic lives. This trend of increasing asset replacement capex is consistent with the experience of other distribution network service providers, as assets installed during the high growth period of the 1960s and 1970s reach the end of their economic lives.

Table 8.2: Forecast AA3 Distribution Capex – Asset Replacement and Refurbishment ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Conductor management	16.9	16.6	18.0	18.3	19.3	11.3	17.8	57%
Overhead line refurbishment	4.8	4.7	-	-	-	0.2	1.9	780%
Pole management	115.8	123.3	130.9	138.6	149.1	89.0	131.5	48%
Protective device management	6.3	7.4	8.5	9.4	8.0	1.7	7.9	366%
Streetlights	2.3	2.2	2.2	2.2	2.2	2.2	2.2	1%
Switchgear management	4.8	4.8	4.4	4.3	4.4	2.1	4.5	121%
Transformer management	6.9	6.9	6.9	6.9	7.0	6.0	6.9	15%
Total	**157.7**	**166.0**	**170.8**	**179.6**	**190.0**	**112.6**	**172.8**	**54%**

Source: Western Power

8.2.1 Wood Pole Replacement and Reinforcement

Western Power is proposing an intensive pole replacement and reinforcement program in AA3, which is much more extensive than performed in the previous periods. This program is discussed in Appendix B12. As can be seen in Table 8.2, annual capex on distribution pole replacement will increase by 48% from $89.0 million in AA2 to $131.5 million in AA3 and is forecast to account for more than three quarters of Western Power's distribution asset replacement capex.

As discussed in Appendix B12 the poor condition of its wood pole population poses a high risk for Western Power because of the risk to public safety from unassisted wood pole failures and the potential for such failures to start bush fires that cause extensive property damage. Western Power's wood pole failure rate is two to four times higher than the Australian average and twenty times higher than that of the best Australian distribution network service providers. Its unassisted wood pole failure rate has been the subject of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament[44], an indication of the seriousness with which this issue is viewed by many stakeholders.

In September 2009, Western Power was issued with an Order by EnergySafety requiring all wood poles not meeting a prescribed standard to be eliminated by 2015. This Order followed EnergySafety audits into Western Power's management of its distribution wood pole population that were undertaken in 2007 and 2009. Following receipt of the Order, Western Power developed a new wood pole management plan (WPMP) for the late AA2 & AA3 periods that addressed its pole management program and pole inspection techniques. The objective of the WPMP is to ensure the replacement or reinforcement of the highest risk poles in order to: reduce the public safety risk arising from a failure of a wood pole particularly in rural areas; reduce the unassisted wood pole failures to rates comparable across Australia; and to continuously refine and improve Western Power's wood pole inspection and management approach.

In the WPMP, Western Power evaluated three investment models to achieve the above objectives and settled on an "optimal investment approach" that it considers complies with the intent of the EnergySafety Order. Its preferred approach is designed to ensure that specified pole replacements and/or reinforcements will be implemented as fast as practically deliverable even though the actual dates specified in the Order will not be met. This WPMP is based on Western Power's analysis of the requirements of the Order and the consequent replacement and reinforcement work necessary to meet these requirements, the perceived deliverability of this work and the impact that full compliance with the Order would have on the management of other business assets.

EnergySafety considers that the WPMP is inadequate as Western Power's preferred investment approach does not fully meet the Order's requirements. In its view, other strategies are available that would more effectively meet the requirements of the Order. These alternative pole reinforcement strategies have been considered and rejected by Western Power and a gap still exists between the parties. One reason for this appears to be that EnergySafety seems to be taking a short term view that is focused on achieving required safety outcomes as quickly as possible. Western Power, on the other hand, considers the EnergySafety approach undeliverable and prohibitively expensive and is seeking a solution that is deliverable and that will also minimise the longer term costs of addressing the problem. We have not attempted to resolve these differences, but consider that consultation should continue between Western Power and EnergySafety.

Western Power's proposed AA3 wood pole replacement capex, which totals $657.7 million, is the only first stage of Western Power's optimal investment program, which will require total capex of $2,560 million over a 15 year period.

Given the potential consequences of wood pole failures, we do not propose any reduction in the level of expenditure that Western Power has proposed for this program. There is a risk that the allowed capex for wood pole replacement in Western Power's approved AA3

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

access arrangement is treated as a cap by Western Power on the basis that expenditure above this level has not been provided for and therefore will not be funded. It has been suggested that this situation would be avoided if distribution wood pole replacement was included in the investment adjustment mechanism. We believe this proposal has merit and should be considered further.

The report of the Legislative Council's Standing Committee on Public Administration and the asset management audit undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program. Our view is that neither the issues in these reports, nor the differences between EnergySafety and Western Power as to how the wood pole failure problem is best addressed, should impact the amount of capex provided for wood pole replacement in AA3, particularly if a mechanism can be found that ensures that all efficient expenditure on wood pole replacement is reimbursed.

The information we have reviewed indicates that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented are achievable, particularly if Western Power successfully addresses issues related to records management. However any efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the actual expenditure.

8.2.2 Conductor Replacement and Line Refurbishment

Western Power plans to invest an average of $17.8 million per year on conductor management, an increase of 57% over AA2. In addition it is planning to spend $1.9 million a year on line refurbishment. While this latter expenditure is not large relative to other asset replacements it is a substantial increase above the AA2 spend. The primary purpose of both these programs is to reduce the risk of bush fires being started through conductors falling down or clashing. Given that the risk to Western Power of bush fires being initiated by poorly maintained assets is extremely high, we consider this a prudent investment.

8.2.3 Protective Device Replacement

Forecast capex during AA3 for the replacement of protective device is an average of $7.9 million per year, a substantial increase over AA2. The main purpose of this program is to address manufacturing issues with expulsion fuses, particularly in medium fire risk areas. This capex continues from AA2 as a ramped up program. In addition reclosers, surge arrestors and sectionalisers are planned to be replaced to address key performance and breakdown issues. We consider this capex reasonable.

8.2.4 Distribution Transformer Replacement

In AA3 Western Power plans to invest $6.9 million per year, amounting to 4% of total forecast distribution asset replacement expenditure, to replace distribution transformers. This is an increase of 15% over the AA2 period, reflecting an increase in the identified level of transformers needing replacement as well as the start of a voltage regulator replacement program. We consider this capex reasonable.

8.2.5 Switchgear and Streetlight Replacement

Forecast capex in these two categories is relatively small. There is some increase in the planned capex on switchgear replacement in AA3, which likely reflects an increasing maintenance need on an ageing network. We consider this capex reasonable.

8.3 CAPACITY EXPANSION

Western Power's forecast AA3 distribution capex for capacity expansion broken down by activity is shown in Table 8.3. It can be seen that average annual expenditure is forecast to increase by 55% over the average level in AA2.

Table 8.3: Forecast AA3 Distribution Capex – Capacity Expansion ($ million, real 2011-12)

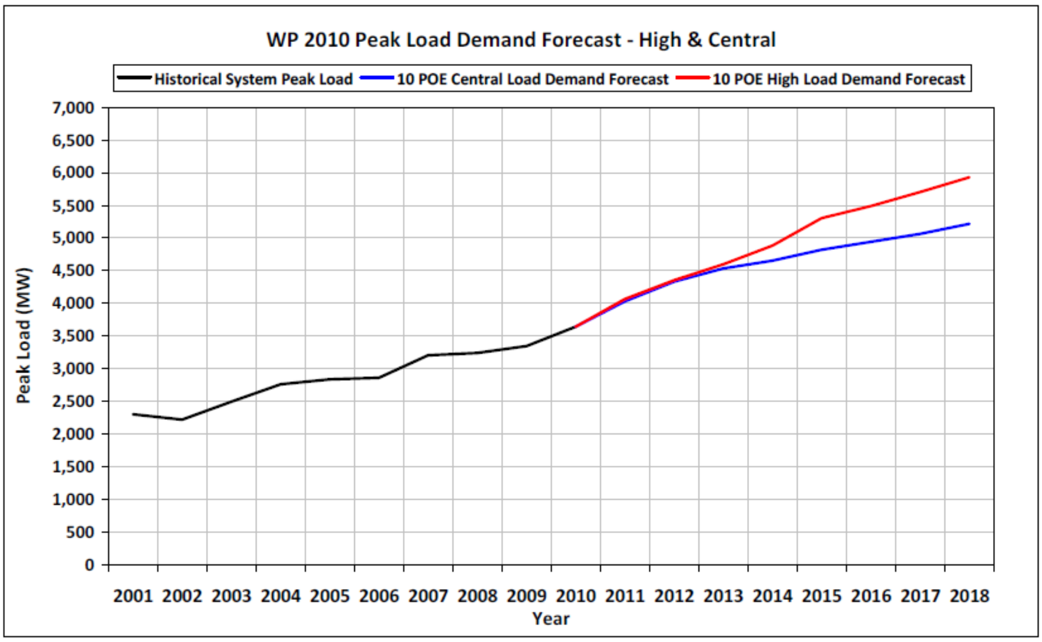
	2012-13	2013-14	2014-15	2015-16	2016-17	Total	AA2 Average	AA3 Average	Change
HV distribution driven	41.2	44.7	50.8	42.4	50.3	229.4	35.6	45.9	29%
HV fault rating and protection	5.5	6.4	7.8	13.7	14.4	47.9	0.2	9.6	
Overloaded transformers and LV cables	11.0	10.9	10.8	10.7	10.8	54.1	10.0	10.8	8%
Transmission driven	7.4	10.3	13.3	15.6	8.7	55.2	2.8	11.0	295%
Total	**65.1**	**72.3**	**82.7**	**82.4**	**84.3**	**386.7**	**49.8**	**77.3**	**55%**

Source: Western Power.

To support the growing demand for electricity, expansion of the capacity of the distribution network is needed through construction of new assets and increasing the capacity of existing assets including distribution feeders and distribution transformers. Capacity expansion projects are also triggered by the construction of new zone substations and the need to reconfigure and upgrade the distribution network to accommodate the new injection point. This capacity expansion is typical in the industry and generally consists of a small number of large and multiple small projects.

The network demand forecast used as the basis for the AA3 capacity expansion forecast was the 2010 APR forecast. Figure 8.2 shows a levelling off or depression in demand during the 2007-2009 periods and then an increase in demand during the 2009-2010 periods reflecting a potential need for increased capacity expansion capex in the distribution network during AA3.

Figure 8.2: Actual and Forecast Peak Demand



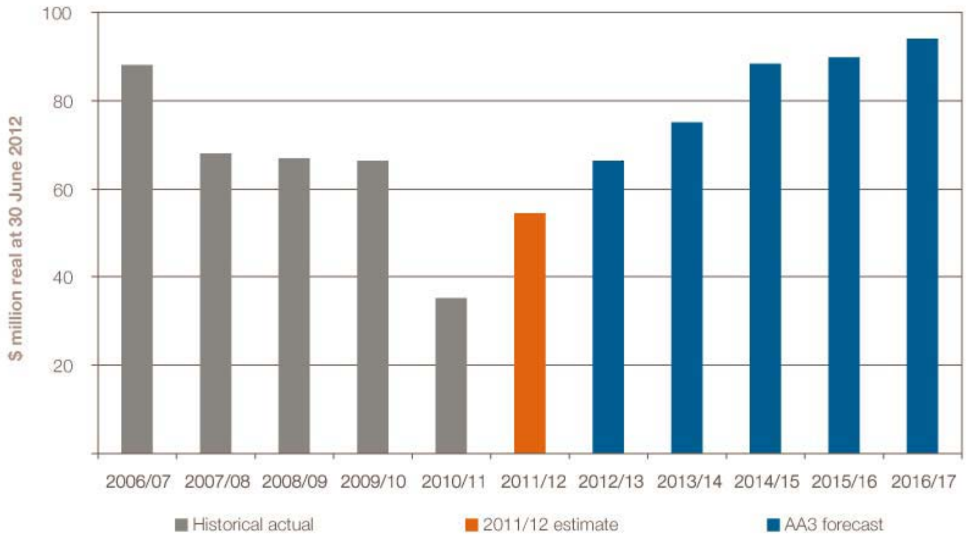
Source: Western Power

As noted in Section 5.2.1, Western Power deferred many transmission capex projects in early 2010 pending a review of its transmission planning strategy and this had an impact on actual AA2 expenditures. The forecast AA3 transmission capex is significantly higher than the actual AA2 expenditure and this will drive additional distribution capex due to the need to interface the transmission and distribution networks.

8.3.1 High Voltage Distribution Driven Projects

Western Power proposes investing $45.9 million annually on minor distribution network capacity expansion projects during AA3, an increase of 29% over AA2. This increase accounts for a catch up of deferred investment during the AA2, and focuses particularly on reducing risk of outages on highly loaded feeders. Figure 8.3 shows the constrained distribution capacity expansion investment during the final two years of AA2.

Figure 8.3: Distribution Capacity Expansion Capex ($ million, real 2011-12)



Source: Western Power.

Utilisation of some distribution feeders is greater than 80% which is high by industry standards. Reduced distribution feeder utilisation may allow greater ability to transfer load between zone substations under contingency conditions, which in turn could defer the need to install additional zone substation transformer capacity. Losses will also be reduced with lower feeder utilisation. Reduction of high distribution feeder utilisations is consistent with good industry practice and we consider that Western Power's AA3 forecast minor distribution capacity expansion capex is reasonable.

8.3.2 Transmission Driven Projects

Forecast transmission driven distribution capex during AA3 averages $11.0 million a year, an increase of 295% over the AA2 expenditure. This capex is for projects that arise from the need to:

- maintain clearances between distribution and transmission assets as transmission lines are developed or augmented;
- provide distribution capacity to accommodate new zone substation capacity and interconnection;
- provide distribution feeder load transfer capability that enables utilisation of existing zone substation capacity; and
- rebalance the load on substation transformers to improve substation ratings.

For this expenditure category it is perhaps reasonable to compare the total expenditure in AA2 and AA3 against the actual and planned increase in the number of zone substations and transformers commissioned during the respective regulatory period. During AA2 Western Power commissioned five new zone substations and 15 new power transformers. In AA3 it is planning to commission ten new zone substations (including a new substation in the CBD) and 17 new power transformers. Actual expenditure in AA2 was $8.2 million whereas planned expenditure during AA3 is $55.2 million. On the surface the increase seems high. However we are reluctant to simply reduce the planned AA3 expenditure on a pro rata basis since the actual AA2 expenditure appears relatively small given the number of new transformers and substations commissioned over the period.

Table 8.4 compares the actual and forecast transmission driven distribution capex as a percentage of the actual and forecast transmission supply capex for both AA2 and AA3.

Table 8.4: Comparison of Transmission Driven Distribution Capex with Transmission Supply Capex for AA2 and AA3 ($ million, real 2011-12)

	AA2			AA3				
	2008-09	2009/10	2010-11	2012-13	2013-14	2014-15	2015-16	2016-17
Distribution Capex – Transmission Driven	6.7	0.2	1.5	7.4	10.3	13.3	15.6	8.7
Transmission Capex - Supply	98.0	38.1	42.0	20.6	75.8	102.8	109.4	54.0
Distribution %	7%	1%	4%	36%	14%	13%	14%	16%

Source: GBA

As can be seen from Table 8.4, the transmission driven distribution capex costs appear high in AA3 when compared to AA2, particularly in 2012-13. It is difficult to see why associated distribution costs should be, on average, greater than about 10% of the cost of the transmission equipment that drives this expenditure, even allowing for the fact that much of the distribution work would be underground and that there is likely to be a wide cost variance from project to project. We therefore propose that, for the purposes of the draft decision, transmission driven distribution capex be limited to 10% of the supply capex.

Our proposed adjustment to this line item is shown in Table 8.5.

Table 8.5: Proposed Adjustment to Transmission Driven Distribution Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Transmission Capex – Supply (Table 7.3)	20.6	71.9	75.9	49.5	49.2
Proposed Transmission Driven Distribution Capex (10%)	2.1	7.2	7.6	5.0	4.9
Western Power Forecast	7.4	10.3	13.3	15.6	8.7
Adjustment	**(5.3)**	**(3.1)**	**(5.7)**	**(10.6)**	**(3.8)**

Source: GBA

8.3.3 Overloaded Transformers and Low Voltage Cables

This is a program by Western Power to proactively identify localised points within the distribution network that are vulnerable to overload during the peak summer demand period and to alleviate the potential problem before it arises. Investment to improve overloaded transformers and low voltage cables is proposed at $10.8 million a year during AA3, increasing by 8% over AA2 expenditure. Given the growth rates forecast for AA3, we consider this expenditure reasonable.

8.3.4 Fault Rating and Protection

Capex for alleviating high voltage fault rating and protection issues is forecast to be $9.6 million a year during AA3. This is a new program designed to improve the ability of protection schemes to react quickly to faults and adequately discriminate with other assets. It is a regulatory requirement that the network is protected to ensure both safety of assets and the general public and property. As the network expands the fault levels increase and protection improvements and replacement of assets is necessary for both public safety and in maintaining asset integrity. Modern protection schemes provide a much higher level of information for more efficient operation of the network. We consider this investment reasonable.

8.3.5 Impact of Demand Forecast

In Section 7.2.6 we considered the impact of the 2011 APR demand forecast on Western Power's required transmission capex. We noted that the 2011 APR forecast that demand growth AA3 would be 40% lower than assumed when forecasting Western Power's AA3 growth capex requirements and that the actual requirement would reduce if this later forecast was assumed.

This logic applies equally to capacity expansion distribution capex. We suggest the following potential adjustments:

- Transmission driven distribution capex is directly related to the level of transmission driven supply capex. This suggests that this expenditure line item could also be reduced by 40%.

- A reduction in demand growth should also result in a reduction in the need for high voltage capacity expansion distribution projects. However we would not expect the correlation to be as direct as that for transmission driven capex. We therefore suggest that this line item be reduced by 20%.

We would also expect a reduction in demand growth to reduce the requirement for expenditure on overloaded transformers and low voltage power cables. However, this expenditure tends to be localised to isolated pockets within the network and determining the impact of a reduction in demand growth on this expenditure item is more difficult. On balance, we suggest this forecast be left unchanged.

The impact of these suggested reductions is shown in Table 8.6.

Table 8.6: Suggested Reductions for Reduced Demand Growth ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Transmission Driven Distribution Capex					
Proposed AA3 capex (Table 8.5)	2.1	7.2	7.6	5.0	4.9
Proposed adjustment (40%)	(0.8)	(2.9)	(3.0)	(2.0)	(2.0)
Minor Distribution Capacity Expansion Projects					
Western Power Forecast (Table 8.3)	41.2	44.7	50.8	42.4	50.3
Proposed adjustment (20%)	(8.2)	(8.9)	(10.2)	(8.5)	(10.1)
Total proposed adjustment	**(9.0)**	**(11.8)**	**(13.2)**	**(10.5)**	**(12.1)**

Source: GBA

8.4 CUSTOMER ACCESS

Western Power's forecast AA3 distribution capex for customer access is shown in Table 8.7. Compared to AA2, there is a marginal reduction in expenditure in real terms.

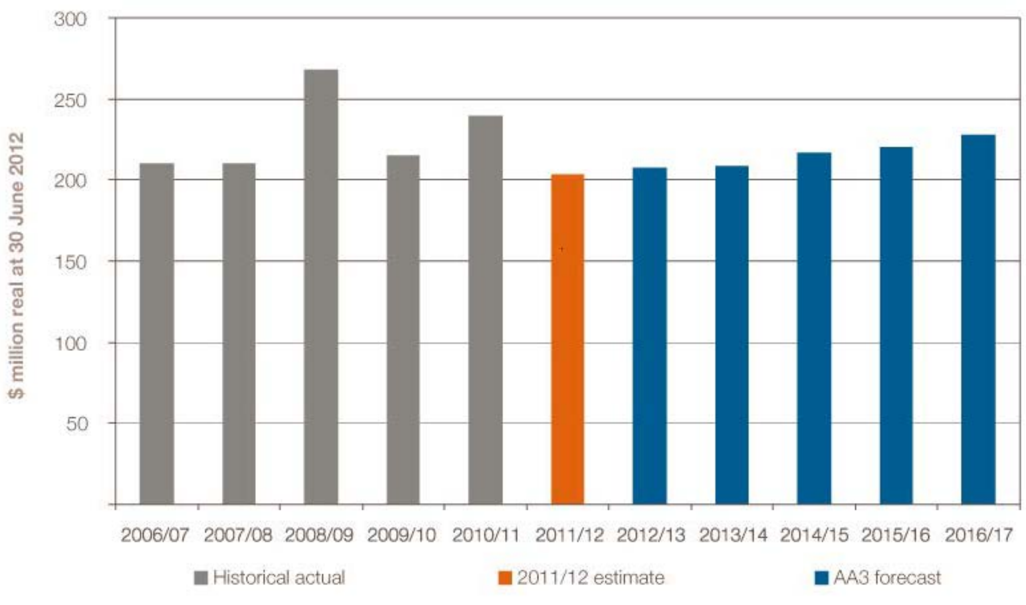
Table 8.7: Forecast AA3 Distribution Capex – Customer Access ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Gross Capex								
Network Extension	157.0	155.6	159.8	159.6	162.4	163.9	158.9	-3%
Subdivision	18.6	18.4	18.2	18.0	18.2	25.1	18.3	-27%
Connection	21.2	20.6	20.1	19.7	19.9	22.8	20.3	-11%
Relocation	8.1	8.0	8.2	8.4	8.5	10.8	8.2	-23%
Gifted Assets	64.3	64.3	64.3	64.3	64.3		64.3	
Total	**269.1**	**266.9**	**270.6**	**270.0**	**273.3**		**270.0**	
Less Capital Contributions								
Cash Contributions	72.8	73.1	76.0	77.2	79.9		75.8	
Gifted Assets	64.3	64.3	64.3	64.3	64.3		64.3	
Total	**137.1**	**137.4**	**140.3**	**141.5**	**144.2**		**140.1**	
Net Capex	**132.0**	**129.5**	**130.3**	**128.5**	**129.1**		**129.9**	

Source: GBA

Figure 8.4, which shows the gross customer access capex including real price escalation, but excluding gifted assets, shows that the forecast is relatively consistent with the level of expenditure incurred in past years.

Figure 8.4: Forecast Distribution Customer Access Capex ($ million, real 2011-12)



Source: Western Power

The main drivers for customer access capex are:

- the need to provide connection points for new customers connecting to the existing network as well as for the modification of existing infrastructure to connect new land developments to the network (where the distribution infrastructure within the development is gifted). This work is funded though tariff revenue, and also by customer capital contributions where the forecast tariff revenue is insufficient;
- requests for the relocation of existing distribution assets. These requests often come from government and local authorities rather than private landowners; and

- network assets gifted by developers requiring new land developments to be integrated into the Western Power distribution network.

Capital contributions, including contributions for both new connections and asset relocations during AA3, are forecast to average $75.8 million per year and gifted assets to be $64.3 million per year, as shown in Table 8.7. These forecasts are largely based on the contributions received during AA2.

Network extensions make up the bulk of the customer access capex with forecast annual capex of $158.9 million during AA3, marginally lower than AA2. This capex caters for customers connecting to the distribution network and includes: network extensions, new connection points and extension modifications to existing connection points.

Connection investment is forecast to be $20.3 million per year during AA3, a decrease of 11% from AA2. The number of new customers has been relatively consistent over the last two access arrangement periods and is expected to continue in this vein. Accordingly the forecast reflects this. Connection activities in this category consist of new or modified connections with either no network extension or a network extension of less than 100 metres.

Subdivision investment is forecast at $18.3 million a year decreasing by 27% from AA2. This reduction is primarily due to a reduction in land development resulting from a land lot build-up during 2008-10 during the global financial crisis. Subdivisions are market driven and there was less activity in the latter part of AA2.

Relocation capex is forecast at $8.2 million per year during AA3 decreasing by 23% from AA2. Relocation activities include relocated assets at the request of customers, government departments and are externally initiated and driven investments reflecting economic conditions.

Overall, customer access capex during AA3 is expected to be less than AA2. However customer access expenditure is very difficult to forecast as it is almost entirely outside Western Power's control. We consider Western Power's forecast reasonable.

8.5 METERING ASSET REPLACEMENT

Western Power's forecast AA3 distribution capex for metering asset replacement broken down by regulatory category for metering is shown in Table 8.8.

Table 8.8 Forecast AA3 Distribution Capex – Metering ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
New and replacement standard meters	13.6	13.4	13.3	13.1	13.3	14.4	13.3	-8%
Smart meters	1.5	33.9	33.2	28.8	3.7		20.2	
Total	**15.1**	**47.3**	**46.5**	**41.9**	**17.0**			

Source: Western Power

The expenditure covers two programs:

- The installation of meters for new connections and the replacement of existing meters. Western Power installs metering for about 26,000 new connections each year and, in addition, replaces about 30,000 existing meters a year;

- The installation of smart three phase meters. Western Power is required to replace 280,000 three phase meters by December 2015, after sample testing indicated that these meters do not meet accuracy requirements.

The 8% reduction from AA2 in the new and replacement meter component is likely due to the removal of the three phase meter replacement component from this line item as these meters will now be replaced under the smart meter line item. Western Power has stated that it installs 56,000 meters a year, of which one third are three phase. Of these 56,000 meters, 26,000 are new installations and 30,000 are replacements. These numbers are consistent with what we would expect. However if the replacement of 10,000 three phase meters is undertaken under the smart grid program, we would have expected the metering replacement program in AA3 to reduce by 18%. We therefore propose a reduction of 10% on Western Power's forecast AA3 capex for new and replacement meters.

We have reviewed Western Power's forecast costs for three phase meter replacement under the smart grid program in Appendix B6 and concluded that these costs were overstated by up to 15%. However, this analysis did not provide for the allocation of indirect costs to this line item. Even if allowance is made for this adjustment, the forecast cost of the program still appears high and we therefore propose a reduction of 5% to reduce the forecast to our expected requirement.

The smart meter replacement program is an accelerated asset replacement program and many of the meters replaced under this program will not have reached the end of their standard economic life. If the value of these meters is not written off through an accelerated depreciation adjustment to the capital base, then Western Power will continue to earn a return on the replaced mater, even though it has been taken out of service. If it is assumed that the age profile of the existing metering asset base is flat, then to a first approximation the value of the written off assets in real terms will be 50% of the forecast capex.

This does not apply to the replacement of single phase meters in the new and replacement meter program where it can be assumed that all meters replaced are life expired.

Table 8.9 summarises our proposed adjustments to Western Power's distribution metering capex.

Table 8.9: Proposed Adjustment to Distribution Metering Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
New and replacement standard meters					
Western Power forecast	13.6	13.4	13.3	13.1	13.3
Proposed adjustment	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)
Adjusted forecast	**12.2**	**12.1**	**11.9**	**11.8**	**11.9**
Smart meters					
Western Power forecast	1.5	33.9	33.2	28.8	3.7
Proposed adjustment	(0.1)	(1.7)	(1.7)	(1.4)	(0.2)
Adjusted forecast	**1.5**	**32.2**	**31.6**	**27.3**	**3.5**

Source: GBA

8.6 REGULATORY COMPLIANCE

Western Power's forecast AA3 distribution capex for regulatory compliance broken down by activity is shown in Table 8.10. Western Power's proposed capex is an increase of 19% over the average annual expenditure during AA2.

Table 8.10: Forecast AA3 Distribution Capex – Regulatory Compliance ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Bushfire management	39.2	39.9	40.0	44.1	48.5	32.0	42.3	32%
Conductor management	3.8	4.8	5.9	6.5	7.6	1.8	5.7	213%
Connection management	30.2	29.6	29.3	1.9	1.9	25.3	18.6	(27%)
Environmental management	0.3	0.3	0.3	0.3	0.3	0.5	0.3	(31%)
Low voltage planning	2.4	2.3	2.8	2.8	2.8	1.7	2.6	54%
Pole management	3.6	9.4	9.0	1.0	1.0	1.5	4.8	220%
Pole top management	1.9	1.9	1.9	1.8	1.8	2.4	1.9	(22%)
Power quality compliance	5.8	5.3	4.9	4.8	4.9	5.4	5.1	(5%)
Security	0.4	0.4	0.4	0.4	0.4	0.3	0.4	25%
Streetlights	1.4	1.4	1.4	1.4	1.4	3.3	1.4	(58%)
Supply to worst served customers	10.0	7.9	7.8	7.8	7.9	-	8.3	-
Total	**99.1**	**103.4**	**103.6**	**72.7**	**78.4**	**77.0**	**91.4**	**19%**

Source: Western Power.

Regulatory compliance capex is required to meet external regulatory and legislative obligations, and technical and safety requirements for the distribution network. The main drivers for proposed regulatory compliance investment in AA3 are in the areas of:

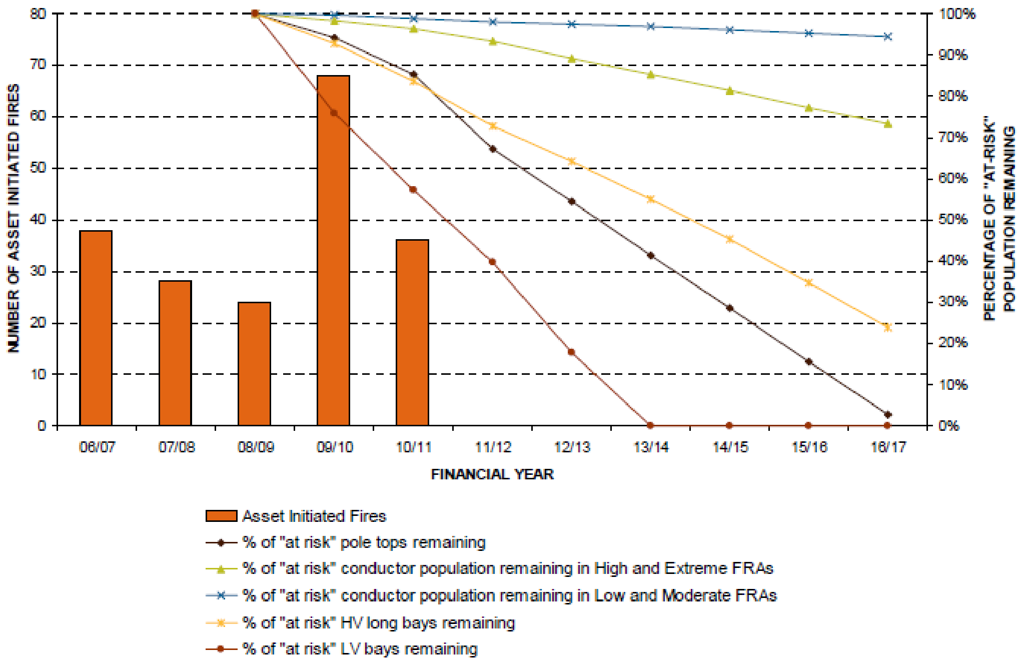
- Asset initiated bush fires. The proposed expenditure is targeted at replacing or refurbishing at-risk assets, particularly pole top hardware and conductors;
- Overhead service connection improvements for increased public safety;
- Reduction in the number of outages lasting more than 12 hours that trigger penalty payments in accordance with Section 19 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005.* This is discussed further in Section 10.6.4; and
- Low voltage network enhancements to meet the requirements of the Electricity Act 1945.

Regulatory compliance activities tend to be one-off projects or programs designed to address specific issues, such as mitigation of pole top fire risks. Once remedial action has been undertaken across the network, the program can stop. This can result in step changes in the investment profile and trending against earlier access arrangement periods can sometimes be misleading. In its proposed investment program Western Power has addressed each non-compliant area and designed an investment program to mitigate the problem. The following sections discuss the major capex programs.

8.6.1 Bushfire management

Figure 8.5 shows the impact of the various programs to be implemented during the AA3 period to mitigate the causes of asset initiated fires. The figure looks at each major cause and shows the percentage of the relevant assets that are expected to still be in service at the end of the AA3 period. In designing the bushfire management program Western Power has been cognisant of the number of asset initiated fires, which has increased during AA2. However it is thought that this increase may be due, at least in part, to an improvement in incident reporting and recording. On the basis of its own records, the Energy Networks Association's land management guidelines ENA DOC 019-200884 and the findings of the Victorian Bushfires Royal Commission, Western Power has developed a formal Bushfire Mitigation Strategy.

Figure 8.5: Analysis of Asset Initiated Fires



Source: Western Power.

This program is described in more detail in Appendix B14.

8.6.2 Connection Management

This forecast capex will fund the continuation of the overhead customer service replacement program that commenced in 2003 to address the risk of electric shock and possible electrocution as a result of faulty overhead customer services and to fully comply with Section 25 of the Electricity Act 1945. Western Power is planning to replace the remaining 43% of 130,000 at risk overhead customer service connections by 2014-15.

8.6.3 Conductor Management

This investment is a continuation of the program commenced in AA2 to correct conductors with low ground clearance over a 15 year period. During AA2, 4% of the required corrections were completed and 27% are programmed for completion during AA3. The remaining corrections will be completed in following regulatory periods. This compliance investment is driven by the Australian Standard (AS/NZS 7000:2010 Overhead Line Design – Detailed Procedures).

8.6.4 Power Quality Compliance

This program is driven by the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (Supply Code) and the Electricity Act 1945 and ensures that power quality complaints are investigated and corrected. The program is ongoing; however Western Power notes that as time progresses less complaints are being received which may suggest inroads are being made through this program.

8.6.5 Supply to Worst Served Customers

This is a new program in AA3 with an average annual expenditure of $8.3 million. It is designed to address the number of extended outages that require guaranteed service levels payments under the Supply Code. There are an increasing number of customers experiencing supply interruptions greater than 12 hours that entitle them to penalty payments under Section 19 of the Supply Code. Western Power proposes to address this compliance issue by targeting these customers over AA3.

This program is discussed in Appendix B1, where we noted that the primary cause of outages lasting 12 hours or more was Western Power's practice of isolating and making safe faults that occur in the late afternoon or during the night but leaving the actual repair until the next morning. While we agree that Western Power's proposed capex should remain in the forecast, we think Western Power should make more effort to restore supply immediately after a fault occurs, rather than leaving the repair to the following day.

8.6.6 Conclusion

More than 66% of Western Power's forecast regulatory compliance capex in AA3 is targeted at reducing bushfire risk and overhead service connection hazards. These are both high risk areas for Western Power. We consider that Western Power's strategy is robust and consider the forecast capex in all regulatory compliance categories to be reasonable.

8.7 DISTRIBUTION RELIABILITY

Western Power's forecast AA3 distribution capex for distribution reliability category is shown in Table 8.11.

Table 8.11: Forecast AA3 Distribution Capex – reliability ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Distribution reliability	0.6	0.6	0.6	0.6	0.6	11.4	0.6	(95%)

Source: Western Power.

Planned reliability capex in AA3 period is small compared to AA2 and reflects Western Power's perception that customers are generally satisfied with the level of service currently being provided. We note that the SSAM provides strong incentives for Western Power to maintain its current service levels. The planned AA3 capex is to research and develop new technologies and innovative solutions to improve network performance.

8.8 SCADA AND COMMUNICATIONS

Western Power's forecast AA3 distribution capex for SCADA & Communications broken down by category is shown in Table 8.12.

Table 8.12 Forecast AA3 Distribution Capex – SCADA & Communications ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Asset replacement	3.0	3.2	4.8	3.5	6.4	1.5	4.2	187%
Growth	0.5	1.4	0.7	-	-	-	0.5	-
Improvement in service	0.4	0.4	0.3	0.3	0.3	1.5	0.3	(79%)
Regulatory	0.9	0.9	0.8	-	-	0.3	0.5	73%
Total	**4.8**	**5.7**	**6.6**	**3.8**	**6.7**	**3.5**	**5.5**	**60%**

Source: Western Power.

While we have not examined this program in detail, we looked at the larger transmission SCADA and communications program and considered it reasonable. This is discussed in Appendix B4. Given that this is a smaller program, and that distribution SCADA is important to network functionality, we consider that the capex should be approved.

8.9 SMART GRID

Western Power's forecast AA3 smart grid capex is shown in Table 8.13.

Table 8.13 Forecast AA3 Smart Grid Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Smart grid	2.5	23.9	26.2	19.7	15.0	6.1	17.5	185%

Source: Western Power.

This program is discussed is some detail in Appendix B8. Salient points in the appendix are:

- The need to replace three phase meters provides a unique opportunity to initiate a smart grid program, since the metering costs (apart from the communications module) are, in effect, sunk and do not need to be included in the cost of the program;
- Western Power has undertaken thorough and detailed studies into the implementation of smart grid technology and the costs and benefits of rolling out such a program across the network;
- The studies show that, over a 20-year period, the net cost to Western Power of implementing a smart grid program will be substantial. Nevertheless, Western Power's studies show that these costs will be more than offset by the wider societal benefits and, if these are included, Western Power's analysis indicates a net benefit of $208 million over this time; and
- While the wider societal benefits have been quantified by Western Power, they are nevertheless highly speculative. We therefore strongly suggest that the benefits of the program be rigorously monitored on an ongoing basis and compared with the modelled results. We think there would be merit in independent involvement in this monitoring program.

We are not proposing that Western Power's proposed smart grid capex be reduced. It is nevertheless a high risk program; if the wider societal benefits do not materialise then Western Power will still carry the cost.

8.10 STATE UNDERGROUND POWER PROGRAM

Western Power's forecast AA3 distribution CAPEX for the state underground power program is shown in Table 8.14.

Table 8.14: Forecast AA3 Distribution CAPEX – State Underground Power Program ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Total SUPP capex	39.2	18.9			
Capital contribution	29.4	14.2			
Net SUPP capex	**9.8**	**4.7**			

Source: Western Power

Western Power proposes expenditure of $58.1 million in the first two years of AA3 to meet its obligations for Round 5 of the SUPP, which is expected to conclude in 2013-14. Of this, the state and local government will contribute $44 million which leaves a net funding requirement of $14.5 million as shown in Table 8.14. Western Power has a contracted commitment to the SUPP and therefore the capex is required.

There is currently no commitment to further rounds of the SUPP and additional capex for later years of AA3 has therefore not been included in the forecast.

8.11 SUMMARY

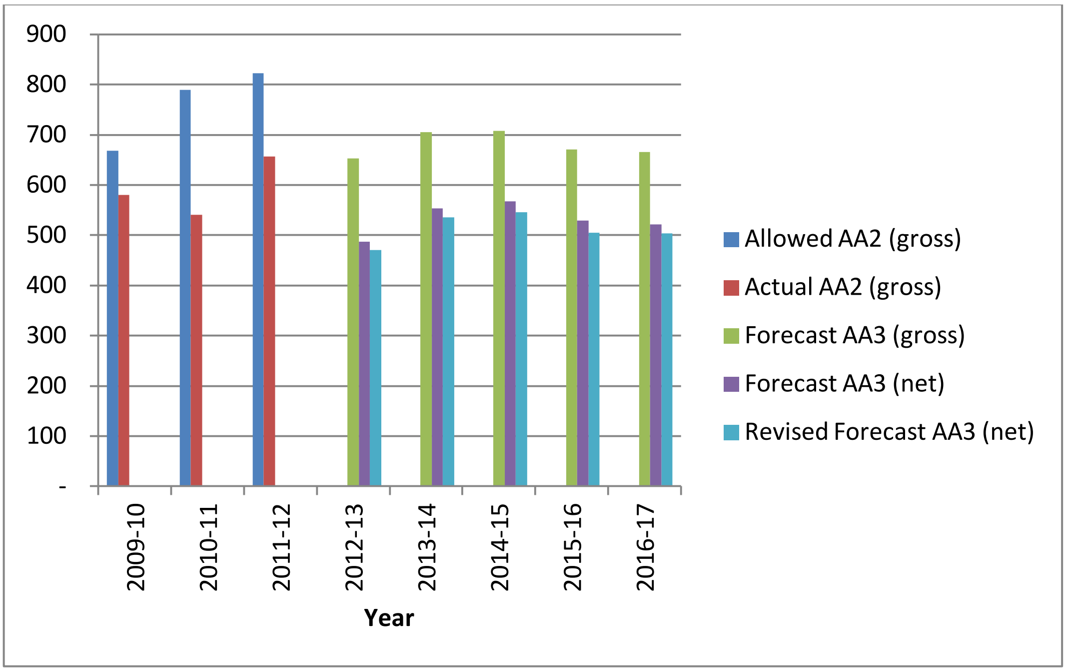
Our suggested adjustments to Western Power's AA3 distribution capex forecast are shown in Table 8.15. The impact of these proposed adjustments is shown graphically in Figure 8.6.

Table 8.15: Summary of Proposed Adjustments to AA3 Distribution Capex Forecast ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power Forecast (net)	**486.8**	**553.5**	**567.1**	**529.2**	**521.0**	**2,657.6**
Adjustments						
Transmission driven capex	(5.3)	(3.1)	(5.7)	(10.6)	(3.8)	(28.5)
Transmission driven capex (load reduction)	(0.8)	(2.9)	(3.0)	(2.0)	(2.0)	(10.7)
High voltage distribution driven	(8.2)	(8.9)	(10.2)	(8.5)	(10.1)	(45.9)
Standard meter replacement	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)	(6.7)
Three phase meter replacement	(0.1)	(1.7)	(1.7)	(1.4)	(0.20	(5.1)
Proposed revised forecast (net)	**471.0**	**535.5**	**545.2**	**505.3**	**503.7**	**2,560.7**

Source: GBA

Figure 8.6: Impact of Proposed Adjustments on AA3 Distribution Capex Forecast ($ million, real 2011-12)



Source: GBA

9. CORPORATE CAPITAL EXPENDITURE

9.1 INTRODUCTION

The total corporate capex included in Western Power's AA3 access arrangement information include two high level components – IT and business support as shown in Table 9.1 below:

Table 9.1: Forecast Corporate Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
IT	43.9	41.5	25.5	27.1	27.6	165.6
Business support	31.9	30.7	21.9	21.9	17.8	124.2
Total corporate	**75.7**	**72.2**	**47.4**	**49.0**	**45.5**	**289.9**

Source: Western Power

The majority of Western Power's AA3 program reflects corporate capex projects that commenced in AA2 including:

- property purchases;
- purchasing plant and equipment;
- refurbishing head office and major depots;
- replacing IT hardware and software; and
- delivering major enterprise systems transformations

The individual IT and business support components are discussed in the following sections.

9.2 INFORMATION TECHNOLOGY

The forecast IT capex is derived from Western Power's Enterprise Systems Asset Management Plan (ESAMP). In AA3, Western Power proposes to invest $165.6 million on IT infrastructure as broken down in Table 9.2.

Table 9.2: Forecast IT Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	% Total
Strategic program of work (SPOW)	26.1	23.5	7.3	7.8	7.3	72.1	43%
IT infrastructure	10.5	10.7	10.9	11.0	11.0	54.0	33%
IT business tactical	7.3	7.3	7.3	8.3	9.4	39.6	24%
Total	**43.9**	**41.5**	**25.5**	**27.1**	**27.6**	**165.6**	**100%**

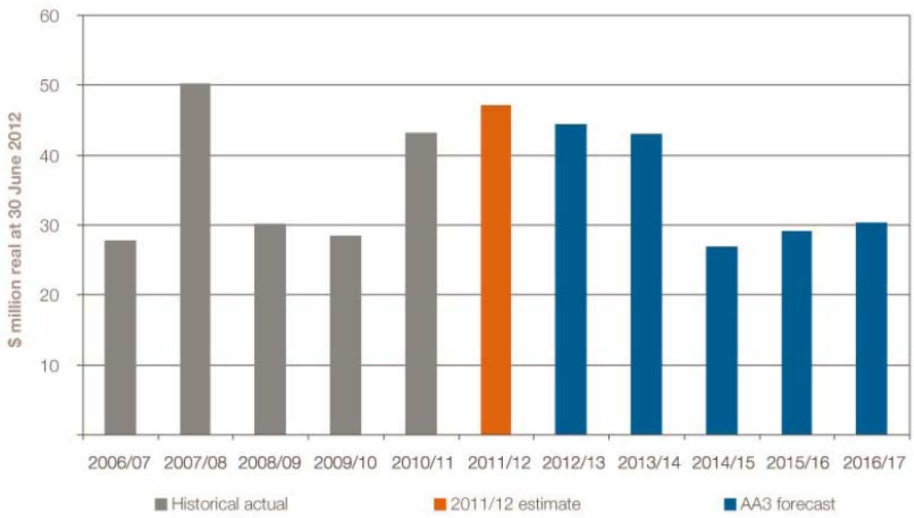
Source: Western Power

Western Power categorises its forecast capex as follows:

- *SPOW:* transformation initiatives involving the design, sourcing and execution of major enterprise level information systems implementation projects;
- *IT infrastructure:* IT hardware and software asset replacement, capacity upgrades to meet organic growth and implementation of new technology to improve operations; and
- *IT business tactical:* small enhancements to existing business systems

Figure 9.1 shows the trend in Western Power's business IT capex[45]. The forecast reduction in investment from 2014-15 reflects the completion of a number of SPOW initiatives in 2013-14.

Figure 9.1: Trend in IT Business Capex ($ million, real 2011-12)



Source: Western Power;
Note: AA3 forecasts include real cost escalation.

9.2.1 Strategic Program of Works

Western Power is proposing to invest a total of $72.1 million ($76.2 million if real cost escalation is included) in SPOW during AA3. Some of this capex represents a continuation of systems commenced in AA2 while others represent new expenditure items.

Some of the key elements are set out in Table 9.3:

45 Forecast AA3 capex includes real cost escalation.

Table 9.3: Forecast Enterprise Systems Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Ellipse	3.0	2.0	1.0	1.0	2.0	8.0
ESRI and Telvent products	2.0	1.0	-	-	2.0	5.0
Mincom field enablement suite	2.0	1.0	-	-	2.0	5.0
Primavera project portfolio management systems	2.0	1.0	-	1.0	-	4.0
Document management system	-	-	1.0	-	-	5.0
Business intelligence	2.0	2.0	-	1.0	-	5.0
Metering systems	2.0	10.0	12.0	-	-	24.0
Ariba			1.0	-	-	1.0
Oracle customer care and billing	2.0	1.0	-	1.0	-	4.0
DigSilent Powerfactory	-	0.5	-	0.5	-	1.0
Trouble call system – upgrade impacts	-	-	1.0	-	-	1.0
Forecast expenditure (ESAMP)	**15.0**	**19.5**	**16.0**	**4.5**	**4.0**	**59.0**
Asset management systems	3.0	3.0	3.0	3.0	3.0	15.0
Rescheduling of metering project	7.0	-	(12.0)	-	-	(5.0)
Cost escalation to 2011-12	1.1	1.0	0.3	0.3	0.3	3.1
Cost escalation after 2011-12	0.4	1.1	0.6	0.9	1.1	4.1
Total (AA3 access arrangement information)	**26.5**	**24.6**	**7.9**	**8.8**	**8.4**	**76.2**

Source: Western Power

The estimated costs shown in Table 9.3 reflect:

- the forecast capex identified in the ESAMP as at March 2011; and
- additional expenditure that has been subsequently identified prior to finalising the AA3 capex forecast including:
    - o forecast expenditure to enhance asset management systems beyond the core enterprise systems;
    - o reduced forecast expenditure for the meter data management project, due to the project being brought forward to a 2011-12 start; and
    - o cost escalation – split into before and after 2011-12.

We have reviewed the forecast SPOW IT capex requirement in more detail in Appendix B11. We consider that, on balance, the level and targeting of expenditure is reasonable. The forecast capex is much higher in the earlier years of AA3 as major system upgrades that were commenced in AA2 are completed. Costs in the later years are lower and represent ongoing incremental improvements.

9.2.2 IT Infrastructure

In AA3 Western Power is proposing to spend $54.0 million to replace IT infrastructure, which includes desktop computers, operating systems and desk top applications, printers and similar computer equipment.

Table 9.4 shows the forecast AA3 expenditure for IT infrastructure and compares the average annual AA3 forecast capex with the average AA2 capex.

Table 9.4: Forecast IT Infrastructure Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
IT infrastructure	10.5	10.7	10.9	11.0	11.0	7.4	10.8	45%

Source: Western Power

The increase in average annual capex in AA3 can be partially explained by the fact that, prior to 2010-11, Western Power was supplying infrastructure services to Verve Energy and Synergy and its IT infrastructure costs were partially defrayed through the charges to these entities for these services. In addition the residual costs were also charged back to the regulated business prior to 2010-11. If the impact of this change was adjusted for, the average annual AA2 capex would have been $11.2 million.

The AA3 forecast reflects growth in the number of users and the impact of new technology, which is largely offset by expected lower IT unit costs.

We consider Western Power's forecast capex for IT infrastructure to be reasonable.

9.2.3 Business as Usual

During AA3, Western Power is proposing to spend $42 million on "business as usual" capex to undertake ongoing minor business system enhancements. Western Power describes this as IT capex that will improve functionality, allow for process improvement and ensure compliance with incremental changes in network, energy market and corporate obligations.

Table 9.5 shows the forecast AA3 business as usual IT capex and compares the average annual AA3 forecast to the actual average annual AA2 capex.

Table 9.5: Forecast Business as Usual IT Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Business as usual IT	7.3	7.3	7.3	8.3	9.4	4.6	7.9	73%

Source: Western Power

Business cases for this capex category are submitted annually to the Business Reference Group (steering committee) to access funds and IT resources for undertaking these minor enhancements. Western Power claims that its business as usual forecasts are deliberately constrained below expected demand to force the prioritisation of candidate projects and avoid excessive tactical spend.

We note that business as usual IT capex in AA3 is forecast to increase by 73% per annum on average over its actual AA2 capex. Western Power considers that the increase is justified by the need to make minor enhancements to new systems developed under SPOW. However this overlooks the fact that, in general, the new systems replace legacy systems that were not designed to meet Western Power's current requirements and would likely require more maintenance. We suggest the forecast be reduced to the average AA2 level. This results in a total reduction of $16.8 million to the forecast, as shown in Table 9.6.

Table 9.6: Proposed Adjustment to Business as Usual IT Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power Forecast (net)	7.3	7.3	7.3	8.3	9.4	39.6
Proposed revised forecast	4.2	4.2	4.2	4.8	5.4	22.8
Adjustment	(3.1)	(3.1)	(3.1)	(3.5)	(4.0)	(16.8)

Source: GBA

9.3 BUSINESS SUPPORT

Western Power is proposing to expend $124.3 million in AA3 on capex for business support activities. This is disaggregated into two main expenditure categories - corporate real estate and property, plant and equipment (PPE). A breakdown of Western Power's forecast AA3 capex is shown in Table 9.7.

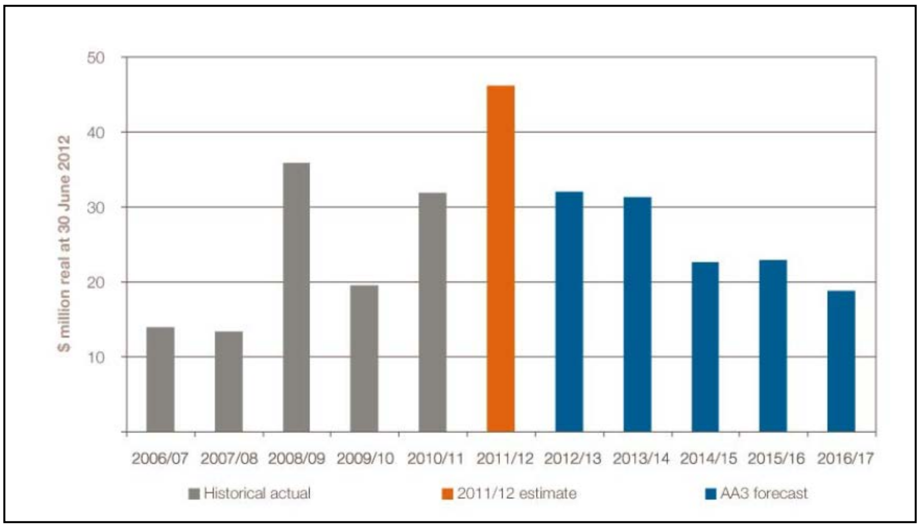
Table 9.7: Forecast Business Support Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Corporate real estate	25.9	24.8	15.9	16.0	11.9	94.5
Property, plant and equipment	6.0	6.0	6.0	6.0	6.0	29.8
Total	**31.9**	**30.7**	**21.9**	**21.9**	**17.8**	**124.2**

Source: Western Power

Figure 9.2, which includes real cost escalation, compares this forecast with Western Power's historic capex. The peak in business support capex, especially in the current 2011-12 year, reflects the staged works associated with Western Power's refurbishment of its head office and depot locations to comply with current building codes, remove asbestos and modernise the employee work environment.

Figure 9.2: Trend in Business Support Capex ($ million, real 2011-12)



Source: Western Power

9.3.1 Corporate Real Estate

Western Power is proposing to invest $94.5 million capex in AA3 on corporate real estate. Table 9.8 disaggregates this forecast by year and compares the average annual AA3 capex with the actual average annual AA2 expenditure.

Table 9.8: Forecast Corporate Real Estate Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Corporate real estate	25.9	24.8	15.9	16.0	11.9	23.2	18.9	(19%)

Source: Western Power

The predominant expenditure items relate to the refurbishment and construction of Western Power's head office and depot locations. Western Power has refined the capex forecasts for the refurbishment of the remaining floors at head office based on the actual spend on the floors refurbished in AA2. Forecasts for its depot sites have been based on historical trends and estimates from quantity surveyors.

The capex program also incorporates the construction of new depots at Busselton and Jerramungup to accommodate the increased capital works program. Land was bought for these works in 2008-09 due to existing site constraints.

We consider that the capex forecast is reasonable.

9.3.2 Property, Plant and Equipment

In AA3 Western Power is proposing to spend $29.8 million capex on PPE, which includes the purchase of capital items to support office and depot accommodation, as well as miscellaneous equipment and tool purchases.

Table 9.9 disaggregates this forecast by year and compares the average annual AA3 capex with the actual average annual AA2 expenditure.

Table 9.9: Forecast Property, Plant and Equipment Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Average AA2	Average AA3	Change
Property, plant and equipment	6.0	6.0	6.0	6.0	6.0	5.2	6.0	14%

Source: Western Power

Western Power has indicated that its AA3 capex forecast for PPE is based on an assumption of a continuation of the investment levels inherent in the 2010-11 forecasts. Table 9.9 basically reflects that premise and as such we believe that the proposed expenditure is reasonable.

9.4 INDIRECT COST ALLOCATIONS

In Section 10.9, we proposed a reduction in the amount of indirect costs allocated to opex on the basis that there was an unexplained increase of 17.3% in allocated indirect costs between 2010-11 and 2012-13. We calculated this adjustment by limiting the indirect costs allocation in 2012-13 to an increase of 1.26% over our estimated indirect cost allocation in 2010-11. This translated into a reduction in allocated indirect costs of 13.69%, which we suggested be applied across the board on a pro-rata basis.

In our view, a similar adjustment to the indirect costs allocated to capex is also warranted. The value of this suggested adjustment is calculated in Table 9.10.

Table 9.10: Proposed Adjustment to AA3 Indirect Costs Allocated to Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power allocation	136.0	138.9	145.6	153.5	144.3	718.3
Proposed adjustment (13.69%)	(18.6)	(19.0)	(19.9)	(21.0)	(19.7)	(98.3)

Source: GBA

10. FORECAST OPERATIONS AND MAINTENACE EXPENDITURE

10.1 OVERVIEW

The opex required by an efficient network service provider will depend on the size of the network under management and, for distribution network service providers, the number of network connection points. Regulatory approaches to forecasting future opex requirements typically categorise the different components of the opex forecast into recurrent and other expenditure. Recurrent expenditure varies with the size of the network and, for distribution businesses, the number of customers and is typically forecast using a scale escalation approach. However this approach is not appropriate for other expenditure categories, where forecasts are generally prepared using a bottom-up approach.

Forecasts of controllable expenditure using a base escalation approach typically:

- Use the actual opex in a selected base year as the basis for the forecast;
- Assess the actual base year opex for efficiency and reasonableness and make any necessary adjustments. Efficiency adjustments may be made to correct for inefficiencies identified in the efficiency assessment. Reasonableness adjustments are needed in areas where the base year opex can be shown to be atypical of future years and also to remove expenditures that may have been incurred in the base year but will not be incurred in future years. In assessing efficiency the regulator may consider the strength of the incentives on a business to improve its operating efficiency. It may also benchmark the actual performance against that of other service providers;
- Develop a base forecast for each year of the forecast period by escalating the base year recurrent expenditures in accordance with changes in the size of the network under management or changes in customer numbers;
- Apply economy of scale (EOS), capex/opex trade off and efficiency factors to the base forecast. EOS factors recognise potential economies of scale while the capex/opex trade off factor recognises that newly installed assets generally require less maintenance expenditure. Efficiency factors provide for potential improvements in operating efficiency over time;
- Adjust the scaled base forecast to account for non-recurring and one-off expenditures or the impact of other components of the forecast where the escalated base year forecasting approach is not appropriate;
- Prepare forecasts for other expenditure categories where the scale based approach is not appropriate using a zero based or alternative forecasting methodology; and
- Consolidate the component forecasts to form an aggregated forecast for each year of the forecast period. This aggregated forecast is used as the input to the revenue model.

10.2 WESTERN POWER'S FORECAST OPEX

Western Power's forecast opex, excluding real cost escalation, is shown in Table 10.1. The base year for the forecast was 2010-11 and the controllable expenditure categories where the forecast has been prepared using a scale escalation approach are shaded. Expenditure on other line items use an alternative forecasting approach and these line items are individually examined in Sections 10.4-10.6 below. Expenditure on non-revenue cap services is not included in the table, since these expenditures are not funded through the regulated revenue cap.

Table 10.1: Historic and Forecast Opex ($ million real 2011-12)

	AA2			AA3				
	2009-10	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**
Distribution								
Network Operations	14.3	14.5	16.7	15.5	16.0	16.5	17.1	17.7
Reliability	2.3	1.8	2.6	1.9	2.0	2.0	2.1	2.2
SCADA and Communications	4.0	4.9	4.2	5.3	5.4	5.5	5.7	5.9
Smart Grid	1.4	1.9	4.5	4.3	3.5	4.2	5.5	6.7
Maintenance - Corrective Deferred	20.6	28.0	22.4	29.9	30.5	31.3	32.1	33.6
Maintenance - Corrective Emergency	79.0	70.9	86.1	80.1	81.9	83.8	86.0	90.0
Maintenance - Preventive Condition	42.6	48.1	54.6	62.3	63.7	65.3	56.9	59.5
Maintenance - Preventive Routine	30.3	39.5	54.2	42.3	43.3	44.3	45.5	47.7
Non Recurring Opex	3.5	5.9	7.1	7.9	9.6	9.5	9.5	9.6
Call Centre	5.3	6.9	8.4	7.2	7.4	7.6	7.8	8.0
Distribution Quotations	12.0	8.3	4.1	4.1	4.2	4.3	4.3	4.3
GSL Payments	2.9	1.9	2.0	2.5	2.9	3.2	3.5	3.8
Metering	19.1	18.6	24.0	20.1	20.6	21.1	21.6	22.1
Total Distribution	**237.5**	**251.3**	**290.9**	**283.4**	**290.8**	**298.5**	**297.4**	**311.1**
Transmission								
Network Operations	9.5	8.8	11.1	9.4	9.7	10.0	10.4	10.7
SCADA and Communications	8.9	9.7	13.4	12.7	12.9	13.2	13.6	14.2
Maintenance - Corrective Deferred	6.3	10.2	9.0	10.9	11.2	11.4	11.7	12.3
Maintenance - Corrective Emergency	1.7	2.3	1.8	2.5	2.6	2.6	2.7	2.8
Maintenance - Preventive Condition	6.9	10.1	10.3	10.8	11.1	11.3	11.6	12.2
Maintenance - Preventive Routine	13.6	18.0	19.1	19.4	19.8	20.3	20.8	21.8
Non Recurring Opex	0.4	2.6	10.8	13.7	6.9	10.2	12.7	17.7
Total Transmission	**47.3**	**61.7**	**75.6**	**79.3**	**74.2**	**79.1**	**83.5**	**91.7**
Corporate								
Business Support	63.6	72.8	72.8	71.2	69.5	70.4	73.1	73.6
Insurance	14.3	19.8	25.0	25.9	26.8	27.4	28.3	29.1
Rates and Taxes	5.3	5.9	6.5	6.6	7.1	7.8	8.6	9.2
EnergySafety Levy	4.1	4.1	3.9	4.3	4.3	4.3	4.3	4.3
Total Corporate	**87.3**	**102.5**	**108.2**	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**
Total Western Power	**372.1**	**415.6**	**474.7**	**470.6**	**472.6**	**487.5**	**495.2**	**519.0**

Source: GBA, analysis of Western Power's AA3 opex forecast.

10.3 EFFICIENCY OF BASE YEAR EXPENDITURE

Western Power selected 2010-11 as the base year for its scale escalation forecasts as this is the latest year for which costs are available. In order to assess the efficiency of the base year expenditures we have:

- reviewed the incentives for Western Power to minimise its opex;
- benchmarked Western Power's base year opex against the opex reported by network service providers operating in the NEM; and
- reviewed, at a high level, the individual base year opex line items for reasonableness.

This assessment is discussed in the sections below.

10.3.1.1 Incentives to Minimise Opex

During AA2 Western Power was subject to a revenue cap that allows it to retain the difference between the forecast opex used to determine its allowed revenue for any year of the regulatory period and the actual opex incurred during that year. Hence there is a natural incentive for Western Power to minimise its opex since it can retain any underspend for a given year as profit.

In addition, the approved AA2 access arrangement included a gain sharing mechanism that allowed opex efficiency gains to be retained by Western Power for a limited period beyond the end of AA2[46]. This provided an even stronger incentive for Western Power to reduce its opex below forecast levels. However, clause 5.14C of the approved access arrangement provided that the gain sharing mechanism did not apply for any year in which Western Power did not meet all the service standard benchmarks included in the approved access arrangement.

As discussed in Section 4.1 Western Power's achieved service levels during the first two years of AA2 that were a significant improvement on those achieved during AA1 and met 34 of the 38 benchmark service levels specified in the access arrangement. However, as it failed to meet at least one of the benchmark levels in each of these years the gain sharing mechanism will not apply for either 2009-10 or 2010-11. In its AA3 application Western Power argues that, with the benefit of hindsight, the benchmark service levels were set so high that the expectation that Western Power could meet or exceed all benchmarks in any one year was unrealistic. We agree, and consider the probability that Western Power will meet all benchmarks for 2011-12 to be low.

We also note that, unlike many other jurisdictions, the gain sharing mechanism is asymmetrical, in that underspend but not overspend can be carried forward into the next regulatory period[47]. In circumstances where an efficiency gain is unlikely, this could create a perverse incentive to increase opex to inefficient levels, particularly towards the end of the regulatory period, in the hope that this will lead to an increase the regulatory opex provision in the following access arrangement period. We note this asymmetry because it is relevant to a consideration of the incentive on Western Power to reduce its opex and are not suggesting that Western Power has set out to game the regulatory arrangements in this way.

We conclude that there was an incentive for Western Power to minimise its base year opex but this incentive was not as strong as intended, given the low probability that Western Power could meet all necessary conditions for the gain sharing mechanism to apply. The lack of an effective gain sharing mechanism reduces the incentive for Western Power to minimise its base year opex. We note that, using a scale escalation model, a high base year opex will indicate a higher opex requirement in each year of the forecast period.

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[46] See clauses 5.13 and 5.14 of Western Power's approved AA2 access arrangement.

[47] Clause 5.14E of the approved AA2 access arrangement.

10.3.1.2 Benchmarking

Western Power is the only electricity network business in Australia to operate an integrated transmission and distribution network. This means there are no similar businesses in Australia with which Western Power can be directly benchmarked or compared. It would potentially be possible to disaggregate Western Power into its transmission and distribution components and to compare the individual components against transmission and distribution businesses in other parts of Australia. However this is also problematic as Western Power includes its subtransmission assets in its transmission component whereas the equivalent assets in other states are generally incorporated into their distribution businesses. Hence direct comparisons will not be valid.

To overcome this, we have aggregated the transmission and distribution businesses at a state level and compared Western Power with the aggregated operations in each state. Data for the aggregation was taken from reports published by the AER on its web site. This in itself was difficult since the AER does not publish a consistent data set covering all businesses. Hence the data used for the benchmarking was taken from different reports and did not always relate to the same year. Where possible we used actual rather than forecast data, although in two cases we relied on forecast data from the AER's most recent regulatory decisions.

Since the size of the networks in the different states differs, there is a need to normalise the performance for comparative purposes. For transmission networks the AER publishes an annual Electricity Performance Report for transmission service providers, which uses line length and capital base value as normalisers. These normalisers are also used for distribution networks. Another normaliser often used for distribution networks is the number of customers is also often used for distribution networks and for this review we have benchmarked against all three normalisers. We acknowledge that our analysis did not use a fully consistent data set and that this means that the results should be treated with caution. Nevertheless, we are confident that the benchmarking is sufficiently accurate to be indicative of the relative efficiency of the electricity network operation in all the states considered.

The results of the benchmarking analysis are shown in Table 10.2. It can be seen that Western Power does not benchmark well against its capital base and it is near the top of the band for other normalisers. We think that the poor performance against its capital base could indicate that Western Power's asset base is, on average, older than in the other states. This would be consistent with the reported low level of asset renewal on the distribution network, which accounts for about 60% of the capital base, in the early years of the last decade. However, Western Power's comparative performance against the other benchmarks is not impressive and does indicate that efficiency gains should be possible.

Table 10.2: Network Benchmarking Results

	Opex/km line ($ real, 2012)	**Opex/Customer ($ real, 2012)**	**Opex/Capital base**
Western Power	4,507	433	7.2%
Queensland	4,053	436	4.2%
New South Wales	4,814	409	6.0%
Victoria	3,900	248	6.1%
South Australia	2,724	309	5.7%
Tasmania	3,965	407	5.0%

Source: GBA analysis. The data used as input for this analysis was taken from the following AER reports: *TNSP Electricity Performance Report, 2008-09; State of the Market, 2011; Victorian Electricity DNSP Comparative Performance Report 2009; ACT and NSW Electricity DNSP Performance Report 2009-10; Queensland DNSP Final Decision (2010-11 to 2014-15) and South Australia Distribution Final Decision (2010-11 to 2014-15).*

Capturing these efficiency gains can take time and may require some investment. Therefore we think it more reasonable to capture these gains by incorporating an efficiency factor into the model rather than through a global adjustment to the base year expenditure. This will give Western Power a chance to adapt. Efficiency adjustments are discussed in Section 10.11.

10.3.1.3 Line Item Review

Our analysis of those opex line items to which Western Power has applied scale escalation indicates that, in aggregate in real terms, expenditure on these line items in the base year 2010-11 was 10.5% higher than opex in 2009-10. Even if allowance is made for some real cost increases that have not been adjusted for, this is nevertheless significantly higher than indicated by the change in the size of the network. In 2011-12 the opex on scale escalated line items is expected to increase by an even higher 15.6%, although this reduces to 10.3% after identified new expenditures are removed. Again, this increase seems high.

Western Power provided us with a detailed breakdown of its actual opex for 2009-10 and for the base year 2010-11. It has also provided a breakdown of its expected opex for 2011-12, which it prepared following an internal review of its actual opex during the first quarter[48]. Given the significant escalation in the expenditure during AA2, we reviewed Western Power's expenditure breakdown to identify base year expenditure line items that appeared to be atypical focusing in particular on line items where the increase from 2009-10 was particularly large and sought further information from Western Power on the reasons for the increase. These individual line items are discussed below.

10.3.1.3.1 Distribution Corrective Deferred – Emergency Follow-up Overhead Maintenance

Actual and expected AA2 expenditure on this line item is shown in Table 10.3.

Table 10.3: AA2 Expenditure on Distribution Corrective Deferred Emergency Follow-up Overhead Maintenance ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
3.8	8.4	4.1	120%

Source: Western Power

Western Power commented that:

> *The recorded spend for this program in 2006/07 and 2007/08 was in line with our 2010/11 base year, at $7.58 million and $7.26 million respectively.*
>
> *In 2009/10 we identified a significant increase in corrective emergency expenditure and corresponding decrease in corrective deferred expenditure during 2008/09 and 2009/10 which triggered an investigation. Consequently, we identified an anomaly in the cost capture mechanism which led to field staff incorrectly booking deferred work to the [corrective] emergency category.*
>
> *This was rectified in 2009/10 and from 2010/11 costs have been correctly recorded against this category increasing the expenditure to $8.37 million.*
>
> *The current, year to date (up to 30th Nov 2011) expenditure for 2011/12 is tracking similarly to 2010/11 (and indeed 2007/08 and 2008/09) and therefore the F1 forecast has been identified as being insufficient. The forecast for F2 is expected to be at a similar value as 2010/11.*

The argument is that the 2009-10 level is abnormally low due to an unexplained anomaly in the cost capture mechanism leading to time being incorrectly booked. Hence we would expect that this would be offset by a rise in the "Corrective Emergency" cost category. As shown in Table 10.4, this is indeed the case. Actual total expenditure for both the

[48] This is the best available estimate of the probable opex in the current year. The information in the AA3 access arrangement information was taken from Western Power's 2011-12 work plan, as approved in January 2011.

corrective deferred and corrective emergency maintenance reduced from $99.6 million in 2009-10 to $98.9 million in $2010-11.

Table 10.4: Efficient Opex Analysis for Corrective Deferred and Corrective Emergency Maintenance ($ million, real 2011-12)

	2009-10	2010-11
Corrective Deferred (Actual)	20.6	28.0
Corrective Emergency (Actual)	79.0	70.9
Total (Actual)	99.6	98.9
Estimated Indirect Cost Component of Total (14%)[1]	13.9	13.8
Estimated Total Direct Costs (Actual)	85.7	85.1
Efficient Cost (2.00% escalation)[2]	85.7	87.4

Source: Western Power and GBA.
Note 1: This estimate is based on information provided by Western Power on the cost component of its actual and forecast opex.
Note 2: See Table 10.13.

In its scale escalation model, Western Power has added a one-off recurring adjustment of $3.0 million (excluding indirect cost allocation) in 2011-12 to the "Distribution Corrective Emergency" category to offset the low actual cost in 2010-11. The analysis in Table 10.4 considers the validity of this adjustment on the basis that the cost recorded for this line item in 2009-10 is high and that the cost allocation in 2009-10 between "Distribution Corrective Deferred" and "Distribution Corrective Emergency" was suspect. We assume that the total cost for the two line items for 2009-10 ($99.6 million) is efficient, given that we have no information to suggest otherwise.

The analysis presented in Table 10.4 strips this cost of its estimated indirect cost component and then escalates the resulting direct cost by our estimate of a reasonable network growth escalation rate to determine an efficient level of total direct costs for both line items in 2010-11. As can be seen from the shaded cells in Table 10.4, an upward adjustment of +$2.3 million (rather than the $3.0 million assumed by Western Power) in base year direct cost is indicated.

We investigated anomalies in the 2010-11 expenditure on the "pole-vehicle interaction" and "emergency follow-up asset replacement line items" within the "distribution corrective deferred" category and found these anomalies were also due to the cost allocation problem. These anomalies would also be addressed by the +$2.3 million adjustment, which was calculated at an expenditure category level.

10.3.1.3.2 Distribution Corrective Deferred – Data Correction

Actual and expected AA2 expenditure on this line item is shown in Table 10.5.

Table 10.5: AA2 Expenditure on Distribution Data Correction ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
0.9	3.3	1.1	267%

Source: Western Power

Western Power commented that:

> *Western Power undertakes an ongoing data correction program of work to assess and rectify data related to our assets. Historically this business as usual activity has cost around $1.0 million per annum.*
>
> *In 2010/11, Western Power identified a number of programs which had been affected by poor data quality. Subsequently, we introduced special projects to address these data issues. The project completed in 2010/11 was data correction*

on inconsistencies associated with our bushfire mitigation program of work. This cost $2.36 million.

We have forecast an ongoing program of special data correction activities to ensure the efficiency of our investment, with our asset strategies heavily dependent on correct data. In AA3, we will be targeting assets such as switch-wires, conductors and underground assets. While these projects are related to different assets than 2010/11, the type of work will not change, and therefore the expenditure in 2010/11 is representative of the level of expenditure we expect to require in the AA3 period.

The AA3 expenditure forecast for this activity is consistent with our response in GB26 in relation to data improvement activities and is part of our strategy to further improve data quality.

The bush fire mitigation data correction project appears to be a one-off project and this is consistent with the reduced cost of this program in 2011-12. We see no basis for treating this one-off cost as a recurring expenditure throughout AA3, particularly at the same time as Western Power will be undertaking the comprehensive network wide field survey data capture project discussed in Section 10.6.2.1.

We propose that, for scale escalation modelling, the base year 2010-11 opex include only the business as usual component of this item. This implies a downward adjustment of $2.3 million. Should Western Power wish to incorporate additional opex for data cleansing programs during AA3, this should be submitted, with appropriate justification, as non-recurring expenditure. This could then be considered on its merits prior to the release of the final decision.

10.3.1.3.3 Distribution Preventive Condition – Earthing Maintenance

Actual and expected AA2 expenditure on this line item is shown in Table 10.6.

Table 10.6: AA2 Expenditure on Distribution Data Earthing Maintenance ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
1.3	2.3	1.7	79%

Source: Western Power

Western Power commented that:

This activity is targeting the prioritised rectification of the 17,000 currently identified earthing issues that exist upon the distribution network. Around 8,000 of these conditions are related to pole top switch disconnectors. In 2002, EnergySafety advised Western Power of the need to address the increasing number of pole top switch disconnector earthing hazards.

There are approximately 3,000 new earthing defects identified each year, with around 1,000 of these able to be addressed. As a result of an increasing number of conditions identified, there has been a steady increase in the expenditure required to ensure the safety risk is minimised.

As a result of rate of identification growing increasingly faster than the rate of correction, historical levels of expenditure (prior to 2009/10) have not been adequate. The level of expenditure in 2010/11 reflects a program of work designed to address the safety risk more effectively and is expected to continue through the AA3 period.

The quality of earthing is an ongoing issue for distribution network operators. It is a particular problem on older networks where earthing was not installed to the standard now required. While the consequence of poor earthing can be serious and sometimes fatal, the actual risk posed by an individual problem will be a combination of the severity of the problem and the likelihood of somebody being in the wrong place at the wrong time. Hence, addressing earthing problems is a risk management issue with the highest risks given priority.

The decline in expenditure between 2010-11 and 2011-12 indicates that there is no pressing need for expenditure to continue at the level actually incurred in 2010-11 through to the end of AA3. We propose reducing the base year expenditure on this line item from $2.3 million to the 2011-12 level of $1.7 million, an adjustment of -$0.6 million. This level of expenditure is still more than 30% higher than the actual expenditure in 2009-10, which Western Power has indicated was in turn higher than earlier years.

10.3.1.3.4 Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency ($ million, real 2011-12)

Actual and expected AA2 expenditure on these line items is shown in Table 10.7.

Table 10.7: AA2 Expenditure on Emergency and Corrective Transmission Substation Primary Plant Maintenance ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
4.6	7.1	6.1	54%

Source: Western Power

Western Power commented that:

> *Based on our actual spend for 2011/12 (to 30th Nov 2011) in these activities, it is expected that 2011/12 will be in line with, if not higher than 2010/11 expenditure and is expected to increase in F2.*
>
> *Furthermore, it should be noted, [that]… expenditure in corrective deferred and corrective emergency is un-planned and therefore not predictable or able to be trended over time at the individual activity level (i.e. primary plant).*
>
> *In order to provide meaningful analysis, these categories of expenditure (i.e. transmission corrective deferred and transmission corrective emergency) should be considered as a whole, rather than at the asset category level.*
>
> *The level of expenditure in the corrective deferred and corrective emergency categories is expected to continue given the increase in the size of the network and the aging asset population.*

We agree with Western Power that corrective and emergency maintenance is unpredictable but do not agree that that it cannot be trended over time. We would expect unpredictable expenditure to be volatile from year to year but this volatility would be around an average trend line, with some years being higher and some lower.

Where expenditure is volatile, it is not valid to use the highest expenditure over the previous regulatory period to form the base for a scale escalation model. To do so would be to imply that the forecast expenditure requirement would be an upper bound, rather than the expected overall expenditure over the regulatory period. We therefore propose to adjust the base expenditure to the average annual expenditures in these categories over the period, which translates to $5.9 million. This is a downward adjustment of -$1.2 million, which we have applied to the "corrective emergency" category[49].

10.3.1.3.5 Transmission Corrective Deferred – Environmental Cleanup

Actual and expected AA2 expenditure on these line items is shown in Table 10.8.

[49] Applying the adjustment to the "corrective deferred" or "corrective emergency" categories will make no difference to the model output.

Table 10.8: AA2 Expenditure on Transmission Environmental Cleanup ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
0.3	1.2	0.9	308%

Source: Western Power

Western Power commented that:

> *In 2010/11 we completed a large number of cleanup works to dispose of PCB on Western Power sites. Prior to 1975 PCB was used widely as insulation in electrical capacitors and transformers. Since then it has been discovered PCB is an environmentally hazardous substance and when released it does not readily break down and may remain active in the environment indefinitely.*
>
> *Equipment is routinely tested for PCB when decommissioned and if found positive, is required to be disposed of in accordance with environmental legislation. The significant investment in the transmission network during the 1960-70s means that numerous substation plant assets are suspected of containing PCB. Therefore, the level of PCB disposal experienced in 2010/11 is expected to continue throughout AA3 due to the increased number of older plant assets reaching the end of operational life.*

We are surprised that Western Power still needs to fund PCB disposal. In New Zealand, as in many jurisdictions, PCB was considered such a serious environmental hazard that in the late 1980s and throughout the 1990s PCB contaminated equipment was required to proactively identified and either decontaminated or disposed of, in order to reduce the risk of accidental leakage. In many jurisdictions this program is now complete.

The reduction in expenditure in 2011-12 indicates that expenditure on this line item is volatile. Hence, as discussed in the above section, the base year opex should be the average annual AA2 expenditure, rather than the maximum. We therefore propose an adjustment of -$0.4 million, to reduce the base year expenditure on this line item to the average annual expenditure over AA2.

10.3.1.3.6 Transmission Preventative Condition – Plant and Building Refurbishment

Actual and expected AA2 expenditure on these line items is shown in Table 10.9.

Table 10.9: AA2 Expenditure on Transmission Plant and Building Refurbishment ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
0.3	1.4	0.9	417%

Source: Western Power

Western Power commented that:

> *This activity relates primarily to the refurbishment and modification of existing older "in service assets" to support the deferral of capital expenditure for asset replacement works.*
>
> *The use of costly modified and refurbished substation plant and equipment will continue as there remains a large population of critical assets that require maintenance. Therefore, expenditure in this category is expected to continue to increase from the 2010/11 position.*

Expenditure on plant and building maintenance is largely predictable. Expenditure in 2011-12 is expected to reduce significantly from the level incurred in 2010-11 and Western Power has provided no convincing reason why the high level of expenditure incurred in 2010-11 needs to be carried through to AA3. We therefore propose an adjustment of -$0.5 million, to reduce the base year expenditure on this line item to the average annual expenditure over AA2.

10.3.1.3.7 Substation Battery Maintenance and Inspections

Actual and expected AA2 expenditure on these line items is shown in Table 10.10.

Table 10.10: AA2 Expenditure on Substation Battery Maintenance and Inspections ($ million, real 2011-12)

2009-10	2010-11	2011-12	Increase 2010-11
1.4	1.7	0.6	21%

Western Power commented that:

> *The inspection of batteries in substations is completed by the work crew as part of the transmission substation inspection (booked to K1X6), with the maintenance of batteries being undertaken by a different crew at a later time. Prior to 2011/12, field staff completing transmission substation inspections were estimating the time taken to inspect substation batteries and allocating this time to the substation battery maintenance and inspections activity. For improved cost and asset management, at the start of 2011/12 the inspection component of substation battery maintenance and inspections (K1X3) was moved to transmission substation inspections (K1X6).*
>
> *The combined total of the two categories is in line with the historical trend.*

In order to test Western Power's argument that the combined total is in line with historic trends, we have aggregated the preventive routine maintenance line items for "substation primary plant" and "battery maintenance and inspections". This aggregation is shown in Table 10.11.

Table 10.11: Aggregated AA2 Expenditure on Substation Routine Maintenance ($ million, real 2011-12)

	2009-10	2010-11	2011-12	Increase 2010-11
Battery Maintenance and Inspections	1.4	1.7	0.6	21%
Substation Primary Plant	3.3	4.6	4.9	38%
Total	**4.7**	**6.3**	**5.5**	**33%**

Table 10.11 indicates that the base year 2010-11 opex is still high compared with either of the other two years. We therefore propose an adjustment of -$0.8 million, to reduce the base year expenditure on these line items to the average annual expenditure over AA2. This adjustment will be applied to the Transmission Preventive Routine maintenance line item.

10.4 SCALE ESCALATION MODEL INPUTS

10.4.1 Scale Escalators

The principle underpinning the scale escalation approach to opex forecasting is that real increases in opex are driven by growth in the size of the network and also by the number of connected consumers. For scale escalation purposes, the AER measures the size of a distribution network by zone substation transformer capacity, line length and the number of distribution transformers, with each factor being equally weighted. The size of a transmission network is measured by the value of its capital base.

Western Power has used the AER measure of distribution network size[50] as the basis for determining the scale escalator and applies this to its whole network, including the transmission component. We considered whether it is appropriate to apply an escalator designed for a distribution network as a basis for forecasting the opex requirement of transmission assets and concluded that, for Western Power, any error is unlikely to be material. This view is based on the following considerations.

- Subtransmission assets are classified as transmission by Western Power whereas in other jurisdictions they are classified as distribution. Hence, distribution assets form only 58% of Western Power's capital base, whereas in Queensland, New South Wales and Victoria they form between 75% and 80% of the total network capital base within each state.

- The distribution measure of network size focuses on the quantity of network assets rather than their value and is therefore a better measure of the opex driver. The use of capital base as a measure of the size of the asset base gives new assets an unduly high weighting, when in reality these assets should require less maintenance.

Western Power based the escalators used in its model on its forecast customer numbers, line length, number of distribution transformers and zone substation transformer capacity. While forecast customer numbers were taken from an independent report, no information was provided on the basis for its forecast of network asset quantities. Hence, in order to assist us evaluate the reasonableness of its forecasts, we requested information from Western Power on historic growth rates and compared them with the forecast level. This is an approach that the AER has used to evaluate the reasonableness of the proposed escalators. The relevant information is shown in Table 10.12.

Table 10.12: Growth Escalation Data

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

Source: Western Power

It can be seen from Table 10.12 that in its scale escalation opex model, Western Power has used a significantly higher network growth escalator than indicated by recent historical growth rates because of significantly higher forecast growth rates in the number of distribution transformers and zone substation transformer capacity. Growth rates for line length and customer numbers are comparable with historic growth.

We see no basis for the acceleration in the annual rate of increase in the number of distribution transformers. The number of transformers on a distribution network is driven largely by the number of customers and, to a lesser extent, by the growth in distribution line length. Western Power considers forecasts of the rate of growth of both drivers to be similar to historic levels and has provided no explanation for a significant increase in the numbers of installed transformers.

50 On p135 of the AAI, Western Power stated that the number of feeders rather than the number of distribution transformers form an input to the scale escalator. However, the numbers used to calculate the escalator were not consistent with the expected number of feeders and Western Power has confirmed that it actually used the number of distribution transformers in its analysis.

Western Power is also forecasting the installation of a total of 3,137 MVA new zone substation transformer capacity over the period 2010-17. We are unable to reconcile this with our analysis of the network development plan, which indicates the addition of only 1,236 MVA of new transformer capacity over the period, including the new substation transformer capacity proposed for the CBD.

We also note that Western Power used an average annual network growth escalation factor in its model, rather than the actual escalation factor for each year of the forecast period. This simplifying assumption assumes that assets are added to the network at a constant rate. However this is not the case – Table 7.1 shows that Western Power's forecast average annual transmission capex for the first three years of AA3 is $276.6 million whereas in the last two years it is $394.0 million. This disparity is also reflected in the escalation factors derived from Western Power's forecast asset quantities – these indicate an escalation factor of 2.1% in 2011-12, 4.8% in 2015-16 and 4.1% in 2016-17. Because the addition of new assets is biased toward the end of the period, Western Power's simplifying assumption of a constant growth rate overstates the opex requirement by a material amount. Our analysis, using the numbers in the model provided by Western Power, indicates an opex impact due to the effect of network growth escalation of $176.6 million (real, 2012) under a constant growth assumption compared to only $152.6 million, if actual escalation rates are used, a difference of $24 million or 16%. This is because the constant growth rate assumption assumes the maintenance of non-existent assets in the early years of the period, and the effect of this is compounded in later years[51].

Another factor relevant to the determination of an appropriate escalation factor for forecasting growth in recurring opex is the capex-opex trade-off. This trade-off arises because new assets require less maintenance than older assets, whereas a scale escalation approach implicitly assumes that all assets of a particular type require a similar level of maintenance, regardless of age. The AER allows recurring opex to be forecast using an escalation factor calculated on the basis of forecast asset growth but then applies a separate capex-opex trade-off factor to allow for a reduced level of maintenance on new assets. On the other hand, Nuttall Consulting Ltd, in a report for the AER[52], proposed that the two factors be combined by using historic growth rates over the previous regulatory period as the basis for determining the escalation factor. The rationale for Nuttall's approach is that there is a honeymoon period after new assets are installed where little maintenance is required. Hence there is a lag between when assets are installed and when they must be inspected or maintained. In other words the additional maintenance effort is caused not by the assets that are currently being installed but by the new assets that were installed during the previous regulatory period.

While we consider Nuttall's approach pragmatic, we believe his logic is sound. Consistent with Nuttall's proposed approach, we suggest that Western Power's relevant base year opex components be escalated by a network growth escalator of 2.10%, rather than the 3.42% used in Western Power's proposal and also suggest that no capex-opex trade-off factor be applied[53]. As shown in Table 10.12, the 2.1% represents the actual network growth over the period 2007-11. We note that, using this approach, it is not necessary to propose more accurate forecast growth rates or to adjust the opex forecast for the impact of any difference between the AA3 capex forecast by Western Power and that allowed by the Authority.

10.4.2 Economy of Scale

In its regulatory decisions the AER has required provision for economy of scale (EOS) to be incorporated into opex forecasts undertaken using a scale escalation approach. However Western Power has made no such provision in its modelling.

51 We are not suggesting this situation would arise in all scenarios and acknowledge that in situations where capex early in the period was higher, a constant growth rate assumption could underestimate the opex requirement. Nevertheless, the error introduced by using the simplifying assumption can be large, as is the case here.

52 *Memo – Opex Escalation Review (Victoria Electricity Distribution Revenue Review):* Nuttall Consulting, 28 October 2010. This memo is available on the AER's web site.

53 Western Power has not used a capex-opex trade off factor in its opex forecasting model.

Essentially, EOS arises because opex is an aggregate of a fixed cost component and a variable cost component. As the network increases in size variable costs will increase but fixed costs will remain unchanged. An EOS factor will therefore vary between 0 and 1 depending on the ratio of fixed to variable costs for a particular line item. In theory, a line item comprised only of fixed costs will have an EOS factor of 0, while a line item comprising only variable costs will have an EOS factor of 1. In practice the EOS factor will lie between these two extremes depending of the extent to which the costs of a particular line item are fixed. By not including an EOS factor in its scale escalators, Western Power has implicitly assumed that its opex costs are fully variable, an assumption that we do not accept.

In its recent revenue application, Powerlink proposed EOS multipliers of 40% for direct network operating cost and 95% for the direct cost of network maintenance activities[54]. Similarly in its application ETSA Utilities used multipliers of 95% for direct maintenance costs and 25% for direct network operating costs. ETSA Utilities also used a multiplier of 95% for activities involving direct customer interaction[55]. These EOS multipliers were generally accepted by the AER.

However, the recent Victorian distribution decision investigated the determination of an appropriate EOS multiplier in greater detail and the AER's final decision came up with much more aggressive multipliers, particularly for maintenance costs. In this decision the AER applied overall EOS multipliers 35% and 50%. While the reason for this difference is not entirely clear since we do not have access to the model used by the AER, we think the multipliers were applied to both the direct and indirect cost components of a particular line item. However it seems that both Powerlink and ETSA Utilities applied the EOS multiplier to direct costs only, which is the approach taken by Western Power in its scale escalation model. We would expect the EOS multiplier to be higher when scale escalation is only applied to direct costs as we would expect the fixed cost component of indirect and corporate costs to be higher.

This is reflected in the Western Power forecast. While scale escalation increases the direct operating and maintenance costs to which it is applied by 3.3% per year over the period 2012-17, the total forecast opex (excluding real cost escalation) increases by only 2.5% per year. This is still significantly higher than the net growth rates[56] of between 0.3% and 0.9% allowed by the AER in the Victorian decision.

A final issue to be considered is the direct cost EOS multiplier to use for network operations. As noted above the AER accepted an operations multiplier of 40% for Powerlink and 25% for ETSA Utilities. In our view the rationale for having different operating EOS multiplies for transmission and distribution assets is sound. Transmission assets require active operation whereas many assets incorporated into the composite networks growth indicator used for escalation purposes, including low voltage lines, distribution voltage spur lines, and distribution transformers have little impact on a distribution network's operating costs. Given that Western Power operates an integrated network, but recognising that the distribution network comprises the larger portion of the asset base, an operations EOS multiplier of 30% seems appropriate.

10.4.3 Proposed Net Growth Escalators

Given the considerations in the above sections, we suggest the following direct opex scale escalators shown in Table 10.13 are reasonable. We have assumed these escalators in the opex model we used to prepare our estimate of Western Power's efficient AA3 opex. While Western Power classifies "Reliability" and "SCADA and Communications" activities as network operations, we have treated them as maintenance for scale escalation purposes in recognition of the significant maintenance component within these activities.

54 *2013-17 Powerlink Queensland Revenue Proposal:* Table 9.4, p92.

55 *ETA Utilities Regulatory Proposal, 2010-15*: Table 7.39, p 174; Table 7.41, p175. Note that in this table the EOS factor is presents in the form of (1-EOS multiplier), using the EOS multiplier as applied in this report.

56 See Table 7.16 (p352) of the AER's final decision for the Victorian distribution service provider. Net growth rates are the growth escalator modified by the EOS multiplier. They are applied before taking real cost escalation into account.

Table 10.13: Proposed Scale Escalators (% per annum)

	Growth	EOS	Capex-Opex	Net Growth
Distribution				
Network Operations	2.10	30	100	0.63
Reliability	2.10	95	100	2.00
SCADA and Communications	2.10	95	100	2.00
Maintenance - Corrective Deferred	2.10	95	100	2.00
Maintenance - Corrective Emergency	2.10	95	100	2.00
Maintenance - Preventive Condition	2.10	95	100	2.00
Maintenance - Preventive Routine	2.10	95	100	2.00
Call Centre	2.41	95	100	2.33
Metering	2.41	95	100	2.33
Transmission				
Network Operations	2.10	30	100	0.63
SCADA and Communications	2.10	95	100	2.00
Maintenance - Corrective Deferred	2.10	95	100	2.00
Maintenance - Corrective Emergency	2.10	95	100	2.00
Maintenance - Preventive Condition	2.10	95	100	2.00
Maintenance - Preventive Routine	2.10	95	100	2.00

Source: GBA.

10.4.4 Step Change Adjustments

Step change adjustments are applied where recurrent opex forecast by scale escalation of Western Power's base year expenditure is not a true reflection of the recurrent opex requirement. This would occur in the following situations:

- Western Power expects to incur a new opex cost after the base year. An example would be a cost incurred as a result of an anticipated new legal or regulatory requirement;

- It is anticipated that a recurrent cost incurred in the base year will not be required at some later point; or

- A component of the base year cost is atypical in that it is, for some reason, higher or lower than Western Power would expect to spend in a normal year.

Western Power has incorporated the following step change adjustments in its model.

- A step change of +$0.8million from 2011-12 for expenditure associated with additional SCADA and communications infrastructure added to the existing network. We accept this and in our model have adjusted the base year opex to include this expenditure.

- A step change of +$1.0 million from 2012-13 to accommodate the new Clarity/Oracle licences and support contract after completion of the project in 2009/10. This appears to be related to the above step change; we assume that the first two years licensing and support was included in the purchase contract and capitalised. We have allowed for this in our model, but have treated it as a one-off adjustment that occurs in each year of the regulatory period, since software licences are a fixed cost not subject to scale escalation.

- A step change of +$0.5 million from 2011-12 to increase the number of metering verifications and compliance testing expected from the planned changes to the

Electricity Industry Metering Code 2005 (Metering Code) due to be gazetted in December 2011. This change will make it mandatory for Western Power to undertake a meter reading of all installations every 12 months. We note that this change was included in the Office of Energy's Final Recommendations Report but at the time of writing this report the amendments to the Metering Code still had to be drafted and gazetted. This would indicate that the additional cost will not commence until 2012-13.

- A step change of +$3.0 million from 2011-12 to ensure a sustainable level of corrective works. Western Power considers that 2010-11 was not a typical year for corrective works as there was a 20% lower than expected level of faults on the network, which is not expected to continue. This adjustment is discussed in Section 10.3.1.3.1 and, based on the analysis presented in Table 10.4, we have replaced this adjustment with an upward adjustment of +$2.3 million to the "Distribution Corrective Emergency" base year cost.

- A step change of -$0.3 million from 2011-12 to reflect efficiencies gained by bundling fuse pole clearing with vegetation inspections and anticipated savings through the fire safe fuses programme. We accept this and in our model have adjusted the base year opex to include this adjustment.

10.4.5 One-off Adjustments

One-off adjustments are special non-recurring adjustments to recurring opex line items. Being non-recurring adjustments they are not subject to scale escalation. The only one-off adjustment proposed by Western Power relates to the inclusion of +$5.2 million in 2011-12 and +$8.7 million per year over the three year period 2012-15 for transmission line pole inspection and maintenance, which we understand relates to additional work required as a result of the EnergySafety Order. We consider these adjustments reasonable.

10.5 SCALE ESCALATION MODELLING ISSUES

We have reviewed Western Power's scale escalation model and note the following:

- Western Power has advised that shortly after submission of the AA3 access arrangement information, an error was found in the scale escalation model. This related to the inflation factor used to convert the 2010/11 actual expenditure used as the basis for the scale escalation calculations into 2011/12 real dollars. This should be corrected.

  The impact of this error is that the opex forecast in the AA3 access arrangement information is understated by about $3 million, before the application of indirect costs and real cost escalation. We have used the correct inflation factor in our model.

- Where a new recurring expenditure first occurs after the base year, Western Power has applied growth escalation in full from the base year (even though expenditure in prior years is not modelled). We think there should be no growth escalation in the first year the expenditure occurs and that growth escalation should only be applied in subsequent years.

  However, we noted that Western Power treated what were, in reality, base year adjustments as new recurring expenditure starting in 2011/12. In this situation we think Western Power's growth escalation treatment was appropriate. For consistency, in our model we have treated such expenditure as a base year adjustment and note that this changed treatment has no impact on the modelling result.

- There appears to be an error in the treatment of one-off expenditures in Western Power's escalation model. The model escalates the total line item expenditure for the previous year, including one-offs. Then, to adjust for the one-offs, the current year's one-offs are added and the previous year's removed, with neither amount escalated. Hence the escalation of the previous year's one-off expenditure remains in the model and is not adjusted out. This impact of this error is compounded in later years.

Adjustments for the new recurring expenditure issue and the treatment of one-off expenditures will both reduce the opex as forecast by Western Power model. Given the inputs used by Western Power, the impact of an adjustment for new recurring expenditure will be small since the only truly new cost is the $0.8 million for SCADA opex. Western Power's other recurring expenditure adjustments are essentially adjustments to the base year amount.

The one-off expenditure adjustments relate primarily to pole inspections and are significantly larger. Hence the impact of the escalation error in the treatment of these expenditures is material.

10.6 OTHER DISTRIBUTION OPEX

10.6.1 Smart Grid

Actual and expected AA2 expenditure on this program is shown in Table 10.14.

Table 10.14: Forecast AA3 Opex on Smart Grid ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
4.3	3.5	4.2	5.5	6.7	24.3

Source: Western Power

This opex is discussed in Appendix B7. As noted in Section 8.9, this is a high risk program in that there is no net benefit to Western Power. It is justified only by wider societal benefits that, while quantified by Western Power, are nevertheless speculative. However, if the program is to proceed, then we consider the AA3 opex forecast is reasonable.

10.6.2 Non Recurring Opex

10.6.2.1 Field Survey Data Capture Project

Forecast AA3 expenditure on this program is shown in Table 10.15.

Table 10.15: Forecast AA3 Expenditure on Field Survey Data Capture ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
5.6	7.2	7.2	7.1	7.2	34.3

Source: Western Power

This project is discussed in detail in Appendix B5. The cost is substantial and it appears to be the most expensive and comprehensive project of its kind undertaken by any electricity distribution business in Australia.

Our review of the information initially provided by Western Power led us to believe that benefits of the project were overstated and that the need for the project was largely of Western Power's own making. However, additional information, in particular the business case for the pilot project on which the proposed project is based, has caused us to modify that view in that we now accept that the poor quality of asset data is largely a legacy issue for which the current management cannot fully be held responsible. Nevertheless, Western Power's ongoing failure to recognise the importance of updating asset data to reflect the current state of the network has contributed in no small way to the quality of asset data deteriorating to its current state. Even now, asset data discrepancies that require a field check to resolve are ignored.

It appears that this project has largely been formulated in response to EnergySafety and other stakeholder concerns about the quality and efficiency of Western Power's wood pole management processes and the management of other issues relating to the risk of Western Power's distribution network assets initiating bush fires in high risk areas. However, our review of the documentation on these issues that has been made available to us indicates that the timeliness and accuracy with which asset inspection and maintenance records are uploaded into Western Power's asset management database is a much more serious problem than the state of the underlying database recording the existence of assets in the field.

Given this, and having regard to the results of our more detailed analysis presented in Appendix B5, we are unconvinced that the quality of the existing data set has deteriorated to the extent that the most extensive project of its kind ever undertaken in Australia is now required. We think an approach that targets areas where the data is known to be poor, and relies on field checks to resolve discrepancies in areas, such as Perth metropolitan, where data quality is known to be relatively good, may meet Western Power's requirements and be much less costly. Such an alternative should be given more serious consideration.

For the purposes of the draft decision we propose that the opex requirement proposed by Western Power be reduced by 50%. Should Western Power consider this amount insufficient, it could provide additional information following the draft decision for further consideration by the Authority.

10.6.2.2 Network Control Expenditure

Forecast AA3 expenditure on this line item is shown in Table 10.16.

Table 10.16: Forecast AA3 Expenditure on Distribution Network Control Services ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
2.3	2.3	2.3	2.3	2.4	11.7

Source: Western Power

The areas targeted for network control services on the distribution network in AA3 include Ravensthorpe and Bremer Bay. The least cost option to alleviate network constraints in these areas is provided by peak lopping to a small islanded network supplied via power stations at each town.

The use of network control services in the form of embedded generation can be a cost effective way of deferring the need for expensive and potentially uneconomic network capital upgrades. The future requirement for network control service is difficult to forecast as actual expenditure will depend on electricity usage in the area of interest. Given this, we have not reviewed Western Power's forecast requirement in detail, even though it is larger than the actual expenditure in AA2. We propose that it be accepted without modification.

10.6.3 Distribution Quotations

Forecast AA3 expenditure on this line item is shown in Table 10.17.

Table 10.17: Forecast AA3 Expenditure on Distribution Network Control ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
4.1	4.2	4.3	4.3	4.3	21.2

Source: Western Power

The demand for distribution quotations is customer driven and thus largely outside the control of Western Power. Hence it is difficult for forecast. Western Power's forecast

AA3 requirement is lower than the average actual expenditure during AA2 and we propose that it be accepted without modification.

10.6.4 GSL Payments

Forecast AA3 expenditure for GSL payments is shown in Table 10.18.

Table 10.18: Forecast AA3 Expenditure on GSL Payments ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
2.5	2.9	3.2	3.5	3.8	15.9

Source: Western Power

Expenditure for GSL payments is made up of the following two components:

Planned outage non-notification payments

Part 3 of the Supply Code requires Western Power to make a payment to customers of $20, on application by the customer, in situations where the notice of a planned outage is given less than 72 hours of the outage occurring. Western Power chooses to pay $50 as a strategy for holding Western Power to account for this measure.

Given that the provision of notices of planned outages is fully within the control of management we do not think this cost should be passed through to customers, particularly when the amount of each payment is over and above the amount Western Power is legally obliged to make.

Extended outage payments scheme

However, the bulk of the payments within this line item are made under the extended outage payments scheme (EOPS). Section 19 of the Supply Code requires a payment of $80 to be made, on application, to customers who are without supply for more than 12 hours as a result of a planned or unplanned interruption.

The number of customers eligible for payments under the EOPS has increased from 18,228 in 2006-07 to 64,208 in 2010-11[57]. Western Power is forecasting that the number of customers eligible for EPOS payments will further increase to 180,521 by the end of AA3. This is in spite of Western Power introducing a new $41.4 million capex program in AA3 to address the causes of extended supply outages. This is separate to the accelerated pole replacement and targeted bushfire management programs, which we think will also address the causes of many extended outages. In these circumstances we suspect that an order of magnitude increase in the number of customers eligible for EPOS payments over an eleven year period would be unacceptable to many Western Power stakeholders.

A more reasonable target for Western Power in AA3 would be to maintain the number of customers eligible for EOPS payments at the 2010-11 level. As indicated in Appendix B1, this is consistent with the objective of the $41.4 million reliability compliance program designed to reduce the number of extended outages experienced by Western Power's worst served consumers. Furthermore the primary diver for extended outages is its practice of isolating and making safe fault locations for repair the next morning, where faults occur in the late afternoon or at night. A more proactive approach to the after-hours repair of faults, in line with that practised by other network service providers, would also be a good starting point for a program aimed at reducing the number of outages liable for EOPS payments.

EPOS payments are only available on customer application. Hence the amount actually required to be paid will depend on the application rate, which varied from 11% to 37%

57 This does not include the 124,875 eligible customers in 2009-10, which was a result of a severe storm on 22 March 2010.

over the five year period 2006-11. Western Power has noted that application rates have increased in recent years as a result of publicity over the payments. We think an average application rate of 30% over AA3 is possible.

Storm events, such as occurred in March 2010 will also impact the required payment level. These cannot be controlled by Western Power and its ability to mitigate the impact of severe storms is limited. We therefore suggest a provision of 10% over and above the target payment level be included to fund additional payments for storms.

On this basis our proposed annual opex requirement for GSL payments is shown in Table 10.19.

Table 10.19: AA3 Proposed Annual GSL Opex

No of affected customers	64,208
Claim rate	30%
Individual payment rate	$80
Target opex requirement	$1.55 million
Storm provision (10% of target opex requirement)	$0.15 million
Total annual opex requirement	**$1.70 million**

Source: GBA

This forecast is not subject to inflation or real cost escalation.

10.7 OTHER TRANSMISSION OPEX

10.7.1 Network Control Services

Western Power's forecast AA3 expenditure for network control services (NCS) is shown in Table 10.20.

Table 10.20: Forecast AA3 Expenditure on Network Control Services ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
10.8	4.5	9.4	12.1	17.7	54.5

Source: Western Power

Network control services are payments made to contracted generators in selected areas to operate at times of peak demand. If generators can be contracted in network constrained areas, then expensive network augmentations can be deferred providing economic benefits to stakeholders.

During AA3 Western Power envisages that provision of network control services will be economically justified in Albany, Geraldton, the Eastern Goldfields and Pinjar. It will be noted that (except for Pinjar where the NCS will allow the construction of a new 330 kV terminal station to be deferred) these are fringe network locations located several hundred kilometres from the core grid.

Western Power has provided a confidential paper on how it calculated its forecast AA3 network control services opex requirement. We have reviewed this paper at a high level and note that the forecast amount represents the difference between the costs that an NCS provider would recover from the Independent Market Operator and the actual cost of diesel generation – in effect the difference between the cost of generation using open cycle gas turbines and that using reciprocating diesel engines. We have not verified the generation cost assumptions nor reviewed in detail the assumptions made in respect of the need for NCS services. However, a high level reading of the paper indicates these assumptions are most likely reasonable and did not raise any cause for concern.

The uncertainties involved in forecasting this line item are much higher than most other opex line items. Generation costs will depend heavily on the cost of oil and the actual requirement for NCS services will depend on the actual demand for electricity.

Given this high level of forecasting uncertainty, and the fact that NCS costs are incurred in lieu of capex, it is not clear to us that it is appropriate to provide for NCS as part of the regulated revenue cap. In its paper, Western Power noted that under clause 6.76 of the Access Code, it can recover non-capital costs that meet the efficiency test in the Code. The implication is clear that, should actual NCS costs exceed the forecast level, Western Power will apply for such recovery. However, if the forecast is included in the opex used to determine the regulated revenue cap, then under-expenditure against the forecast will be treated as an efficiency gain and not returned to customers. Indeed, under the gain sharing mechanism, the gain will be carried over into AA4. This would appear to create an asymmetry that strongly favours Western Power. To avoid this it may be better not to include NCS in the forecast AA3 opex but to require Western Power to recover all NCS costs using the provisions of clause 6.76 of the Access Code. We raise this matter for the Authority's consideration but make no firm recommendation or proposal in this regard. We note, however, that these comments are equally applicable to the distribution NCS discussed in Section 10.6.2.2.

10.7.2 Transmission Line Decommissioning and Removal

Western Power's forecast AA3 expenditure for transmission line demolition is shown in Table 10.21.

Table 10.21: Forecast AA3 Expenditure on Transmission Line Demolition ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
2.9	2.4	0.7	0.6	-	6.6

Source: Western Power

Western Power has advised that this cost represents the removal of approximately 60 km of overhead line, entailing approximately 400 structures plus a further 44 poles within substations, removal of obsolete cable sections and the removal of a small number of abandoned concrete and steel structures.

A breakdown of this cost estimate is shown in Table 10.22.

Table 10.22: Breakdown of Forecast AA3 Expenditure on Transmission Line Demolition ($ million, real 2011-12)

Asset Type	Cost
Approximately 444 structures at $10,000	4.44
Assume 20% of total structures require $6,000 per pole environmental remediation	0.48
Contaminated pole butt disposal at $500 each	0.15
Pilot cables, non wood pole redundant assets	0.70
Risk allowance	1.13
Total	**$6.90**[1]

Source: Western Power
Note 1: Unlike Table 10.21, this cost includes real cost escalation.

The cost of $10,000 per structure covers the removal of the pole, and its associated cross arms and conductors and is based on past experience. The risk allowance has been determined using risk assessments from similar historical projects and includes the risk of more structures requiring environmental remediation, removal of two pole structures costing greater than $10,000 per asset or disposal of contaminated materials.

The $10,000 cost per structure, while based on Western Power's past experience, is clearly a rounded number. It is reasonable to assume that this rounding has been up, rather than down. Given this, we were concerned at the inclusion of such a large risk provision in the estimate, since we believe costs based on past experience would normally be inclusive of risk, particularly when rounded up.

We benchmarked these forecast decommissioning costs against the cost previously provided to the Authority for the decommissioning and removal of the existing 132 kV line between Pinjar and Eneabba as part of the MWEP. This is a single circuit line, constructed like a cricket wicket with three poles per structure, which we understand to be approximately 190 km long. Western Power's A1 planning phase cost estimate for the demolition of this line is $5.53 million in June 2010 dollars or $6.01 million in June 2012 dollars. This cost is 10% less than Western Power's AA3 cost estimate for demolishing a third of this line length with fewer poles per structure. On this basis, it would seem that Western Power's AA3 opex estimate for transmission line demolition and removal is excessive.

We propose a revised estimate of $2.28 million in June 2012 dollars. We have derived this estimate by pro-rating Western Power's MWEP cost estimate and then adding a 20% margin to cover costs (such as project management and reduced economies of scale) that may not be adequately provided for in a simple pro rata analysis. Our proposed revised forecast, which we have derived by pro-rating the forecast in Table 10.21, is shown in Table 10.23.

Table 10.23: Proposed Forecast AA3 Expenditure on Transmission Line Demolition ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
0.9	0.8	0.2	0.2	-	2.1

Source: GBA

10.8 CORPORATE OPEX

10.8.1 Business Support Expenditure

Western Power's forecast AA3 opex for business support is shown in Table 10.24.

Table 10.24: Forecast AA3 Opex on Business Support ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
71.2	69.5	70.4	73.1	73.6	357.8

Source: Western Power

Business support opex is the cost of operating the various divisions within Western Power, which are required to support the business. These functions include corporate services, strategy and finance, regulation and sustainability, legal and governance and the office of the Chief Executive. It also includes the cost of the enterprise solutions division, which focuses on organisation wide strategic initiatives and long term business transformations.

Most, but not all, of these costs are fixed. The forecast in Table 10.24 is an average annual expenditure of $71.6 million, which is only 2.6% higher than the average annual AA2 expenditure of $69.7 million. On this basis, we accept that the AA3 forecast is reasonable, notwithstanding the magnitude of the expenditure in this line item.

10.8.2 Insurance

Western Power's forecast AA3 opex for insurance is shown in Table 10.25.

Table 10.25: Forecast AA3 Opex on Insurance ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
25.9	26.8	27.4	28.3	29.1	137.4

Source: Western Power

We asked Western Power for details of how it derived its insurance forecast and in particular whether external independent advice had been obtained. We also asked for an explanation for the 26% increase between the actual insurance costs in 2010-11 and the F1 expected opex in 2011-12. Understanding the reasons for this was important since the 2011-12 insurance costs appeared to be the basis for the AA3 forecast.

Western Power has advised that:

- The difference between 2010-11 and 2011-12 costs is primarily caused by two factors:
    - Workers compensation insurance costs were included in the 2011-12 insurance cost but not in 2010-11. This is an error as workers compensation is also included in the opex forecast as a payroll oncost and an adjustment is required to correct for this error, which is carried through to the 2011 forecast. This is shown in Table 10.26 below.
    - The actual insurance costs for 2010-11 includes one major bushfire during the year. The expected 2011-12 expenditure also allows for one major bushfire but also includes an additional self insurance cost in relation to a known bushfire in 2010.
- Western Power's forecast public liability premium during AA3 provides for an 11.5% increase per annum before the addition of the premium surcharge.
- It has made provision for self-insurance losses from one major bushfire loss each year to the value of $5.0 million. Western Power notes that bushfire incidents including Tooday (2007), Parkerville (2008), Yanchep (2009) and Balingup (2009) have each resulted in losses greater than $4 million. It expects that during AA3 major bushfire claims will be subject to a $5.0 million deductible.
- It has provided for self-insured minor losses to increase at the rate of 5% per annum (nominal).
- It has allowed for a 5% nominal annual increase in its property insurance premium rate based on a number of factors including historical losses, insurance market trends and global financial conditions in addition to an adjustment to the value of insured assets of 3.5%, based on Landgate valuations.

Western Power's forecast public liability and self-insurance costs were independently reviewed by QR Consulting. The report indicated, but did not explicitly state, that the forecast was reasonable given current market conditions. However the report also indicated that there is a lot of uncertainty in the insurance market and that changes to the current situation could have a negative effect on premium levels. Apart from the rise of 11.5% per annum in the base public liability insurance premium, Western Power's forecast makes no provision for such impacts.

While we are not experts in insurance, Western Power's forecast appears reasonable, after removal of the worker's compensation costs. It is clear from the information provided that the perceived risk of liabilities arising from major bushfire incidents is seen as very high and this is having a negative impact on Western Power's insurance costs.

The effect of the adjustment for the removal of worker's compensation costs is shown in Table 10.26.

Table 10.26: Revised Forecast AA3 Opex Insurance ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Original Forecast	25.9	26.8	27.4	28.3	29.1	137.4
Less Worker's Compensation	(3.0)	(3.2)	(3.4)	(3.3)	(3.2)	(16.1)
Revised Forecast	22.9	23.6	24.0	25.0	25.9	121.4

Source: GBA

10.8.3 Rates and Taxes

Western Power's forecast AA3 opex for insurance is shown in Table 10.27.

Table 10.27: Forecast AA3 Opex on Rates and Taxes ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
6.6	7.1	7.8	8.6	9.2	39.3

A total of $29.1 million of this amount is property taxes, land tax, local government rates equivalent, the fire and emergency services (FESA) levy and water and shire rates. For land taxes, Western Power obtained advice from the Valuer General's Office (Landgate Valuation Services) that nominal increases of the order of 8-10% per annum were advisable for budgeting purposes. Based on this advice, and making provision for future land purchases, an annual nominal increase of 10% was assumed. A similar increase was assumed for local government tax equivalent and the FESA levy based on a combination of the Valuer General's advice, historical trends and future land acquisitions. For water and shore rates a nominal annual increase of 5% was assumed, again in line with advice received from the Valuer General's office.

Western Power's original land tax forecast was based on the 2009-10 actuals and 2010-11 actuals were not known at the time. In the event, land related taxes reduced from $4.5 million in 2009-10 to $4.2 million in 2010-11 and Western Power has made an adjustment to reflect the revised base. However this adjustment has been offset by the correction of other errors so the net change is very small.

The remaining $10.2 million of this forecast is fringe benefit tax. Western Power has forecast this based on the 2010-11 actual which it has increased in line with the head count growth where it has used the value of the increased works program as a proxy for the increased head count.

In our view, both the land tax and fringe benefit tax forecasts appear high. An increase in land related taxes of 8%-10% nominal per year seems unsustainable over time and the reduction in taxes in 2010-11 appears to support this. However we are not in a position to propose an adjustment that is inconsistent with the advice Western Power has received from the Valuer General.

The escalation rate assumed for calculating the fringe benefit tax requirement is excessive. Western Power's forecast assumes an increase in head count of around 30% by the end of AA3, which we consider unlikely. We do not think that the value of the approved works program is a valid proxy for head count as much of the program is materials and much of the labour content is outsourced. This approach also overlooks the fact that a significant proportion of Western Power's internal labour costs are for corporate support and the majority of these costs are fixed. We propose that Western Power's base 2010-11 fringe benefit tax amount be compounded annually by 2% per annum, based on the net growth rates in Table 10.13.

On this basis our proposed AA3 opex requirement for rates and taxes is shown in Table 10.28.

Table 10.28: Proposed AA3 Opex for Rates and Taxes ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Property Taxes[1]	5.1	5.4	5.8	6.2	6.7	29.1
Fringe Benefit Tax	1.6	1.6	1.6	1.7	1.7	8.2
Total	**6.7**	**7.0**	**7.4**	**7.9**	**8.4**	**37.3**

Source: GBA
Note 1: As adjusted by Western Power.

10.8.4 EnergySafety Levy

Western Power's forecast AA3 opex for its EnergySafety Levy is shown in Table 10.29.

Table 10.29: Forecast AA3 Opex on Insurance ($ million, real 2011-12)

2012-13	2013-14	2014-15	2015-16	2016-17	Total
4.3	4.3	4.3	4.3	4.3	21.4

Source: Western Power

This level is generally consistent with the amount paid in AA2 and has not been escalated. We consider it reasonable.

10.9 INDIRECT COST ALLOCATION

Western Power's forecast AA3 opex for its indirect cost allocations is shown in Table 10.30.

Table 10.30: Forecast AA3 Opex Indirect Cost Allocations ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Total indirect cost allocations	54.30	51.34	50.25	48.31	54.90	259.09
Less non revenue cap allocations	2.97	2.81	2.71	2.65	2.96	14.11
Indirect cost allocations included in revenue cap opex	**51.32**	**48.53**	**47.53**	**45.66**	**51.94**	**244.98**

Source: Western Power

To assist us come to a view as to whether the indirect costs that were included in the opex forecast were reasonable, we asked Western Power to provide a breakdown of the allocated indirect costs for the AA2 and AA3 period. Western Power provided the required information for the AA3 forecast but in respect of the AA2 actuals it stated:

> *The section on AA2 indirect costs has been left blank. For the AA2 period, indirect costs cannot easily be apportioned on a regulatory category and activity basis. While total indirect costs are known for each year of AA2 historical expenditure, this cannot be simply applied as a flat rate across all categories of expenditure. There are two reasons for this:*
>
> 1) *Indirect costs are applied firstly on the basis of labour hours, at the rate of $6 per hour. The remainder is then allocated evenly across the works program as described in point 2.*
> 2) *Indirect costs are applied each month as a percentage rate to open work orders based on the proportion of expenditure incurred in the month. Indirect cost recovery is assessed regularly during the year and adjustments are made to the recovery rate where an over or under recovery exists. This will result in a different indirect cost allocation by activity when viewed on a full year basis.*

> *Therefore, different categories of work will incur a different proportion of indirect costs.*
>
> *The only way to accurately present historical AA2 indirect costs by regulatory category and activity would be to extract this information from Western Power's financial systems. This task is expected to take considerable time and resources to undertake. Please nominate if this is a requirement. If so, we will need to assess the time required to complete the work.*

While Western Power was not easily able to provide us with its indirect cost allocations for all regulatory categories it was able to extract the indirect cost for the base year for those line items where it used its scale escalation model to determine its forecast AA3 opex requirements (the shaded line items in Table 10.1). We therefore compared these indirect cost allocations with the equivalent allocations for 2012-13, the first year of AA3. This analysis is shown in Table 10.31.

Table 10.31: Comparison of 2010-11 and 2012-13 Indirect cost Allocations ($ million, real 2011-12)

	2010-11	2012-13	Change
Distribution			
Network Operations	-	-	-
Reliability	0.29	0.32	10.2%
SCADA and Communications	0.80	0.89	10.1%
Maintenance – Corrective Deferred	4.56	5.02	10.0%
Maintenance – Corrective Emergency	11.65	13.46	15.5%
Maintenance – Preventive Condition	7.89	10.49	32.9%
Maintenance – Preventive Routine	6.48	7.13	9.9%
Call Centre	-	-	-
Metering	0.09	0.20	125.5%
Transmission			
Network Operations	-	-	-
SCADA and Communications	1.59	2.13	34.1%
Maintenance – Corrective Deferred	1.67	1.84	9.8%
Maintenance – Corrective Emergency	0.38	0.42	9.8%
Maintenance – Preventive Condition	1.65	1.82	10.3%
Maintenance – Preventive Routine	2.96	3.26	10.0%
Total	**40.03**	**46.97**	**17.3%**

Source: GBA

The analysis in Table 10.31 indicates a step increase in indirect costs of 17.3% between 2010-11 and 2012-13, which has not been explained by Western Power. Moreover, the average rate of growth in the real indirect costs allocated to revenue cap opex over AA3 period is only 0.3%.

We think that indirect costs should be largely fixed and cannot see any justification for indirect costs to escalate by more than 0.63% per year (the network operations net growth escalation factor proposed in Table 10.13). We therefore suggest that the increase in indirect costs between the base year and the first year of AA3 be limited to 1.264% and that costs in subsequent years be reduced on a pro-rata basis. This implies a 13.69% reduction in all indirect costs allocated to opex. In our model we have applied this reduction to all costs on a pro-rata basis and our proposed adjustment is shown in Table 10.32.

We appreciate that the reduction is based on a high level analysis. However analysis of the information provided by Western Power indicates that some adjustment is necessary and the 2010-11 opex of $40.03 million that we used as a basis for determining the adjustment amount represents 78% of the total 2010-11 indirect cost allocation on revenue cap opex.

Table 10.32: Proposed AA3 Opex Indirect Cost Allocations ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17
Western Power allocation (Table 10,30)	51.3	48.5	47.5	45.7	51.9
Proposed adjustment (13.69%)	(7.0)	(6.6)	(6.5)	(6.3)	(7.1)

Source: GBA

10.10 PROPOSED AA3 OPEX

On the basis of the considerations discussed in this section, our proposed AA3 opex requirement, excluding efficiency adjustments is shown in the following tables. We developed our own opex model for this analysis. The model used an algorithm similar to that used by Western Power, although the analysis was undertaken at a higher level. It incorporated all the adjustments discussed in this Section 10 of our report. Table 10.33 presents the various components of the opex forecast at an aggregated level, while Table 10.34 breaks down our proposed AA3 opex by line item.

Table 10.33: Proposed AA3 Opex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Base Escalation	258.98	263.92	268.96	274.11	279.36	1,345.32
New Recurrent Opex	0.50	0.51	0.52	0.54	0.55	2.62
New One-off Opex	9.69	9.69	9.69	1.00	1.00	31.06
Zero Based Line Items	132.07	125.01	131.85	140.02	148.67	677.63
Indirect Costs	44.30	41.88	41.03	39.41	44.83	211.44
TOTAL OPEX	**445.53**	**441.02**	**452.05**	**455.07**	**474.40**	**2,268.07**

Source: GBA

Table 10.34: Proposed AA3 Opex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Distribution						
Network Operations	14.66	14.75	14.84	14.94	15.03	74.22
Reliability	1.84	1.87	1.89	1.92	1.98	9.50
SCADA and Communications	5.03	5.09	5.15	5.23	5.40	25.89
Smart Grid	4.97	3.99	4.75	6.20	7.60	27.51
Maintenance – Corrective Deferred	28.75	29.09	29.45	29.89	30.88	148.06
Maintenance – Corrective Emergency	73.21	74.02	74.91	75.97	78.53	376.64
Maintenance – Preventative Condition	58.97	59.50	60.09	50.87	52.62	282.04
Maintenance – Preventative Routine	40.54	41.04	41.58	42.21	43.66	209.04
Non Recurring Opex	6.23	7.24	7.15	7.08	7.29	35.00
Call Centre	7.24	7.40	7.58	7.75	7.93	37.90
Distribution Quotations	4.15	4.16	4.28	4.31	4.33	21.22
GSL Payments	1.70	1.70	1.70	1.70	1.70	8.48
Metering	20.09	20.54	21.01	21.49	22.00	105.13
Subtotal – Distribution	**267.37**	**270.39**	**274.38**	**269.53**	**278.95**	**1,360.63**
Transmission						
Network Operations	8.91	8.97	9.03	9.08	9.14	45.13
SCADA and Communications	12.09	12.21	12.34	12.50	12.89	62.03
Maintenance – Corrective Deferred	10.04	10.15	10.26	10.41	10.75	51.61
Maintenance – Corrective Emergency	1.14	1.14	1.14	1.15	1.21	5.78
Maintenance – Preventative Condition	9.85	9.96	10.09	10.24	10.59	50.72
Maintenance – Preventative Routine	17.35	17.54	17.75	18.00	18.62	89.25
Non Recurring Opex	13.74	6.28	11.02	13.86	20.04	64.94
Subtotal - Transmission	**73.12**	**66.24**	**71.63**	**75.24**	**83.24**	**369.47**
Corporate						
Business Support	71.16	69.50	70.36	73.12	73.63	357.76
Insurance	22.90	23.60	24.00	25.00	25.90	121.40
Rates and Taxes	6.70	7.00	7.40	7.90	8.40	37.40
EnergySafety Levy	4.28	4.28	4.28	4.28	4.28	21.42
Subtotal - Corporate	**105.04**	**104.38**	**106.04**	**110.30**	**112.21**	**537.98**
TOTAL PROPOSED OPEX	**445.53**	**441.02**	**452.05**	**455.07**	**474.40**	**2,268.07**

Source: GBA

10.11 EFFICIENCY ADJUSTMENTS

Western Power's opex forecast has made no provision for progressively increasing the efficiency of Western Power's opex. In addition, none of the adjustments that we have proposed in this section relate specifically to improvements in the efficiency with which Western Power undertakes its operations.

However the benchmarking results presented in Table 10.2 indicate scope for efficiency gains. This is supported by Western Power's own benchmarking in Section 7.9 of the

AA3 access arrangement information, which shows that Western Power's own forecast reflects a significant deterioration in operating efficiency by the end of AA3. Our review of Western Power's expenditure governance procedures also confirms that there is still significant scope for capturing further efficiencies in the way in which Western Power undertakes its operations.

In addition, there has been significant investment in modern and enhanced IT under the SPOW program since the beginning of AA2. This capex investment is expected to total $132.3 million between 2009-10 and 2014-15, when the major components of the program will be in place. The investment has been approved by the Western Power Board on the basis of the operating efficiencies that they will generate. However none of these efficiencies have been captured in Western Power's AA3 opex forecast.

It is difficult to assess the amount of efficiency gains that could potentially be captured during AA3 but, from what we have seen, an annual efficiency target of around 2% should be readily achievable. The impact of this potential efficiency gain is shown in Table 10.35.

Table 10.35: Impact of Efficiency Gain ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Proposed AA3 opex	445.53	441.02	452.05	455.07	474.40	2,268.07
2% efficiency gain	445.53	432.20	434.15	428.31	437.57	2,177.76

Source: GBA

10.12 SUMMARY

A summary of our proposed adjustments to Western Power's opex forecast is provided in Table 10.36.

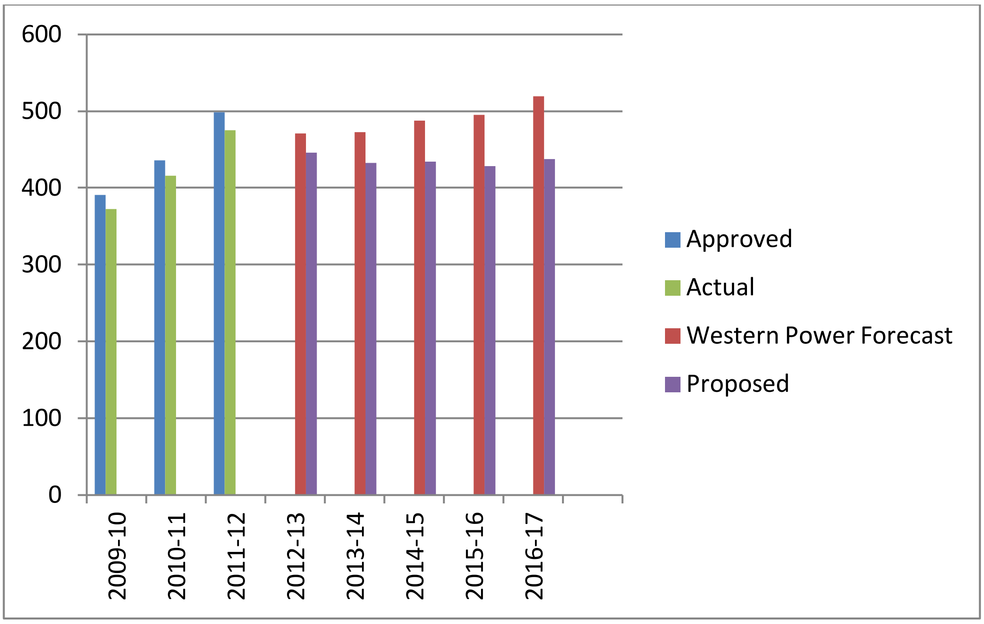
Table 10.36: Proposed AA3 Opex Forecast Adjustments ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power forecast	470.63	472.61	487.52	495.23	518.99	2,444.97
Proposed modelling adjustment	(25.10)	(31.59)	(35.46)	(40.16)	(44.59)	(176.90)
Model adjusted forecast	445.53	441.02	452.05	455.07	474.40	2,268.07
Proposed efficiency adjustment	-	(8.82)	(17.90)	(26.76)	(36.83)	(90.31)
Efficiency adjusted forecast	445.53	432.20	434.15	428.31	437.57	2,177.76

Source: GBA

Figure 10.1 provides a comparison between the AA2 opex allowed by the Authority, Western's Power's actual AA2 opex, the forecast AA3 requirement and the opex that we consider efficient inclusive of the proposed 2% compounding efficiency adjustment.

Figure 10.1: Comparison of AA2 and AA3 Opex ($ million, real 2011-12)



Source: GBA

APPENDIX A

NFIT REVIEW OF SELECTED AA2 CAPEX PROJECTS AND PROGRAMS

A1 DISTRIBUTION POLE REPLACEMENT

A1.1 BACKGROUND AND DESCRIPTION

This program covers the replacement of distribution poles that have reached the end of their serviceable life. It is an important program for Western Power as unassisted pole failures are a serious public safety hazard. They can also start bush fires, often causing extensive property damage. The program is therefore needed to mitigate an extreme asset failure risk for Western Power. This risk is exacerbated by the fact that a large proportion of Western Power's wood pole population is known to be in poor condition and large numbers of these poles are located in areas of extreme and high bush fire risk. The program is a key component of Western Power's broader wood pole management program, which was the subject of a the EnergySafety Order and also of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament.

The program considered in the review covers only pole replacements. It does not cover reinforcements, which are a separate component of the broader wood pole management program.

The provision for this program in the approved AA2 capex forecast was just over $203 million and covered the replacement of [redacted] poles at an average unit cost of roughly [redacted][58]. Western Power now expects to spend a little over $227 million in AA2, and replace an estimated [redacted] poles and considers that all expenditure on this program meets NFIT requirements. Due to the requirements of the EnergySafety Order, annual pole replacements were increased during AA2 as funds and resources became available.

A1.2 DOCUMENTS PROVIDED

Table A1.1 shows the documents provided by Western Power for this NFIT review.

[58] This value was adjusted down after the AA2 submission to an average unit cost of [redacted] due to revised pole replacement amounts which were wrongly reported.

Table A1.1: Documents Provided on AA2 Distribution Pole Replacement Program

Title	DMS#	Date
NFIT Compliance Summary for Distribution Pole Replacement	8806440v4	Nov 11
Business Case for the Replacement of Distribution Wood Poles 2009/10 to 2011/12	6787808	Jun 10
Board Papers		2009 and 2010
NFIT Evaluation Report for the Wood Pole Management Program	8567168v2	6 Sep 11
Wood Pole Failure Prediction Model	6860517v1	Feb 10
Wood Pole Asset Management Plan 2011-17	8172520(rev 1.1)	11 Nov 11
Wood Pole Inspection Procedure	5449945	May 11
Wood Pole Management Program	Mercor Consulting Pty Ltd	Sep 11
Wood Pole Management Plan	6811698	Jan 10
Distribution Poles and Related Data	709305	Nov 09
Pole Inspection and Treatment	3271852	Dec 10
Agreement on Scope of Work, Budget and Delivery (example)	6255999	-
Order Number 01-2000, Energy Coordination Act 1994 S.18B	http://www.docep.wa.gov.au/EnergySafety/PDF/Misc/Western Power_order.pdf	29 Sep 09
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A1.3 EFFICIENCY TEST

From the latest information provided by Western Power, the average unit cost of pole replacements during AA2 is expected to be [redacted]. This is [redacted] higher than the revised estimated unit cost of [redacted] at the time of the AA2 review. Table A1.2 shows the average unit pole replacement cost for each year of AA2 period and indicates that the expected 2011-12 unit cost is 17% higher than the unit cost in the previous year.

Table A1.2 Costs of Pole Replacements ($, real 2011-12)

	Real Prices (June 2012)		
	2009-10	2010-11	2011-12
Quantity	[redacted]	[redacted]	[redacted]
Unit cost	[redacted]	[redacted]	[redacted]
Total ($ million)	58.8	69.9	98.3

Source: Western Power

Western Power states that this increase in 2011-12 unit costs was primarily due to the impact of the following two cost drivers namely:

- An increase in labour costs for distribution delivery partners, which is due to increased workload and scarcity of trained labour. There has been an increased rate of retirements among Western Power's internal workforce and Western Power considers that it will be difficult to increase its internal workforce to meet the increased pole replacement demand. It will therefore have to rely more on its distribution delivery partners, with higher labour costs, in order to accelerate its rate of pole replacements; and

- An increase in the ratio of planned to unplanned pole replacements and the impact this has on the average unit cost. The wood pole replacement unit cost is a weighted average of planned and unplanned unit costs. Only a proportion of the expenditure for unplanned pole replacements is capitalised (45% of direct labour and material), which reduces the capitalised unit cost of unplanned pole replacements to below planned pole replacement unit cost. A proportional reduction of unplanned poles in the total volume of wooden poles will cause an increase in the overall unit costs.

The expected number of pole replacements in 2011-12 is approximately 20% higher than 2010-11. Western Power's wood pole requirements are sourced from a preferred vendor arrangement so material costs should be relatively stable and Western Power indicated that final negotiations with its distribution delivery partners resulted in a labour rate increase of 5.5%. However, between 2010-11 and 2011-12, due to the fully utilised internal workforce, pole replacements allocated to external providers was increased from 29% to 52% predominantly for planned work. This increase in outsourced planned work, together with the estimated external labour cost increase, altered the cost base significantly.

A1.4 SAFETY OR RELIABILITY TEST

Audits undertaken by EnergySafety have established that there are substantial numbers of wood poles on Western Power's network that require reinforcement or replacement. The potential consequences of unassisted wood pole failures are an extreme business risk for Western Power. This risk is highlighted by the high level of public interest in the issue and the fact that Western Power's wood pole management program was the subject on an Inquiry by a standing committee of the Western Australian Parliament. We are satisfied that the program meets the requirements of the safety and reliability test of the NFIT.

A1.5 CONCLUSION

Given the extreme risks to Western Power of unassisted pole failures and the escalating stakeholder concern over the consequences of unassisted pole failures, Western Power's decision to increase the number of pole replacements beyond the level anticipated at the time of the AA2 review was reasonable. Furthermore, the 3% increase in the average unit cost of pole replacements during AA2 above the level accepted by the Authority during the AA2 review does not seem excessive. However, the 17% increase in the unit cost of pole replacements between 2010-11 and 2011-12 is very high and has not, in our view, been fully justified by Western Power. Nevertheless, we acknowledge that Western Power has been under a lot of pressure to increase its rate of wood pole replacement and such pressure can make it difficult to tightly control costs. On balance, we think all AA2 capex on pole replacements meets NFIT requirements.

It is not clear to us why capex on unplanned pole replacements should be lower than on planned replacement, apart from the fact that unplanned replacements are likely to be undertaken by in-house staff with lower labour costs. Western Power appears to take the view that there is a fault response component to an unplanned pole replacement and this component should be treated as opex. This is reasonable. However, the basis for determining that the proportion of unplanned pole replacement cost that is treated as opex should be 55% is not clear. It may be more reasonable to capitalise a fixed amount, based on the average cost of a planned pole replacement, for each unplanned pole replacement and then treat the balance of the cost as opex. In particular, as the materials cost is likely to be little different between a planned and unplanned replacement, is unclear why 55% of the materials cost of unplanned pole replacements should be treated as opex.

We also have concerns, which we have not been able to fully resolve, regarding the treatment of replaced wood poles in the capital base. Table 72 of the AA3 access arrangement information indicates that no accelerated depreciation is been applied to replaced poles, except to poles removed as part of the State Underground Power Program. It is reasonable to assume that poles replaced as a result of condition assessments or unassisted pole failures would, on average, have reached the end of their economic life. However this would not necessarily be true for poles replaced after an assisted pole failure, such as after being hit by a car.

Our concern is whether pole assets are individually identified in the capital base or whether they are aggregated by asset category with each pole, in effect, assigned an assumed average life. Western Power has stated that, for the asset valuation undertaken at the commencement of AA1 the average remaining life of distribution wood poles was assessed to be 14.5 years. If all poles in existence at that time were assumed in the register to have this life, then all poles that were replaced as part of this program would still have a positive asset value at the time of replacement and should therefore have been be subject to accelerated depreciation on replacement. If this is the case, the value of the capital base will be overstated and customers may be paying Western Power a return on assets that are no longer in service.

A2 STRATEGIC PROGRAM OF WORKS (SPOW)

A2.1 BACKGROUND AND DESCRIPTION

The strategic program of works (SPOW) was established to manage a portfolio of IT projects to enhance Western Power's capabilities and business processes in areas including asset and work management, customer management, finance, human resources and logistics. These objectives were to be achieved through the replacement of outdated legacy IT applications and automating processes currently done manually. SPOW commenced in AA1, continued through AA2, and Western Power has included estimates for SPOW projects in its AA3 capex forecast.

The portfolio of IT systems within the SPOW includes: asset management; customer management; meter data management; network operations; works management and supply chain management; network planning; and enterprise support. Western Power has indicated that the SPOW for AA2 consisted of 20 individual projects of which 15 had expenditure in excess of $1 million. The two largest projects were the Integrated Solution for Asset Management (ISAM) and Mobile Workforce Solution (MWS) which together account for 44% of the expected total AA2 SPOW expenditure.

At the time of the AA2 review, the total forecast SPOW capex in AA2 was approximately $68 million. Western Power now expects to incur $82.7 million, an overrun of $14.7 million or almost 22%. Western Power considers that all actual AA2 SPOW capex satisfies NFIT requirements.

The reasons provided by Western Power for the overrun on the SPOW program were:

- Expenditure on the meter data management system was brought forward from AA3 period to 2011-12 due to an increased level of compliance risk using the existing system;

- Increased expenditure on the MWS (including additional expenditure to activate the wood pole inspection pilot project and enhance a larger mobile program) and the enhanced planning and works management (EPWM) programs; and

- Expenditure on the Ellipse upgrade exceeded the AA2 forecast due to a requirement to fund part of the project through outsourcing following the resignation of key personnel.

Out of the 20 individual SPOW projects, Western Power has only submitted NFIT compliance information for the ISAM and MWS projects. We asked it to supply information on the MDM project so that our review would cover more than 50% of the total program expenditure. Western Power did not provide this information as the NFIT compliant amount for this project is still under investigation.

The ISAM project involves the replacement of Western Power's current geographic information system (GIS) and the design and implementation of an asset management system. The MWS project includes the provision of a mobile solution for all planned field work.

A2.2 DOCUMENTS PROVIDED

Table A2.1 shows the documents provided by Western Power for this NFIT review.

Table A2.1: Documents Provided on the SPOW

Title	DM#	Date
Strategic Program of Works (SPOW) Overview	8821900	Nov 11
Statement of Program Intent	6172280	24 Jun 09
NFIT Compliance Summary for ISAM (including the Project Management Plan DM# 7363368v1, Business Case DM# 6242018 and change requests)	8600576	Nov 11
NFIT Compliance Summary for MWS (including the Project Management Plan DM# 6505358, Business Cases DM#6262061 and DM# 8235501, IT Sourcing Evaluation Report, and Change Variation and Interim Funding DM# 8461753v2)	8784613	Nov 11
Gate 2 (Planning Output) Business Case – MDM Investigation	8649852	Aug 11

Source: GBA

A2.3 DISCUSSION

A comparison of the actual and budget capex on the ISAM and MWS is provided in the Table A2.2 below.

Table A2.2: Comparison of Actual and Budget Expenditure ($ million, real 2011-12)

	ISAM		MWS	
	Business Case	**Actual**	**Business Case**	**Actual**
2009/10	4.75	3.44	3.19	2.24
2010/11	9.21	7.67	2.26	3.81
2011/12	9.01	10.10	9.37	8.78
Total	**22.97**	**21.21**	**14.81**	**14.83**
AA2 Forecast	24.20		11.74	

A2.3.1 ISAM

Approximately $0.2 million of the cost of this project will occur in AA3 but nevertheless the project is expected to come in under budget. Western Power expects that the project will introduce efficiencies into its operation and will have a positive net present value through an ongoing reduction in opex. It has quantified these efficiencies as $3.75 million per annum through staff reductions, simplified business processes and automated procedures amongst other benefits and expects to capture 50% of these efficiencies in 2012-13. The efficiency gains will occur in the areas of distribution delivery; transmission delivery; customer network connections; operational asset management; distribution programs and work integration; network asset performance; transmission primary plant; access arrangement; corporate accounting and taxation; and standards, policy and data quality.

Western Power has also applied the safety and reliability test to this project and indicated that, without the project, the operation of the business asset management functions will become unreliable due to disparate computer applications and databases.

A2.3.2 MWS

This project is disaggregated into two separate phases as shown in Table A2.3.

Table A2.3 Disaggregated Budget for MWS ($ million, real 2011-12)

Description	Cost	Comment
Phase 1		
Original estimate	3.2	Phase 1 business case approval
Variation 1	2.3	Change order approval
Variation 2	3.4	Incorporated into Phase 2 business case approval
Total Phase 1	**8.9**	
Phase 2		
AA2 component	6.0	Phase 2 business case approval
AA3 Component	1.5	Phase 2 business case approval
Total Phase 2	**7.5**	

Phase 1 of the project, as set out in the business case, covered the purchase of a mobile solution and the implementation of the solution for wood pole inspections for an estimated cost of $3.2 million. The business case showed a negative NPV. However the NPV analysis did not include unquantified benefits that were included in the business case, including productivity savings, process automation and the potential to successfully address current issues with the management of the wood pole inspection program. The business case was approved by the Board on this basis.

This approved budget was exceeded by at least $1 million without proper approval. Following an internal review of the reasons for this overrun, and to confirm that the project design and strategy was optimal, a change order for $2.3 million approved by the Board to complete this phase. A second variation of $3.4 million was incorporated into the phase 2 business case increasing the total phase 1 cost overrun to approximately 178%.

We consider that Western Power's review of the different mobile solutions available before preparing this first business case was inadequate. We speculate that the project may have been rushed so that Western Power was seen to be doing something to address the problems it was experiencing with the wood pole management program. We also consider that the project management of the phase 1 implementation was poor. The project cost was allowed to overrun by more than 30% without proper approval. Western Power's internal review identified reasons for the cost overrun including the unavailability of resources to meet the proposed timelines and changing business requirements. As these were risks foreseen in the business case (and appropriate mitigation measures identified), we believe they should have been identified and mitigated earlier. The extent that the project was redesigned as a result of this internal review is unclear to us but it does seem some redesign was necessary. We conclude that the project was poorly configured as a result of inadequate initial planning and that, when these deficiencies became apparent, the problems were not addressed in a timely manner. In our view, had better governance and project management been applied to this program, it should have been completed at a cost much closer to its original budget.

The phase 2 business case was for the approval of $10.9 million capex (including $3.4 million for completion of phase 1 and $1.5 million for AA3). This includes extending the scope of the MWS program beyond wood pole inspections. We are not aware of any problems with the implementation of this phase.

A2.3.3 MDM

We requested further information from Western Power on this subproject and were provided a business case to support its estimated AA2 capex. However the business case supported expenditure of $1 million through to the end of AA2, significantly less than the $5 million provided for in the F1 forecast of AA2 capex for the SPOW program.

A2.4 NET BENEFIT TEST

Western Power has indicated that the ISAM project will result in a significant positive NPV through the reduction in ongoing operating costs. Moreover, it considers that the expenditures meet the safety and reliability test as without the project, the operation of business asset management functions will become increasingly less efficient.

As for the MWS project, Western Power has indicated that the expenditures meet the safety and reliability test as, without the project funding, Western Power will continue to suffer from the inefficiencies and long cycle times within its current manual asset inspection process which will in turn impact the ability of Western Power to achieve efficiencies in the business' asset management practices. We agree with this and note that mobile workforce solutions have now become an industry standard asset management tool.

We think the net benefit test, rather than the safety and reliability test, should generally be applied to projects in the SPOW program as the overriding objective is to improve the efficiency of Western Power's operation.

However, in principle we consider that all projects in the SPOW program have the potential to satisfy the net benefit test, notwithstanding the fact that many benefits are difficult to quantify. The IT solutions being implemented under this program have generally been adopted by the leading network service providers in the industry and all have the potential to, over time, increase the efficiency of Western Power's business processes.

A2.5 CONCLUSION

We consider that all capex incurred during AA2 on the ISAM and the second phase of the MWS satisfies NFIT requirements. However, it appears that much of the cost overrun on the first phase of the MWS arose through process inefficiencies. We think insufficient time was spent researching and evaluating alternative approaches to addressing the need, possibly because the schedule did not allow adequate time for project development. We conclude that the initial project cost estimate satisfies NFIT requirements but have seen no evidence to suggest that the cost variations would have been necessary had the initial project development been more comprehensive. We are therefore not satisfied that the $5.7 million cost overrun on this phase meets NFIT requirements.

The projects reviewed in this section account for only for only 44% of the expected $82.7 million AA2 capex on this program. In its AA3 access arrangement information, Western Power indicated that it considered the full expected capex amount satisfied NFIT requirements and included the full amount in the AA3 opening capital base. However it was subsequently unable to fully support its estimated AA2 NFIT amount on the MDM project. We are therefore unable to form an opinion on the extent that the capex we have not reviewed might satisfy NFIT requirements.

A3 SMART GRID FOUNDATION PROGRAM

A3.1 BACKGROUND AND DESCRIPTION

The approved AA2 capex forecast for the smart grid foundation program was just over $45 million. Western Power is now indicating that it considers its actual AA2 capex of just over $18 million[59] satisfies NFIT requirements. This is 60% less than the approved forecast.

The smart grid foundation project was an investigation into the deployment of intelligent devices throughout the distribution network to improve energy utilisation, corporate reputation and customer service. The program had the support of the Minister, the Authority, the Office of Energy and Synergy.

The program consisted of a number of individual subprojects, involving both capex and opex, of which the smart grid advanced metering infrastructure capital subproject accounted for the largest expenditure portion. It was envisaged that after the success of this subproject, which accounted for 45% of the forecast program capex, the replacement of non-compliant three phase meters with smart meters would commence. However, during AA2, only the smart grid advanced metering infrastructure subproject was completed. The three phase smart meter rollout did not commence during AA2 for the following reasons:

- Additional time was required for stakeholder engagement;
- Additional time was required for further data collection on the Perth solar city trial;
- Additional time was required for the development of more meter deployment options and strategies; and
- Additional time was required to develop a robust procurement process.

Western Power considers that the smart grid advanced metering infrastructure subproject met its objectives and provided useful information relevant to the ongoing implementation of the smart grid program. A number of operations benefits have already been realised, including the ability to remotely connect and disconnect consumers participating in the program and to remotely read their meters.

[59] The forecast investment has been updated with the F1 forecast.

A3.2 DOCUMENTS PROVIDED

Table A3.1 shows the documents provided by Western Power for this NFIT review.

Table A3.1 Documents Provided on the Smart Grid Foundation Program

Title	DMS#	Date
NFIT Compliance Summary for Smart Grid AMI Foundation Project	8798039	Nov 11
Business Case Opex and Capex Smart Grid Program	WE_n5444221_v12_BUSINESS_CASE_OPEX_AND_CAPEX_SMART_GRID_PROGRAM.doc	-
Western Power Presentation – Smart Grid Program	5074720	Dec 08
Smart Grid – AMI Trial Post Implementation Review – Interim Report	7955175	Jul 11
Sourcing Strategy – Smart Grid-AMI Foundation Project	6225896v2A	Jul 09
AMI Foundation Project Plan	5013013	Sep 08
Western Power Presentation – Smart Grid AMI Foundation Project – Summary – Work Parcel 1 Tender Evaluation & Recommendation	6719581	-
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A3.3 DISCUSSION

In assessing the implementation efficiency of the smart grid advanced metering infrastructure subproject, we note the following:

- Western Power relied on dialogue with vendors and eastern state utilities involved in similar projects to refine costs;
- The program was developed in consultation with Western Power executive management, Synergy and the Office of Energy, the Authority and other utilities;
- A number of potential suppliers of smart meters, communication and network management system infrastructure assisted in program design;
- Western Power followed its governance processes throughout the program and prepared a program sourcing strategy document; and
- While it was planned that planned 10,500 smart meters would be trialled in four metropolitan locations, Western Power actually completed 11,446 installations.

The smart grid advanced metering infrastructure subproject was a research project that will not provide a positive net benefit to Western Power, but it will potentially lead to a larger project which appears to have the potential of providing a positive financial net benefit. A cost benefit analysis shows that a full smart grid deployment is expected to deliver significant positive financial net benefit over a 20-year or longer period[60].

A3.4 CONCLUSION

This was a pilot program undertaken with the agreement of key Western Power stakeholders. At the time it was approved, there was a reasonable expectation that it would lead to a more extensive smart grid roll out that would provide a positive net benefit.

60 NERA Economic Consulting report dated February 2008 concluded that there would be a positive financial net benefit associated with a smart meter rollout for Western Australia. See Appendix B8 for more information on the proposed follow-on project.

Based on the information provided, the capex subproject appears to have been implemented efficiently. We are satisfied that it meets the requirements of the efficiency test.

The incremental revenue test, the net benefits test and the safety and reliability test are not relevant to a pilot project of this nature. However given that the cost is relatively low, and that the project appears to have been well planned and implemented with the support of key stakeholders, we think the actual AA2 capex should be included in the AA3 opening capital base.

A4 BUSHFIRE MITIGATION - WIRES DOWN

A4.1 INTRODUCTION

The original AA2 capex forecast for the bushfire management program was approximately $122 million. Around $100 million was actually spent and Western Power considers this all meets NFIT requirements. A portion of this capex relates to the wires down component of the program. The forecast for this component was nearly $41 million and the actual expenditure amounted to just over $41 million. This appendix discusses only this component of the bushfire mitigation capex program.

The wires down component involved the replacement of unserviceable overhead conductors in extreme and high bushfire risk zones. Wires down incidents caused by conductor failure are the second largest cause of asset initiated fires and therefore Western Power classifies wires down incidents as high risk in its risk management framework. Five or more bushfire incidents were experienced annually from 2006-07 to 2009-10 due to conductor failure and the trend is showing an overall increase[61].

A4.2 DOCUMENTS PROVIDED

Table A4.1 shows the documents provided by Western Power for this NFIT review.

Table A4.1 Documents Provided on the Bushfire Mitigation - Wires Down Project

Title	DMS#	Date
NFIT Compliance Summary for Bushfire Mitigation Wires Down	8798107	Nov 11
Business Case for the Bushfire Mitigation "Wires-down" Program 2009/12 to 2011/12	6937587	Jun 10
Project Estimating / Deliverability Checklist	6124113v1	-
Bushfire Management Plan 2009 2010		-
Wood Pole Inspection Procedure	5449945	May 11
Bushfire Management Plan 2010 2011		-
Bushfire Management Plan	8293574	Jul 11
Scope of Work – BFMP – SV 501.0 CHIDLOW – SV/Z006	8124496	Apr 11
Scope of Work – South Country Conductor Replacement – HV Network – WP138 – William Bay – ALB 530 – Lower Denmark Feeder	7393832	Apr 11
Bushfire Mitigation Wires Down Strategy (Metro Area) – Field Report		-
Hendrix Covered Conductor Manual	5523521	May 10
Board Paper	DD/MM/2010 – 10.B01.0001	Nov 10
Distribution Bushfire Mitigation (Wires Down) Strategy	6724338	-
Networks Bushfire Management Plan Strategy	3009109v1	Nov 11
Bushfire Management Implementation Plan 2010/2011	7133793	Oct 10
Project Closure Form	7794086v1	-
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

[61] Refer Business Case for the Bushfire Mitigation "Wires-down" Program 2009/10 to 2011/12, dated June 2010, DM# 6937587.

A4.3 EFFICIENCY TEST

We note the following points that we consider are directly or indirectly relevant to the efficiency test:

- The starting point for the AA2 wires down capex forecast was the overhead line length that at the time had already been identified as unserviceable from asset inspections. Western Power then added its estimate of the additional line length that may be identified as unserviceable from inspections undertaken over the AA2 period;

- Approximately 43% of wires down incidents can be attributed to conductor and other line equipment failure. The remainder is due to external factors;

- Prior to July 2010, conductor assessments were undertaken as part of the routine wood pole inspection program. However, it appears that the main focus of these inspections was pole condition and the conductor condition data collected was neither consistent nor comprehensive. Hence it did not provide reliable information on conductor condition. Western Power also collected information on a reactive basis but this is not collated in the same data set as the assessment data from the pole inspections;

- Western Power commenced a bundled asset inspection program in July 2010 that, amongst other things, specifically required conductor condition to be assessed and reported. This program should provide improved conductor condition information and is expected to increase the length of conductor determined to be unserviceable and requiring replacement;

- Western Power's business case looked at different options for mitigating the wires down risk. It decided to replace the serviceable conductor with new bare conductor, insulated overhead conductor or underground cable, as determined on the basis of a case by case assessment. We consider this approach reasonable;

- Over time, Western Power is planning to ramp up the quantity of conductor replacements from a line length of 120 km per annum (achieved in 2009-10) to 250km. Deliverability is not seen as a risk to achieving this accelerated target;

- Western Power indicates that 73% of the expenditure is labour and plant related costs and that these resources will be contracted or provided in-house. In the event Western Power resources are used, well-developed work practices will be adhered to. Material cost forms roughly 22% of the program cost and the remaining 5% is allocated towards project management; and

- Benchmarking of unit costs has not been undertaken, which is something we think Western Power could attempt. However, Western Power states that estimating the expenditure required for this program is difficult due to the variance in costs for different sub-project solutions.

A4.4 SAFETY OR RELIABILITY TEST

This program is directed at reducing the risk of fires being initiated by overhead conductor failure. It endeavours to improve and maintain the safety of the network in accordance with the Electricity Regulations 2001 (Supply Standards and System Safety). The program also reduces the risk of electric shock, improves system reliability and should in time reduce expenditure on fault and emergency maintenance.

A4.5 CONCLUSION

We have found it difficult to directly assess the efficiency of Western Power's expenditure on this program during AA2. However, the largest expenditure component of the program is labour and we assume that Western Power's governance processes have assured procurement and implementation efficiency. Indeed, we have seen nothing to indicate inefficiency in Western Power's implementation of this program. It is clear that the new facility is required to maintain the safety and reliability of the network

We consider that the program meets the requirements of the NFIT.

A5 METERS & ASSOCIATED EQUIPMENT

A5.1 BACKGROUND AND DESCRIPTION

The original AA2 capex forecast for this program was approximately $39.7 million. Western Power actual AA3 expenditure is expected to be approximately $43.3 million[62], 9% higher than the forecast. Western Power considers that all its actual capex meets NFIT requirements.

The program covers the supply, installation and commissioning of new and replacement low voltage meters. Western Power is obliged under the Metering Code to ensure that there is a metering installation at each connection point, and that the metering installation complies with the requirements of the Metering Code, the Service Level Agreements, and the Electricity Industry Customer Transfer Code 2004.

All procurement of metering equipment and associated services is undertaken in accordance with Western Power's procurement policy which in turn is consistent with Western Power's broader commercial principles. The program is governed by Western Power's capital program governance procedures.

Actual capex was higher than forecast at the beginning of AA2 due to the higher than forecast volume of meter changes that has occurred as a result of the PV (solar) program. Western Power stated that it was required to purchase and install 40% more meters in 2010-11 than provided for in the original forecast.

A5.2 DOCUMENTS PROVIDED

The documents shown in Table A5.1 were provided by Western Power for this NFIT review.

Table A5.1: Documents Provided on Metering Program

Title	DMS#	Date
NFIT Compliance Summary for Metro LVAP Meters <63 Amps	8806306	Nov 11
Metering Management Plan	1526607	Aug 06
Western Power's Procurement Policy	4096273	
Western Power's Commercial Principles	4472656	
Program Governance Framework	5200741	
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A5.3 EFFICIENCY TEST

Western Power has limited control over the quantity, timing and nature of new meter installations under this program since the factors are determined by the timing of new connections and the capacity and type of load at each connection.

Table A5.2 estimates the unit cost of meter installation and replacement over the period 2006-12. The table indicates that average unit rates for meter installation and replacement has reduced over time. This could be due, in part, to the fact that the proportion of meter replacements has increased and we would expect the installation cost of a meter replacement to be lower than that of a new meter. Alternatively it could be due to the purchase of more meters than needed. In the AA3 access arrangement information Western Power indicated that during AA3 it expects to install or replace approximately 56,000 meters each year but in 2010-11 it purchased almost 73,000

62 The forecast has been updated to include the F1 expected 2011-12 capex.

meters. We understand this was in anticipation of an increased requirement to support PV installations but this has not materialised because of reductions to the feed in tariff. We would have expected the F1 forecast for 2011-12 to have been lower as a result of this stock build up.

Table A5.2: Meter Cost Analysis ($ real 2011-12)

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
Actual expenditure ($million)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
No of meter purchases	33,564	37,019	38,048	49,730	72,841	
No of new connections	28,440	24,723	25,524	26,299	24,614	
Estimated unit cost ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Source: GBA

We also asked Western Power to clarify the accounting treatment of meters that were replaced. Western Power advised:

> *An assessment is performed to determine if the installed meter is capable of supporting PV. If it is, we re-program the meter to support bidirectional recording and therefore is not replaced. Electromechanical "dial" meters that can't be re-programmed and are no longer our standard meters are scrapped.*
>
> *As discussed in 10.2.1 of the [AA3 access arrangement information], we establish the value of the capital base using the roll-forward method. In establishing the value of the capital base we retain the asset in the capital base for the duration of its economic life. This ensures that the asset value is fully depreciated (on a straight line basis) over the economic life of the asset, providing for the full recovery of our initial investment in net present value terms.*

This accounting approach leaves assets in the capital base after they have been removed and disposed of. While this ensures that Western Power fully recovers the cost of its investment it may also result in consumers being overcharged since they must provide Western Power with a return on the value of assets that are no longer in service.

A5.4 SAFETY OR RELIABILITY TEST

Under the Metering Code, Western Power must ensure that there is a metering installation at each connection point, and that the metering installation complies with the requirements of the Code, the Service Level Agreements, and the Electricity Industry Customer Transfer Code 2004.

The program is required for the provision of covered services and therefore satisfies the requirements on the safety and reliability component of the NFIT.

A5.5 CONCLUSION

We consider that, in principle, the program satisfies NFIT requirements. However, the F1 forecast for 2011-12 does not appear to take into account the purchase of surplus meters in 2010-11 and thus could be high. To this extent the actual A2 capex meeting NFIT requirements could be overstated.

Western Power's practice of not applying accelerated depreciation to meters that are removed from service and replaced, means that the value of the capital base is over-stated. The reason for this accounting approach is to ensure that Western Power fully recovers the investment cost of assets that are removed from service before being fully depreciated. However it also means that consumers may be being overcharged by having to pay a return on the value of assets that are no longer in service.

A6 POWER QUALITY COMPLIANCE PROGRAM

A6.1 BACKGROUND AND DESCRIPTION

The AA2 forecast for the power quality (PQ) compliance program was approximately $35 million. The actual expenditure during AA2 is expected to be $16.2 million[63], all of which Western Power considers meets the NFIT requirements.

The PQ compliance program is a reactive capex program to address failures to meet compliance requirements and power quality matters identified through customer complaints[64]. At the time of submitting the AA2 capex forecast, historical data analysis suggested approximately 465 PQ projects would be required during AA2. This was based on an estimated 7% year on year reduction in the volume of PQ complaints consistent with a decreasing trend. The program also included the installation of PQ monitoring equipment to monitor PQ performance of the distribution network.

Western Power has identified the following reasons why actual expenditure has been significantly lower than forecast at the time of the AA2 review:

- The number of projects in the forecast was over-estimated. As part of program governance, the approach to forecasting project numbers was revisited and revised in 2010. The revision took into account a more extensive set of historical data captured specifically to improve the accuracy of the PQ work volume forecasts. This resulted in a forecast reduction from 465 to 234 PQ rectification projects.

- There was a substantial reduction in unit project costs from 2007-08 to 2009-10 due to improved service delivery; and

- The installation of additional PQ meters was removed from the scope, as additional PQ meters were installed in AA1 and 2009-10.

Western Power also introduced a more proactive low voltage upgrade program; however this program did not have a material impact on the level of work during AA2.

A6.2 DOCUMENTS PROVIDED

The documents shown in Table A6.1 were provided by Western Power for this NFIT review.

Table A6.1: Documents Provided on PQ Quality Program

Title	DMS#	Date
NFIT Compliance Summary for AA2 PQ Compliance Program	8796973	Nov 11
LV Network Supply Quality Forecast Study 2008/09	4498874	29 Feb 08
Network quality and reliability of supply management plan 2009/2010	4497339v3	Jul 09
Power Quality Complaint Handling Process Manual	3732350	Jun 07
Power Quality Compliance - Reinforcement of LV Network (AA2) 2009/10 to 2011/12	7401605	Aug 10
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

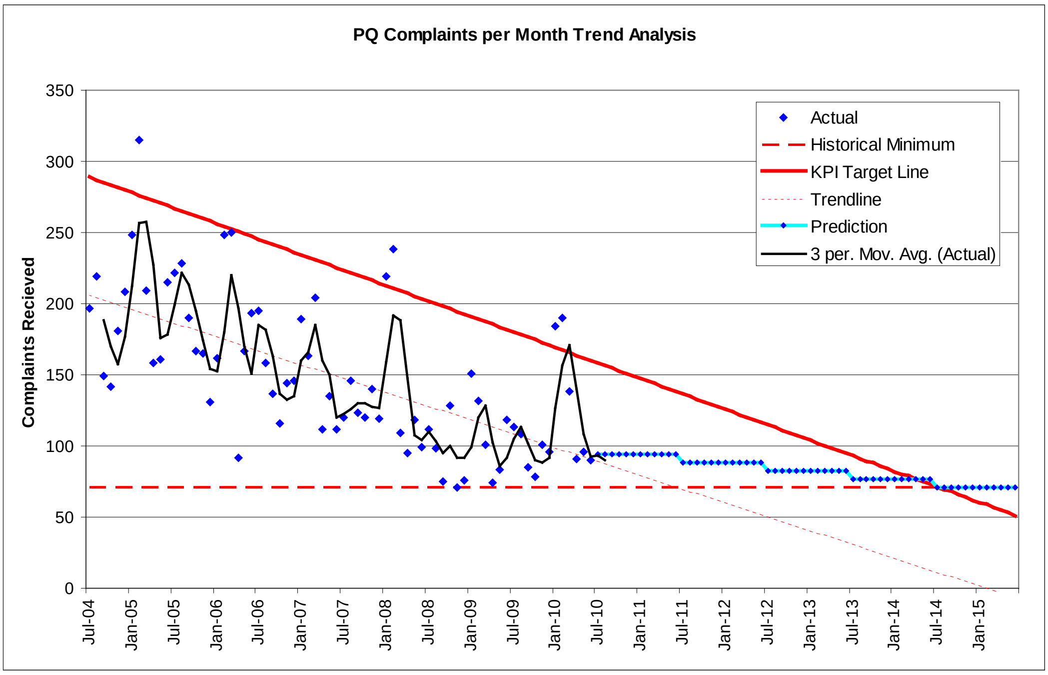
63 The forecast investment has been updated with the F1 forecast.

64 Western Power indicates that standards for power quality are specified in a number of regulatory instruments, notably the Electricity Industry (Network Quality and Reliability of Supply) Code 2005, the Technical Rules 2007 (WA) and the Electricity Act (1945) as well as the Electricity (Supply Standards and System Safety) Regulations 2001.

A6.3 EFFICIENCY TEST

The reduction in the number of PQ rectification projects during AA2 is substantial and results in a decrease of almost 50% from the original forecast. It is apparent that there has a substantial decline over time in customer complaints received from 2004. Furthermore, it appears that the original forecast of the number of PQ rectification projects was based on high historical complaint levels and that Western Power may have underestimated the extent that complaints would reduce over AA2. Figure A6.1 shows the reducing trend in customer PQ complaints over the period 2004 to 2010.

Figure A6.1: PQ Complaints per Month



Source: Business Case, Power Quality Compliance - Reinforcement of LV Network (AA2) 2009/10 to 2011/12, DM# 7401605.

Based on the above figure, it would appear that the forecast quantity of complaints per annum over the AA2 period was in the region of the lowest complaint quantity in historic years.

If the original forecast is adjusted for the reduced number of projects, and it is assumed that the average project cost does not change, the revised budget would be $17.6 million, 9% higher than the expected actual AA2 cost. Table A6.2 shows the average project costs for each year over the period 2005-12. The table shows there was a step increase in average project cost in 2006-07. We investigated whether this was the result of inefficiency, but Western Power has advised hat the average project cost for 2006-07 was erroneously based on the number of jobs received rather than completed. The corrected average project cost was of the order of $87,000 per project. This is actually higher than the average project cost in following years.

Individual projects are small. For each project there is usually a single obvious solution so inefficiencies due to the implementation of a non-optimal solution are unlikely.

Table A6.2: Analysis of Average PQ Rectification Project Costs

	Years						
	2005-06	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**
No of PQ rectification projects	240	116			81	79	74
Actual cost ($ million, nominal)	8.36	5.70	8.80	6.21	5.17		
Reported average cost per project ($, nominal)	34,829	49,160	75,560	64,860	64,280	64,000	
Adjusted average cost ($, real 2006-07)		49,160	72,301	61,170	58,827	56,534	

Source: Western Power

A6.4 SAFETY OR RELIABILITY TEST

Projects performed under this program arise because of a valid customer complaint from which it is established that, as a result of shortcomings in the Western Power distribution network, customers are not receiving the quality of supply to which they for which they have contracted.

Based on the above, we consider that the program passes the reliability test.

A6.5 CONCLUSION

We consider the program fully meets NFIT requirements. However, the AA2 capex forecast was high, apparently because of errors in the forecasting methodology used by Western Power for this program. While the correct amount will be included in the opening AA3 capital base, funding during AA2 for the full forecast capex was provided for in the AA2 access arrangement. As this program is not subject to the investment adjustment mechanism, there is no mechanism in the regulatory arrangements for the any excess funding to be returned to customers.

A7 TRANSMISSION SUBSTATION NOISE MITIGATION PROGRAM

A7.1 BACKGROUND AND DESCRIPTION

Western Power is required to manage noise emissions from all assets in accordance with the Environmental Protection (Noise) Regulations 1997. The dominant noise source from transmission substations is the power transformer.

In 2006, the Minister for the Environment issued "The Environmental Protection (Western Power Transmission Substation Noise Emissions) Approval 2005" (Ministerial Approval). This approval requires:

- all specified transmission substations to be partially compliant by 31 December 2009 (with a maximum permitted noise higher than the noise limits specified in the Regulations);
- all specified transmission substations to be fully compliant with the Regulations by 31 December 2019;
- the implementation of a remedial program to achieve the required levels of noise reduction to comply with the conditions by the specified dates; and
- reports of annual progress to the Department of Environment and Conservation (DEC).

A total of 34 substations are specified in the Ministerial Approval

Western Power developed a program of works to address the non-compliance. The total capex for the noise mitigation program included in the AA2 access arrangement was $36.44 million. The program included $8.85 million for Phase 1, which included 12 noise mitigation projects high priority substations based on exceedence levels and community impact, and $27.59 million for a Phase 2 program covering lower priority substations. Actual capex during AA2 is expected to be only $3.6 million on substations in the Phase 1 program.

Western Power considers that most of the work required to comply with the Ministerial Approval is unnecessary and negotiations with the DEC and the Environmental Protection Authority (EPA) continue. Hence the Phase 2 program is currently on hold. Western Power is also investigating the availability of cost effective solutions to meet the requirements of the Ministerial Approval.

A7.2 DOCUMENTS PROVIDED

The documents shown in Table A7.1 were provided by Western Power for this NFIT review.

Table A7.1: Documents Provided on the Transmission Substation Noise Mitigation Program

Title	DM#	Date
Transmission Substation Noise Mitigation Program Phase 2 - Summary of Current (AA2) and Future (AA3) Positions	8797718	Nov 11
Ministerial Submission Exemption from Environmental Protection (Noise) Regulations 1997 (WA)	6254722	none

Source: GBA

A7.3 DISCUSSION

Western Power explored a range of options in its preparation of the AA2 capex forecast for this program. The options included:

- whether or not to achieve improved or full compliance with noise obligations;
- whether or not to change Western Power's obligations through available avenues;
- whether to defend any prosecution resulting from non-compliance. The possibility of being prosecuted for non compliance with the Ministerial Approval was considered real; and,
- whether or not to include any capital funds for remedial action.

Western Power's final position at the time of the AA2 review was that it did not consider that full compliance with the Ministerial Approval was in the best interest of its customers. However, it also considered the potential reaction of the DEC in response to non-compliance. Given these, Western Power proposed in its AA2 submission, a program for full or partial compliance and at the same time to take appropriate action to change its obligations through all avenues available under the Noise Regulations. However its final AA2 forecast included sufficient provision to achieve full compliance.

Western Power's current negotiations with the DEC and EPA indicate that a revision to the Regulation 17 Approval of the Noise Regulations is likely to be achieved. The revision is expected to include the mitigation of only the highest noise emitting transmission substations in AA3, while the remainder are to be addressed in AA4. Throughout this process, Western Power also indicated that it has been able to demonstrate to the DEC that the work undertaken to address noise compliance at the targeted individual sites is progressing with significant gains in noise mitigation during the AA2 period.

Given these developments, Western Power has not been required to proceed with the work included in the Phase 2 Program and therefore has not incurred the associated expenditure in the AA2 period.

A7.4 CONCLUSION

We consider that Western Power's expected capex on this program during AA2 meets NFIT requirements.

A8 SECOND PICTON-BUSSELTON 132 KV LINE

A8.1 BACKGROUND AND DESCRIPTION

The forecast capex for the project at the time of the AA2 review was approximately $25 million (including both transmission and distribution related costs). The project has now been deferred but Western Power considers that $102,000 of capex spent on the project prior to its deferral meets NFIT requirements.

The second Picton-Busselton 132kV line was planned to maintain the reliability and security of supply to the Busselton and Margaret River regions since, in the absence of a second 132 kV line, it was forecast that the loss of the existing Picton-Busselton 132 kV line would create an under-voltage condition at times of peak demand. This under-voltage condition would breach the voltage level limits specified in Section 2.2.2 (Steady State Power Frequency Voltage) of the Technical Rules.

To mitigate this under-voltage, Western Power planned to build a second 132 kV line between the Picton and Busselton substations at an estimated cost of $22 million for transmission related costs and an additional $3 million for distribution related costs. While Western Power also identified other advantages of the second line (for example integration with other programs), the main driver appeared to be mitigation of the potential under-voltage condition. At the time alternative solutions were investigated, including that of reactive power compensation, to defer the need for the second line. However, Western Power indicated that, the 2007 load trend report indicated high rates of peak demand growth in the Busselton and Margaret River regions.

Western Power's 2010 review of the AA2 capex program included a review of the needs and drivers of this project. Updated load forecasts were reviewed and found to be lower than those used for the AA2 submission. Based on the latest peak demand forecast, Western Power now considers the most economically efficient long-term solution to the potential under-voltage issue is to install capacitor banks in the short term and defer the second line to a later date.

A8.2 DOCUMENTS PROVIDED

The documents listed in Table A8.1 were provided by Western Power for this NFIT review.

Table A8.1: Documents Provided for Picton-Busselton 132 kV Line

Title	DMS#	Date
Additional notes: Transmission Capacity Expansion: AA2 expenditure review and the second Picton-Busselton 132kV line NFIT Compliance Summary	8815138	15 Nov 11
Work Program Annual Submission Capital and Operating Expenditure 2011/12	7440566	Jan 11
10 Year Transmission Network Development Plan (TNDP)	8539410	15 Jul 11
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

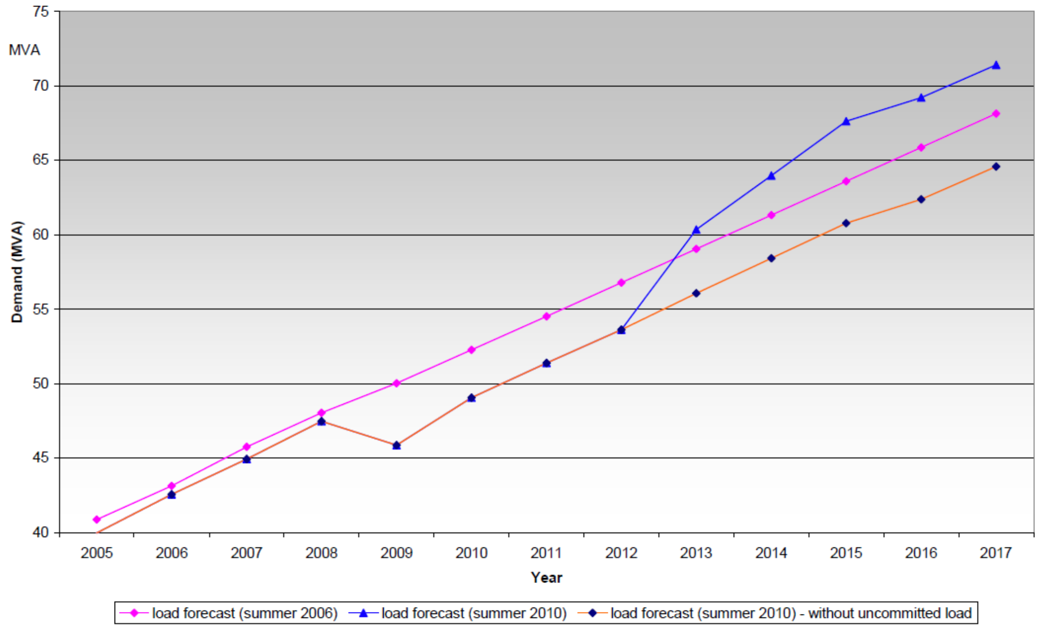
A8.3 DISCUSSION

The information provided for this review discussed the project at a high level with little useful supporting information – there were no technical study results or cost information. This lack of information makes it difficult to effectively assess the work program. However, it is recognised that, since Western Power has deferred the project, a full discussion on cost implications should not be necessary.

Western Power has indicated that in the most recent 10-year TNDP, based on current demand and generation scenario forecasts, the most cost effective solution is the installation of a 132 kV, 40 MVAr shunt capacitor bank at Busselton. Once this is installed, a second Picton-Busselton 132 kV line should not be needed until 2019-20. Given this medium to long term indicative time frame, it is difficult to understand why a shunt capacitor bank solution was not considered the more cost effective solution at the start of AA2, even allowing for the higher load forecast at that time.

This is apparent from Figure A8.1, which compares the APR 2010 combined load forecast for the Margaret River and Busselton areas with the 2006 forecast. This shows the potential for a block load in the region, which at the time was uncommitted and that we assume has not yet materialised. Because it is uncommitted, this block load has not been provided for in Western Power's current development plan. The figure shows that the difference between the two forecasts is due to a reduction in demand in 2009, which the current forecast assumes will only partly be recovered. Importantly, the 2010 forecast indicates a demand deferral of only one year on the earlier forecast. Given this, and looking at the latest proposed implementation date of 2019-20 (if a shunt capacitor bank is installed), it is evident that with the same reactive power solution, the implementation of the second line could have been deferred by several years even if the higher forecast had been used.

Figure A8.1: Combined demand in Margaret River and Busselton areas



Source: Additional notes: Transmission Capacity Expansion: AA2 expenditure review and the second Picton-Busselton 132kV line - DM#: 8815138

We therefore question the cost effectiveness of Western Power's proposed capex plan in its AA2 forecast.

The AA2 expenditure that Western Power considers meets NFIT requirements consists of internal labours, indirect cost allocations and flora, fauna and dieback assessments. Western Power has confirmed that this expenditure relates to the second transmission line rather than the capacitor bank now proposed.

The intention of allowing a portion of a project or program capex to be added to the capital base (in other words meeting NFIT) is to allow Western Power to recover a portion of a capital project that is currently being undertaken but is foreseen to be completed only after the end of the regulatory period. Since this project has been deferred and replaced entirely with another project because it has been assessed to not be the efficient solution, it follows that the expenditure initially invested does not meet the requirements of the efficiency test.

A8.4 CONCLUSION

Our analysis indicates that, given the information available to Western Power at the time, the second Picton-Busselton line included in the original AA2 capex forecast was unlikely to have been the most cost effective project to mitigate the potential under-voltage issue at Busselton. Now that the project has been deferred, we consider that Western Power's actual expenditure on the project does not meet NFIT requirements and should not be included in the AA3 opening capital base.

A9 RELIABILITY DRIVEN DISTRIBUTION PROJECTS

A9.1 BACKGROUND AND DESCRIPTION

Western Power's original capex forecast for reliability driven distribution projects was approximately $95 million. It is expected that total AA2 expenditure on the program will be approximately $34 million and Western Power considers that this all meets NFIT requirements.

The objective of the program was to ensure that Western Power met the distribution network service standard benchmarks in the AA2 access arrangement. The program included numerous small projects and from these, we selected three projects for detailed review. The total forecast expenditure of the three projects was just over $20 million. Only one of these projects, costing approximately $5.5 million was actually implemented. Nevertheless we reviewed the two projects that were not implemented to gain a better understanding of Western Power's governance and expenditure management procedures.

These projects we reviewed involved the planned deployment of automated and remote controlled switchgear (reclosers, load break switches, and ring main units) in the high voltage network during 2010-11 and 2011-12.

A9.2 DOCUMENTS PROVIDED

The documents listed in Table A9.1 were provided by Western Power for this NFIT review.

Table A9.1: Documents Provided for Reliability Driven Distribution Projects

Title	DMS#	Date
NFIT Compliance Summary for 2010/11 Metro Targeted Reliability Driven Automation	8868312	Nov 11
NFIT Compliance Summary for 2011/12 North Country Targeted Reliability Driven Automation	8871077	Nov 11
NFIT Compliance Summary for 2011/12 Metro Targeted Reliability Driven Automation	8856962	Nov 11
Network quality and reliability of Supply management plan 2009/2010	4497339v3	Jul 09
Planned DA Manual volume II - DQM User Guide for DA Stakeholders	4821340	Oct 09
Business Case - Targeted Reliability Driven 2011/12 Program	7628999	Aug 10
Spread sheets showing forecast and capital contributions during the AA2 period	-	-

Source: GBA

A9.3 EFFICIENCY TEST

Western Power deferred the projects that did not proceed either because the service standard benchmarks for the AA2 period were likely to be met even without the project or because the cost to improve reliability outweighed the benefit to Western Power from the expected reliability improvement as signalled by the AA2 SSAM incentive rates. Western Power has indicated that it will proceed with the planned work in AA3 if the incentive rate in the AA3 justifies it. This analysis is prudent and consistent with the behaviour that the SSAM is designed to encourage.

The third project involved expenditure in the AA2 of $6.19 million for targeted reliability driven automation in the Perth metropolitan area. This cost increased to $9.35 million at the time of the business case approval in December 2010[65]. By August 2011, the

65 It would appear that the business case of August 2010 includes a more detailed analysis of the required works for this asset category than that used for the forecast. We would expect this as it is unreasonable to expect the level of

reliability performance in the urban and rural short networks had reached target levels so some of the work included in the business case approval was deferred or cancelled. For this reason the actual expenditure on this project was only $5.56 million.

In preparing the business case Western Power investigated various options to ensure that its selected approach provided the greatest overall benefit in terms of reliability improvement and cost efficiency, as measured by $/SAIDI minute saved. We are satisfied that that materials and services for this project were procured in accordance with Western Power's procurement policy. Reliability projects in this program generally use materials that are stock items ordered through Western Power's standard stores and inventory control processes.

A major factor that influenced the selection of projects within this program was the quality of the actual reliability forecast information. It appears that Western Power's original forecast of its capex requirements to meet its reliability targets was based on a quantitative analysis that implicitly assumed existing management practices would continue. We think that a focus on network reliability driven by the SSAM may have resulted in better management, which has seen an improvement in service levels for little or no cost. Hence Western Power has been able to achieve its service standard targets at a much lower cost than anticipated at the time it prepared its AA2 capex forecast.

We consider that the program passes the efficiency test.

A9.4 SAFETY OR RELIABILITY TEST

Projects are included in this program on the basis of reliability analysis and forecasts indicating a possible breach of service standard benchmarks. If service standard benchmarks are breached, customers would not receive the service levels set out in the access arrangement and Western Power would not fully comply with the requirements of the Access Code.

Section 11.1 of the Access Code requires that Western Power must provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract. In the event Western Power fails to comply with Section 11.1, it will be in breach of the transmission and/or distribution licence. Given this, Western Power considers the achievement of the benchmarks to be mandatory.

We consider that the program passes the reliability test.

A9.5 CONCLUSION

We consider that the Western Power's expected AA2 capex on this program meets NFIT requirements.

individual project analysis in preparing an access arrangement forecast to be the same as that required for business case purposes.

A10 STATE UNDERGROUND POWER PROGRAM

A10.1 BACKGROUND AND DESCRIPTION

The objective of the State Underground Power Program (SUPP) is to improve the reliability and safety of the distribution network. This program was developed in response to major disruptions in the power supply in Perth and southern Western Australia brought about by severe storms. It is a partnership among the State Government, the Local Government Authorities and Western Power whereby the Local Government Authorities typically shoulder 50% of the total cost of a project while the State Government and Western Power contribute 25% each. The funding contributions from these parties are determined on the basis of total costs (capex and opex) and are netted off against opex first. Hence Western Power's contribution may appear to be higher than 25% of the total project capex.

The SUPP has two types of projects. The first is for the conversion of overhead distribution lines to underground distribution cables in suburban areas. This is the major residential project (MRP) component which accounts for approximately 96% of SUPP costs. The remaining 4% is for the localised enhancement project (LEP) component, which involves the beautification of urban gateways, scenic routes and tourism/heritage centres through the undergrounding of overhead lines.

The original AA2 forecast capex for this program was $63.61 million. However the program was subsequently expanded by the State Government for an additional cost of approximately $20 million.

A10.2 DOCUMENTS PROVIDED

The documents listed in Table A10.1 were provided by Western Power for this NFIT review.

Table A10.1: Documents Provided for the SUPP

Title	DM#	Date
State Underground Power Program (SUPP) Overview	8870079	Nov 11
Business Case - Project Execution Plan and Close Out Report – Wilson West Project	6312697v1, 6363669v2 and 6846741	Aug 09 Oct 09
Business Case - Project Execution Plan and Close Out Report – Mount Pleasant North Project	4094486, 4184097v1 and 5376478	Sept 07 Oct 07 Jul 09

Source: GBA

A10.3 DISCUSSION

Only the Western Power contribution to the cost of the program requires NFIT assessment as only this amount needs to be funded from the regulated revenue cap. Table A10.2 shows Western Power's forecast contribution in the different information that it provided for this review.

Table A10.2: Western Power's Forecast Contribution to the SUPP

Source:	SUPP Overview DM# 8870079	SUPP Overview DM# 8870079	D76384 Projects and Programs List	WP Response to PN 28	WP Response to PN 5
	Business Case ($ million, real 2011-12)	Actual/Expected ($ million, real 2011-12)	Actual/Expected ($ million, real 2011-12)	Actual/Expected ($ million, real 2011-12)	Actual/Expected in ($ million, real 2011-12)
Total	65.481	79.634	81.628	79.634	79.600
Capital Contributions		42.753	33.634*	42.754*	58.400
Balance meeting NFIT		36.881	47.994	36.880	21.200[1]

Source: Western Power
Note 1: Derived from values provided by Western Power

We are satisfied that the program as designed meets the net benefit test of the NFIT on the basis that, in designing the program, Western Power's contribution was assessed on the basis of its savings in the maintenance costs of an underground system. We also assume that the program installation costs were efficient on the basis that Western Power's governance procedures underpin the management and installation of the project.

The NFIT amount should be Western Power's contribution to the actual project cost, provided that this does not exceed the 25% Western Power is obliged to contribute under the terms of the program. We are concerned at the discrepancies in the different information sources provided, particularly in relation to the capital contribution amount. This makes it difficult to accurately determine what the NFIT amount should be. However, contributions that are due but have not been paid by the end of 2012 in respect of expenses that have been incurred during 2011-12 should be accrued for the purpose of determining the NFIT amount. While we are unable to determine the NFIT amount accurately, we would expect it to be of the order of $21 million.

A10.4 CONCLUSION

We are satisfied the Western Power's contribution to the actual cost of this program meets NFIT requirements, provided that this does not exceed the 25% that Western Power is obliged to contribute. For the purposes of determining the NFIT amount at the end of AA2, contributions that have not been received in respect of expenditure that is expected to be incurred by the end of the 2011-12 year should be accrued. We are unable to determine the exact NFIT amount but expect it to be of the order of $21 million.

We note the overspend of approximately $15 million was due to the expansion of the program by the State Government and should be taken in account when determining the NFIT amount.

A11 TRANSMISSION LINE RELOCATIONS

A11.1 BACKGROUND AND DESCRIPTION

The original AA2 capex forecast for transmission line relocations was approximately $29 million. Western Power has indicated that actual expenditure during AA2 is expected to be $15 million, of which it considers $1.9 million meets NFIT requirements.

Transmission line relocation activities are driven by requests from external parties, who are generally required to pay the full cost of the relocation through a capital contribution. Western Power considers that the global financial crisis was the biggest contributing factor to the reduced actual capex in AA2.

A11.2 DOCUMENTS PROVIDED

The documents listed in Table A11.1 were provided by Western Power for this NFIT review.

Table A11.1: Documents Provided on Transmission Line Relocations

Title	DMS#	Date
NFIT Compliance Overview for Transmission Line Relocations	8857110v1	Nov 11
Scope of work & risk assessment for e-bc business case estimates	5450290v1	Dec 09[1]
Project Approval Submission with business case	6461160v1	Sep 09
Letter in relation to Northern Terminal – East Perth/Belmont (NT – EP/BEL 81) 132kV Transmission Line: Relocation of poles 35 to 42, Alexander Drive and Reid Highway Intersection, Mirrabooka. Including attachments.	6332483v2	Aug 09
Project Management Plan – Project T0295166 – Relocate NT-EP/BEL Poles 35-42	7016134v1	Apr 10
Transmission Capital Program Management Branch – Close-Out Report - Relocate NT-EP/BEL Poles 35-42 – Project T0295166	7068149v1	Jul 10
Customer Solution Refund Authorisation Form	7288760v1	Jun 10
Response to ERA Information request PN19	8870854	Dec 11
User Guide for the Capital Contribution Procedure	3794822v4	Jun 07
Spread sheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA
Note 1: No document date provided, only a date at which the customer requires the service.

A11.3 DISCUSSION

Detailed cost estimates for each transmission line relocation project are prepared on a project by project basis using a bottom up costing approach. The estimate is then presented to the requesting party for approval.

The cost estimates are based on Western Power's standard design and construction practices, and design efficiency is further ensured through the business case review and sign-off process. Materials and services for each project are procured in accordance with Western Power's procurement policy.

We asked Western Power to clarify why any program costs should be funded from regulated revenue given that capital contributions are supposed to cover all costs.

> *As the transmission line relocations suite of projects are treated as a program, there are individual projects which are at each phase and gate of the works program governance framework at any given time. The amount of $1.902 million noted as meeting NFIT in a previous response represents the amount which has not yet been recovered through capital contributions where the reconciliation*

process is not yet complete. It is Western Power's intention to recover these costs in full from the customers concerned.

Western Power accounts for capital contributions on a cash basis. Outstanding contributions at the end of AA2 are routinely included in the opening AA3 capital base. When the capital contribution is received during AA3, there will be a negative capex adjustment, which should ensure that the contribution is returned to customers through the IAM.

A11.4 CONCLUSION

The NFIT amount for this project is Western Power's estimate of the outstanding capital contributions at the end of AA2. As Western Power's policy is to fully recover the costs of transmission line relocations through capital contributions, the NFIT amount should be recovered during AA3 and returned to customers through the IAM. In the event that a line relocation does not proceed, or capital contributions are unable to be recovered from the party requesting the relocation for any reason, capex incurred by Western Power will remain in the capital base and be funded by customers.

A12 TRANSMISSION SCADA AND COMMUNICATIONS – SYSTEM OPERATIONS CAPEX

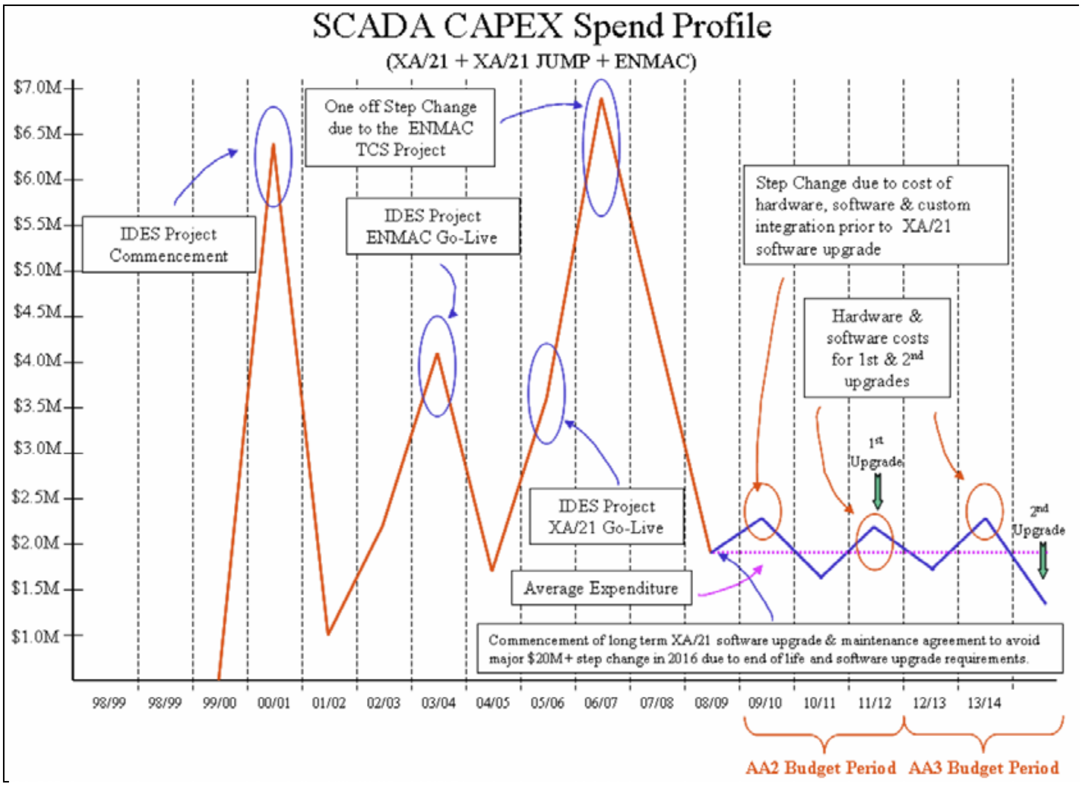
A12.1 BACKGROUND AND DESCRIPTION

The original AA2 capex forecast for transmission system operations capex was $12.02 million. Western Power has indicated that $8.97 million is expected to be spent on this program over AA2 and considers that all this expenditure meets NFIT requirements.

A large power system such as the south west interconnected system (SWIS) requires a central control function that monitors and mitigates security risks by taking action where required. This central control function works in conjunction with the real time generation market operations which are separately funded under the wholesale electricity market (WEM) Rules. These control functions are essential to ensure compliance with the Technical Rules and WEM Rules.

The system operations capex project includes a long term 6 year upgrade and maintenance program with GE Energy as software vendor. The project comprises software and hardware updates to the existing XA/21 energy management system which is used for the required central control function. Western Power considers that its strategic vendor partnership with GE Energy will assist with the upgrade process and reduce overall costs and avoid potential large capex step changes in the future. This long term contract, requiring annual payments, should also reduce the generally lumped expenditure trend experienced for typical SCADA systems as can be seen in the historic Western Power expenditure in recent years as depicted in the Figure A12.1 below.

Figure A12.1: Long Term Spend Profile on Transmission System Operations Capex



Source: Western Power document DMS#5205709v10

Two system upgrades are planned over the 6 year period which is expected to improve the system through the integration of Western Power's own requirements into the core XA/21 energy management system solution.

A12.2 DOCUMENTS PROVIDED

The documents listed in Table A12.1 were provided by Western Power for this NFIT review.

Table A12.1: Documents Provided on Transmission SCADA and Communications – System Operations Capex

Title	DMS#	Date
NFIT Compliance Summary for 199203 System Operation CAPEX	8837673	Dec 11
Project Information Sheets - Numerous	4322723v6	-
Financial Evaluation Model – T0321290 (Print Copy)		Dec 11
Software Upgrade Agreement	6165140v1, 5588584v3	-
Schedule 1 – Insurance	5506332v3	-
Schedule 2 – Scope of works	5504811v8	-
Schedule 3 – Technical Requirements	5504827v10	-
Schedule 4 – Western Power Policies	5506343v2	-
Schedule 5 – Commercial Terms	5506353v7	-
Schedule 6 – Delivery Schedule	5528546v3	-
Schedule 7 – Hardware and Software Requirements	5578854v3	
Managing Director – Cover Sheet – Project Approval Submission	5205718v4	2009
Business Case – 6 year XA/21 Long Term Software Upgrade and Maintenance Support Agreement	5205709v10	2009
Project Management Plan – XA/21 Upgrade	6166533v1	Jun 09
Spread sheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A12.3 EFFICIENCY TEST

Western Power has indicated that services for this project could only be supplied by a sole source supplier and that a waiver from competition was therefore obtained from the Group Commercial Branch. GE Energy is the only supplier of the XA/21 transmission energy management system.

Three options were assessed in the business case: do nothing, entering into a long term vendor contract (the preferred option) or delaying or postponing the work until a future date. Western Power believes that the two options that were not preferred would result in an expenditure step change in 2016 in the order of $20 million and therefore that the long term contract with GE Energy will provide the best value for money. No investigation into alternative solutions formed part of the options analysis in the business case but it is assumed that this would not be practical as the XA/21 transmission energy management system has already been implemented. Even so, it would have been useful if the overall costs and benefits of the GE Energy solution had been compared with competitor offerings.

The main driver for the project was to reduce the potential for a lumped capex step change of uncertain magnitude when a system upgrade was required. To highlight this point, Western Power compared its estimated expenditure of $12.02 million for the long term contract with an estimated figure of $20 million for a full system implementation in 2016.

It is not clear how the business case estimated cost of $20 million for a full system implementation in 2016 was derived. Furthermore the basis for the implied business case assumption that both solutions would require the same expenditure after 2016 is unclear. For example, it is not clear if the long term contract upgrading process will not eventually lead to a requirement to upgrade the full system anyway and therefore increase the overall life cycle cost drastically[66].

Notwithstanding the above concerns over the business case options analysis, we realise that SCADA an IT systems require maintenance and upgrading and that the timeframe for such expenditure is much shorter than the typical network asset standard life due to rapid technological advances. We also acknowledge that uncertainty as to what might happen after 2016 is not, of itself, a reason for not making a decision as to how best to proceed. Overall, we consider that the program passes the efficiency test.

A12.4 SAFETY OR RELIABILITY TEST

Western Power is required under the WEM Rules to meet requirements for continuous power system monitoring and control. When this monitoring and control function fails it can lead to customers not receiving the quality of supply to which they are entitled.

Based on the above, we consider that the program passes the reliability test.

A12.5 CONCLUSION

We consider that the capex spent on this program meets NFIT requirements.

We understand that the XA/21 energy management system is used primarily for controlling operation of the power system under the WEM rules. In Section 7.6 we raise the issue of whether this and other power system operations hardware and software should be funded form transmission revenue or by the independent market operator (IMO) and noted that the boundary between Western Power and IMO assets had not been defined. We understand that this system has historically been considered a transmission asset and our conclusion is predicated on the assumption that this situation will continue.

[66] There is significant uncertainty over what will happen after 2016. It may be that the vendor changes is offering or stops supporting the product.

A13 OVERLOADED TRANSFORMER AND LOW VOLTAGE CABLE REPLACEMENT

A13.1 BACKGROUND AND DESCRIPTION

The program is ongoing from AA1 and involves the proactive replacement of distribution transformers with capacity greater than 100 kVA and their associated low voltage cables that are forecast to experience high loading (more than 135%). The program objective is to minimise unplanned interruptions due to overload. To date the program has been very effective.

Most of the time these transformers operate well within their design ratings and potential overloading problems are therefore unlikely to be discovered through routine inspection. The program of proactive replacement was commenced after a very hot summer in 2004 when there were a significant number of unplanned distribution transformer failures due to overload. Western Power now proactively predicts maximum distribution transformer loads using its load forecasting analysis tool. This uses customer consumption data, peak summer feeder loads and other asset information to calculate the loads predicted to occur on its distribution transformers. When a potential overload is found, this is confirmed by field investigation and, where necessary, the transformer and its associated low voltage circuits are scheduled for upgrade under the program.

The forecast AA2 capex for the program was $29.25 million. Western Power now expects to spend $28.25 million during AA2, all of which it considers meets NFIT requirements.

A13.2 DOCUMENTS PROVIDED

The documents listed in Table A13.1 were provided by Western Power for this NFIT review.

Table A13.1: Documents Provided on the Overloaded Transformer and Low Voltage Cable Replacement Program

Title	DM#	Date
NFIT Compliance Summary for Overloaded Transformer & LV Cable Replacement	8846152	Nov 11
Business Case for Overloaded Transformer Replacement Program AA2	7329190	Aug 10
Business Case for Distribution Transformer Replacement from 2009/2010 to 2011/2012	6867347	Aug 10

Source: GBA

A13.3 EFFICIENCY TEST

In the business case Western Power considered the following three options to mitigate the risk of distribution transformers failing on overload:

1. Proactively replacing overloaded assets;
2. Retain existing assets and provide emergency response generators; and
3. Retain the existing assets and replace them reactively when they fail.

Of these three options, the proactive replacement of overloaded transformer and LV cables provides all the required outcomes at the least cost.

The materials and services for this program were procured in accordance with Western Power's procurement policy. In addition the program was governed by Western Power's capital approval and delegated financial authority procedures.

Western Powers AA2 access arrangement information forecast the need to replace 501 transformers and associated cables at $29.25 million. The approved business case estimated a total of 453 transformers and associated cables at $30.80 million would need to be replaced. Western Power now expects to replace 426 transformers during AA2 for a cost of $28.25 million. Table A13.2 provides high level unit costs derived from the quantities and total cost for each scenario and shows that even though the actual unit rates appear lower than the unit rates presented in the business case, it is about 13.6% higher than the original AA2 forecast.

Table A13.2: High Level Unit Cost Analysis ($ million, real 2011-12)

	Quantity	Cost	Unit Cost
AA2 Forecast Estimate	501	29,250	58.38
Business Case	453	30,800	67.99
Actual AA2	426	28,250	66.31

The program consists of small projects, each of which is unique and requires an individual design. The scope of the program is based on load data for the previous summer and therefore is updated annually. For this reason, the total cost of the program or even the unit costs are somewhat difficult to predict.

Western Power's expected AA2 program cost does not exceed either the original AA2 capex forecast or the business case cost estimate. A total of 27 transformer replacements have been deferred due to competing resource priorities.

We consider that the program meets the requirements of the efficiency test.

A13.4 SAFETY AND RELIABILITY TEST

The project will address reliability issues in the network through the reduction of unplanned transformer and cable failures. We therefore consider that it meets the requirements of the safety and reliability test.

A13.5 CONCLUSION

We consider that the program meets the requirements of the NFIT.

A14 DISTRIBUTION CONDUCTOR REPLACEMENT

A14.1 BACKGROUND AND DESCRIPTION

Western Power's original AA2 forecast capex for the replacement of distribution conductors in moderate and low fire risk zones was approximately $39.62 million. It expects to spend approximately $28.53 million on the program over AA2 and considers that all this capex meets NFIT requirements.

This program involves the ongoing replacement of unserviceable and damaged overhead conductors in moderate and low fire risk zones. It runs in conjunction with the bushfire mitigation wires down program which focuses on extreme and high fire risk zones. The objective of the program is to reduce the extent of unassisted wires down incidents.

The program consists of a number of small projects, each with an individual scope of works. There are instances where an existing overhead conductor is replaced by an underground cable due to the level of risk identified. The scope of work assumed for the original AA2 forecast included the replacement of 105 km of conductor, of which 18% would be replaced with underground cables.

As a result of improvements to the inspection process and a change from reactive to proactive maintenance, the business case dated June 2010 identified an estimated quantity of 540 km of conductor requiring replacement with an underground cable replacement rate of less than 2%. With this scope change, the business case requested expenditure was $38.40 million. The estimated quantity of 540 km was based on an actual 393 km of identified conductor requiring replacement an estimate of the amount of additional conductor likely to require replacement.

Western Power has indicated that, due to funding constraints, not all the conductors identified for replacement in the first two years of AA2 were replaced. However, from the latest F1 forecast, Western Power estimates that 520km out of the 540km identified in the business case will be replaced over AA2 at a total expenditure of $28.53 million.

A14.2 DOCUMENTS PROVIDED

The documents listed in Table A14.1 were provided by Western Power for this NFIT review.

Table A14.1: Documents Provided on the Distribution Conductor Replacement Program

Title	DMS#	Date
NFIT Compliance Summary for Distribution Carrier Replacement	8875789	Dec 11
Distribution Design Engineering Design Information Manual	4678720	Oct 10
Business Case for the Replacement of Distribution Carrier 2009/10 to 2011/12 in 'Moderate' and 'Low' Fire-Risk Zones	6876595	Jun 10
Scope of Work - Conductor Replacement – North Country – Port Gregory - GTN/Z226	8198127	May 11
Scope of Work - South Country Nanarup - Two Peoples Bay Road Kalgan Conductor Replacement – HV Network Tp1 To Tp135 Alb 514.0 Willyung Feeder	7509498	Oct 10
Spread sheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A14.3 EFFICIENCY TEST

Prior to July 2010, conductor condition assessments were done as part of the routine wood pole inspection program. However the data collected was not sufficiently consistent and comprehensive and did not provide a reliable view of conductor condition. Because of this, Western Power commenced a "bundled" inspection program in July 2010, which is expected to provide improved conductor condition information over time. Given that the improvement in the process came after the completion of the business case, the basis for the selection of 540 km overhead conductor cables for replacement is unclear. However, we assume that only conductors that have reached the end of their serviceable life replaced over the AA2 period.

When compared with the actual replacement costs incurred during AA2, the original forecast of $39.62 million was high, given that it provided for the replacement of only 105 km of overhead conductor, even after allowance is made for the high level of replacement with underground cable provided for in the forecast. The expected actual cost of $28.530 million for the replacement of 520 km of conductor is much more efficient than implied by the original forecast. The program has a high labour component and is delivered using Western Power's own internal resources and those of its distribution delivery partners. The project business case considered a number of options and the lowest cost option was selected.

All materials and equipment required to undertake this program were sourced in accordance with Western Power's corporate and procurement policies.

We consider that the program meets the requirements of the efficiency test.

A14.4 SAFETY OR RELIABILITY TEST

This program of work is directed at reducing the public safety hazard and risk of fires resulting from overhead conductor failure and is therefore targeted at improving and maintaining the safety of the network in accordance with the Electricity Regulations 2001 (Supply Standards and System Safety).

The program also reduces improves system reliability by reducing the risk of unplanned faults and should have an impact on costs due to the reduction of emergency fault response requirements.

We consider that the program passes the safety or reliability test.

A14.5 CONCLUSION

We consider that the program meets the requirements of the NFIT.

A15 CANNINGTON TERMINAL STATION TRANSFORMER REPLACEMENT

A15.1 BACKGROUND AND DESCRIPTION

Western Power's original AA2 forecast capex for the replacement of five 132/66/22 kV 45 MVA power transformers at Cannington terminal station with three 100 MVA power transformers was $8.00 million. Approximately $6.60 million is expected to be spent on this project during AA2 and Western Power considers that all this expenditure meets the requirements of the NFIT. The total cost of the project, as estimated for the business case, is approximately $19 million to be incurred over AA2 and AA3. The AA2 under-expenditure will now be incurred during AA3.

Western Power has identified through its transformer condition monitoring program that the three older transformers at Cannington Terminal substation are in poor condition with an elevated risk of failure. These transformers are around 50 years old and require immediate replacement.

The demand forecast for the area supplied by the substation indicates that the load will increase to about 180 MVA. If the load increases beyond that level, measures other than the addition of transformer capacity at Cannington will be required. Western Power investigated seven options to mitigate the risks associated with failure of the three transformers identified as being in poor condition. These options included refurbishment of the transformers and the replacement of the transformers with new units of various sizes. The least cost option was selected, which was the replacement of all five existing transformers with three new 100 MVA units. The two 45 MVA transformers in good condition will be redeployed to another substation.

A15.2 DOCUMENTS PROVIDED

The documents listed in Table A15.1 were provided by Western Power for this NFIT review.

Table A15.1: Documents Provided on the Cannington Terminal Station Transformer Replacement Program

Title	DMS#	Date
NFIT Compliance Summary for Cannington Terminal	8856707	Nov 11
Business Case for the Replacement of Terminal Power Transformers (Cannington Terminal)	6981419	Mar 11
Board Paper - Replacement of Terminal Power Transformers (Cannington Terminal)	7885475	Apr 11
Project Management Plan - Project T0278258	7156269v1	Nov 11
Spread sheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A15.3 EFFICIENCY TEST

The business case considered several options and Western Power selected the least cost option as its preferred solution. It utilised its financial evaluation model to assess all options.

All materials and equipment for the project are sourced in accordance with Western Power's corporate and procurement. The transformers are supplied under a period contract with a preferred vendor. In our view the cost of the three new 100 MVA transformers was reasonable.

We consider that the program passes the efficiency test.

A15.4 SAFETY OR RELIABILITY TEST

This project mitigates a high risk of transformer failure at Cannington terminal station which would reduce the level of security at the substation and increase the risk of a loss of supply. Based on the condition of the transformers, we think the actions being taken by Western Power are prudent.

We consider that the program meets the requirements of the safety or reliability test.

A15.5 CONCLUSION

We consider that the project meets the requirements of the NFIT.

A16 DISTRIBUTION WOOD POLE REINFORCEMENT

A16.1 BACKGROUND AND DESCRIPTION

The original AA2 capex forecast for this program was $37.4 million. Western Power now expects to spend $39.7 million[67], which is approximately 6% more than the forecast amount. It considers that all this capex meets NFIT requirements. The original AA2 forecast provided for the reinforcement of estimated [redacted] wood poles at an average unit cost of roughly [redacted]. The actual unit cost is now expected to be approximately [redacted].

The need for the reinforcement of wooden poles stems from the outcome of EnergySafety's 2008 Audit which resulted in an Order, issued in 2009 under Section 18B of the Energy Coordination Act 1994, whereby Western Power is required to reinforce or replace all unsupported rural poles that do not comply with specified strength requirements[68]. The pole reinforcement work will reduce unassisted pole failure rates (Western Power's current failure rate is high compared to the industry average)[69], reduce business risk, reduce emergency repair costs and potentially avoid SSAM implications.

Western Power estimates that its pole failure rate, which was 1.87 pole failures per 10,000 poles in 2008-09, should reduce to 1.35 pole failures per 10,000 poles per annum after implementation of the pole reinforcement program.

A16.2 DOCUMENTS PROVIDED

The documents listed in Table A16.1 were provided by Western Power for this NFIT review.

Table A16.1: Documents Provided on the Distribution Wood Pole Reinforcement Program

Title	DMS#	Date
NFIT Compliance Summary for Distribution Pole Reinforcement	8834335v1	Nov 11
Business Case for the Reinforcement of Distribution Wood Poles 2009/10 to 2011/12	6940516	Jun 10
Board Papers		2009 and 2010
NFIT Evaluation Report for the Wood Pole Management Program	8567168v2	6 Sep 11
Wood Pole Failure Prediction Model	6860517v1	Feb 10
Wood Pole Asset Management Plan 2011-17	8172520(rev 1.1)	11 Nov 11
Wood Pole Inspection Procedure	5449945	May 11
Wood Pole Management Program	Mercor Consulting Pty Ltd	Sep 11
Network Management Plan 1 July 2011 – 30 June 2017		Aug 11
Distribution Poles and Related Data	709305	Nov 09
Pole Inspection and Treatment	3271852	Dec 10
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

67 The forecast investment has been updated with the F1 forecast.

68 Energy Safety's issued Order 01-2009 requires Western Power to replace or reinforce all unsupported rural poles that do not comply with ENA C(b) 1 – 1999 using maximum wind pressures based on wind speeds with a five year occurrence.

69 The Business Case states that the current industry average failure rate is 0.435 poles per 10,000 per annum whereas Western Power's failure rate is 1.87 poles per 10,000 for 2008-09.

A16.3 EFFICIENCY TEST

Approximately 18,000 poles were reinforced in the first two years of AA2 and, based on its F1 forecast, Western Power expects that a further 16,000 reinforcements will be completed by the end of the AA2 period. With a total of [redacted] pole reinforcements planned for AA2 the average unit cost will be less than [redacted] per pole which is less than the [redacted] per pole used for the AA2 forecast. Western Power has indicated that the reduction in unit rates was made possible by volume discounts from key suppliers.

Western Power is endeavouring to achieve efficiencies in works delivery across the distribution network through its balanced portfolio strategy and by using performance based contracts with its distribution delivery partners.

We note that EnergySafety considers that pole reinforcement is a cost effective way of reducing the risk of unassisted pole failure. Western Power has applied different pole reinforcement solutions over time and is continually considering new approaches to improve the effectiveness of the program. The four steel reinforcement method is currently used.

We consider that this program meets the requirements of the efficiency test.

A16.4 SAFETY OR RELIABILITY TEST

Unassisted pole failures are a risk to the safety of the network. We are satisfied that this program meets the requirements of the safety or reliability test.

A16.5 CONCLUSION

We consider that the program meets the requirements of the NFIT.

A17 NEW FEEDER AT SOUTHERN RIVER ZONE STATION

A17.1 BACKGROUND AND DESCRIPTION

The original AA2 forecast for the new distribution feeder at Southern River (SNR) zone substation was approximately $1.27 million. The amount actually spent on the project during AA2 was $2.32 million; an overspend of 83%. Western Power considers that the full amount actually incurred meets NFIT requirements. In addition, further work with an estimated cost of $546,000 will be undertaken on this project during AA3, increasing the overspend to more than 100%.

This project entails the creation of a new distribution feeder associated with the installation of a new 132/22 kV transformer at Southern River and includes the upgrading of conductors with insufficient fault rating. The business case showed that the peak demand for the SNR, Canning Vale (CVE) and Gosnells (G) zone substations would exceed their rating under contingency operating conditions so capacity expansion was needed. Western Power has stated that five of the seven existing SNR feeders are projected to be operating at above 80% of their rated feeder capacity during peak periods in 2012-13. Moreover, during summer peak periods, the high loading of the SNR distribution feeders as well as the lack of available capacity from neighbouring substations will limit the quantity of available distribution transfer capacity and therefore increase the risk of load shedding in the event of network faults.

A17.2 DOCUMENTS PROVIDED

The documents listed in Table A17.1 were provided by Western Power for this NFIT review.

Table A17.1: Documents Provider for New Feeder at Southern River Zone Substation

Title	DMS#	Date
NFIT Compliance Summary for Southern River Install a new feeder	8909617	Dec 11
Business Case - Southern River Capacity Improvements - Project Number T0122727, N0255871, N0256642, N0303899	7887300	Jan 11
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A17.3 EFFICIENCY TEST

Western Power has stated that the original AA2 forecast for this project was determined before a proper scope or project timing was developed and this is the reason for the over expenditure. The business case for the overall capacity expansion in the Southern River area was approved in March 2011, indicating that project plans were only finalised at a late stage in AA2.

The business case for this project considered a range of options. However the options available to Western Power were limited because of the geographical separation of some feeders due to the Tonkin Highway. From these options, it is assumed that Western Power selected the least cost option as the preferred solution.

Western Power has indicated that in order to determine the most efficient and effective approach for the program of work, the in-house PowerFactory distribution system analysis package was used. Moreover, the Cymcap (Cable Ampacity Calculation) analysis package was utilised to establish the optimal cable ratings. Western Power has confirmed that all materials and equipment required to undertake this program are sourced in accordance with Western Power's corporate and procurement policies.

Having reviewed the documents provided, we accept that the main reason for the over-expenditure on this project compared to the original AA2 forecast was a lack of understanding of the full scope of work required when the AA2 forecast was prepared. We consider that the program passes the efficiency test.[70]

A17.4 SAFETY OR RELIABILITY TEST

Based on the load demand forecast for the Southern River area, Western Power is endeavouring to finish all major transmission works in 2011-12 so the additional capacity to be available for the 2012-13 summer peak load.

This project was undertaken in response to the need to maintain network reliability given the increasing load demand. It has been assessed by Western Power that the distribution network will no longer be adequate to maintain the required network security as set out in the Technical Rules[71].

Given this, we consider that the project meets the requirements of the reliability test.

A17.5 CONCLUSION

We consider that Western Power correctly applied its governance procedures for this project, which should have delivered efficient design and cost outcomes. The main issue appears to have been a lack of understanding of the full scope of work required when the AA2 forecast was prepared. This led to an under-estimate of the project cost.

We consider that the project capex meets NFIT requirements.

[70] We did not undertake a more detailed cost efficiency analysis for the selected solution due to time constraints and the unavailability of more detailed information. We do not expect that a detailed analysis will result in material changes to the conclusions of this review.

[71] Technical Rules clause 2.5.3.2(b) and 2.5.4.3(b)2(A).

A18 NEW FEEDERS AT WANNEROO ZONE SUBSTATION

A18.1 BACKGROUND AND DESCRIPTION

The business case for this project shows that, without reinforcement, the peak demand for the Mullaloo (MUL), Wanneroo (WNO) and Joondalup (JDP) zone substations will exceed their rating under contingency operating conditions. This review relates specifically to the creation of three new distribution feeders at Wanneroo zone substation associated with the installation of a new 132/22 kV transformer at Joondalup substation.

Wanneroo substation has three transformers which in summer of 2009-10 had actual demands that exceeded 95% of their nameplate rating. The peak demand on these transformers is forecast to exceed their rating in summer of 2012-13. Given the peak demand forecast for the Wanneroo and Joondalup areas, Western Power is endeavouring to finish all transmission and distribution works by November 2012 in order for the additional capacity to be available for the summer of 2013, which is the time it was forecasted that the transformer rating will be exceeded.

The original AA2 forecast for this project was approximately $584,000. Western Power has indicated that about $1.25 million was actually spent during AA2 period and it considers that all expenditure meets NFIT requirements. Moreover, Western Power has indicated that the bulk of the work for this project will be undertaken in AA3, which is estimated to cost an additional of $4.43 million.

The original forecast for this project was estimated before a proper project scope was prepared. The business case for the overall capacity expansion around the MUL, WNO and JDP substations was approved only in June 2011, indicating that project plans were only finalised at a late stage in AA2.

A18.2 DOCUMENTS PROVIDED

The documents listed in Table A18.1 were provided by Western Power for this NFIT review.

Table A18.1: Documents Provided for New Distribution Feeders at Wanneroo Substation

Title	DMS#	Date
NFIT Compliance Summary for Joondalup 2nd Transformer Distribution Works	8907562	Dec 11
Business Case - Installation of a New 132/22 kV Transformer at Joondalup substation - Project Number T0201539, N0277440	8115062	May 11
Spreadsheets showing forecast and capital contributions during AA2 period	-	-

A18.3 EFFICIENCY TEST

The business case for this project considered several options and Western Power selected the least cost option as its preferred solution. Furthermore, Western Power undertook a network planning study to investigate the capacity shortfall in the affected areas[72].

While the actual capex incurred in AA2 was substantially higher than the forecast, it would appear that it was mainly due to the rescheduling of work between the AA2 and AA3 periods rather than scope changes. While this is the case, Western Power has stated that all materials and equipment required to undertake this project are sourced in accordance with Western Power's corporate and procurement policies. Given this, and

[72] *Transformer Capacity Shortfall in the cluster of Mullaloo, Joondalup and Wanneroo 132/22kV Zone Substations.* DM# 7621398

the fact that the overall project cost does not appear to be unreasonable, we consider that the project satisfies the efficiency test[73].

A18.4 SAFETY OR RELIABILITY TEST

This project was undertaken in response to the need to maintain network reliability with the increasing peak demand. It has been assessed by Western Power that, without the project, the distribution network would no longer be adequate to maintain the required network reliability as set out in the Technical Rules[74].

Given this, we consider that the project meets the requirements of the reliability test.

A18.5 CONCLUSION

Even though the actual project expenditure in AA2 was higher than forecast, this was due to the rescheduling of work rather than an error in the forecast. We found no significant issues with project governance that note all materials and equipment were sourced in accordance with Western Power's corporate and procurement policies. This should have led to efficient outcomes.

We consider that the project capex meets NFIT requirements.

[73] We did not undertake a more detailed cost efficiency analysis for the selected solution due to time constraints and the unavailability of more detailed information. We do not expect that a detailed analysis will result in material changes to the conclusions of this review.

[74] Technical Rules clause 2.5.3.2(b) and 2.5.4.3(b)2(A).

A19 NEW FEEDER AT CLARKSON ZONE SUBSTATION

A19.1 BACKGROUND AND DESCRIPTION

Western Power's original AA2 forecast for the installation of a new 22 kV feeder at Clarkson zone substation to offload the highly loaded Yanchep Substation YP502 feeder was $1.42 million. Western Power has indicated that approximately $1.463 million was spent on this project over AA2 and it considers that all expenditure meets NFIT requirements.

Due to increasing residential load in the northern suburbs of Clarkson, Butler and Jindalee, Western Power considered that there was an increasing risk to public safety and reliability unless mitigating measures were undertaken. There was a 30% increase in peak demand on the Yanchep YP502 feeder over the 2007-09 summer periods, mainly due to new subdivision developments superimposed on the underlying demand growth in the area. This increased demand has reduced the availability of distribution transfer capacity which in turn has increased the risk to network reliability. After a number of different options were assessed, Western Power selected what it considered the optimal solution, which was the creation of a new 22kV distribution feeder from Clarkson substation to offload the highly loaded Yanchep Substation YP502 feeder.

We note that the business case dated March 2010 indicated a total project expenditure of $2.14 million based on an assumption that the ground was 100% rock. It was later found that the ground condition is only 70% rock, which reduced the actual project expenditure to an amount very close to the original AA2 forecast. We are a little surprised at this inaccuracy since Western Power procedures require sufficient geotechnical testing to be undertaken to establish ground conditions with sufficient accuracy to permit cost estimates to be prepared with the level of accuracy required for business case submission. It may be that extensive geotechnical testing was not considered warranted given the relatively small project cost.

A19.2 DOCUMENTS PROVIDED

The documents listed in Table A19.1 were provided by Western Power for this NFIT review.

Table A19.1: Documents Provided for New Feeder at Clarkson Zone Substation

Title	DMS#	Date
NFIT Compliance Summary for Clarkson Install 1 New Feeder (Offload YP502)	8905282	Dec 11
Business Case - N0273154 - Clarkson – Install New Feeder (Offload YP502)	6551614v20	Mar 10
Spread sheets showing forecast and capital contributions during AA2 period	-	-

Source: GBA

A19.3 EFFICIENCY TEST

The business case for this program considered a range of options, including demand side management. It would appear that Western Power selected the least cost option as its preferred solution. All materials and equipment required to undertake this program were sourced in accordance with Western Power's corporate and procurement policies. The correct application of Western Power's expenditure governance procedures should ensure efficient design and cost outcomes. Given this, and the fact that the overall cost does not appear unreasonable, we consider that the project satisfies the efficiency test.[75]

A19.4 SAFETY AND RELIABILITY TEST

The Technical Rules[76] require Western Power to adhere to specific network reliability standards in order to ascertain that customers receive an acceptable quality of supply. With the increasing peak demand, Western Power's distribution network became inadequate to meet these reliability standards and therefore, the capacity expansion program was required. We consider that the project satisfies the reliability test.

A19.5 CONCLUSION

We consider that the project capex meets NFIT requirements.

75 We did not perform a more detailed cost efficiency analysis for the selected solution which would have required more time to obtain more detailed project cost information and would have resulted in very minor non-material changes relating to this particular project only, if any.

76 Technical Rules clause 2.5.3.2(b) and 2.5.4.3(b)2(A).

APPENDIX B

REVIEW OF SELECTED AA3 PROJECTS AND PROGRAMS

B1 OUTAGE DURATION REDUCTION CAPEX

B1.1 BACKGROUND AND DESCRIPTION

In its AA3 capex forecast, Western Power has provided a total of $41.4 million for this program; $10.0 million in 2012-12 and approximately $7.85 million in each of the following four years. The objective is to reduce the number of consumer supply outages lasting longer than 12 hours.

The driver for this program is the Supply Code.

- Section 12 of the Supply Code requires that any consumer connected to the network must not experience an interruption lasting more than 12 hours more than once every ten years. The section further requires Western Power to remedy the cause or causes of the problem where it believes that this standard will not be met.

- Section 19.1 of the Supply Code provides that any consumer experiencing an interruption lasting longer than 12 hours is entitled to a compensation payment of $80 on application to Western Power. Compensation payments cost Western Power approximately $1.55 million in 2010-11. (See Section 10.6.4).

The program is designed to reduce the number of consumers connected to the network that experience supply interruptions lasting longer than 12 hours.

B1.2 DISCUSSION

Western Power developed this program after reviewing the practicality of completing the requirements of the Supply Code. Salient points from this review were that:

- Section 13 of the Supply Code requires Western Power to meet specified SAIDI targets "as far as is reasonably practical". However the SAIDI targets are not aligned with the corresponding service level benchmarks or SSAM targets in the access arrangement.

- Unlike the access arrangement, or similar legislation in other jurisdictions, the Supply Code does not provide for exclusions. In other jurisdictions, similar regulations explicitly exclude interruptions caused by events outside the service provider's control and generally exclude interruptions occurring on major event days when the service provider's ability to respond to severe storms and the like is under stress.

- Western Power has indicated that the root cause of outages lasting more than 12 hours is the deferred repair of faults that occur in the late afternoon, evening or early hours of the morning. This is sanctioned by Western Power's work practices for fatigue management in accordance with the Occupational Health and Safety Act 1984. Typically the fault or hazard is isolated through manual switching, then the following morning safely repaired, patrolled and customers restored.

- Proposed solutions to address the issue of prolonged supply interruptions without compromising safety include:

    - Remote detection and isolation of the faulted section of the line to provide more daylight hours for repair and restoration; and

    - Interconnection and smaller remotely switchable sections to reduce the number of customers without power overnight.

We consider that Western Power's analysis of the Supply Code's requirements is comprehensive. We agree that some Supply Code requirements conflict with the access arrangement and this makes it difficult for Western Power plan to achieve full compliance. We also consider that the cost to achieve full compliance would be excessive.

Nevertheless, most jurisdictions acknowledge that it is important to minimise the incidence of very long power interruptions, particularly those that occur when the network service provider's ability to respond is not under stress, and that it is reasonable for expenditure to be allocated to make sure that the number of excessively long customer interruptions is managed.

It appears that the capex will be allocated to the provision of the following solutions:

- Installation of remote fault detection devices and remote controlled switches. This will allow faults to be located more quickly and supply restoration to be faster. The hope is that with faster fault location it will be possible for more faults to be repaired before nightfall and fewer customers left off supply overnight.

- Installation of additional manually operated switches and interconnections between feeders. This will reduce the size of switching sections and hence the number of customers that may need to be left without power overnight as a result of a particular fault.

The criteria that Western Power plans to use to determine network locations where these measures are to be applied is not clear, except that feeders where extended outages have occurred in the past will be targeted. Western Power has still to prepare its business case for the program and these issues will presumably be addressed in detail in that document. However, the above solutions are commonly used in the industry to reduce SAIDI and SAIFI and we would expect that the program could well have an impact on Western Power's measured reliability service levels.

We consider however, that the effectiveness of the program in meeting its primary objective will nevertheless be limited in that it will not directly address the main cause of extended outages, which is the practice of leaving power off overnight so that repairs can be undertaken in daylight. Western Power has advised that:

> *incidents occurring late in the afternoon or evening are made safe and isolated to be addressed at first light the following day due to OH&S fatigue management policies*[77]

It appears that Western Power does not routinely offer a 24 hour supply restoration service. While this may once have been standard industry practice, our understanding is that most distribution network service providers now provide a 24 hour fault repair (as distinct from location and isolation) service, where every effort is made to restore supply as quickly as possible, even during the hours of darkness, unless working conditions are demonstrably unsafe.

We understand that in the eastern states field crews may be asked to work for up to 16 hours without a rest in order to ensure that supply is restored, and repair crews will be called out overnight as necessary. This is also the usual practice in New Zealand.

We note that Western Power's own web site states:

> *…during an emergency or crisis, and in the aftermath, Western Power crews work 16 hour shifts on rotation to ensure restoration work continues 24 hours a day*[78]*.*

It is not clear to us why, if Western Power field crews will work 16 hour days during an emergency or crisis, occupational health and safety requirements prevent crews working extended shifts to restore supply when an emergency does not exist.

B1.3 CONCLUSION

77 DM# 8834875.

78 http://www.westernpower.com.au/customerservice/interruptionsrestoration/FAQs_and_further_information.html.

The main objective of this program is to reduce the incidence of extended supply interruptions by installing feeder interconnections and additional remote controlled and manually operated switchgear. The intended effect is speed up fault location and also to reduce the size of feeder switching sections so that fewer customers will be directly affected by an interruption lasting more than 12 hours because left off overnight before repair work commences. This is consistent with the intent of the Section 12 of the Supply Code.

With some reservation, we support this provision being included in the capex forecast because it should have some impact on the number of extended supply interruptions. We also consider that it may improve Western Power's performance against the SAIDI and SAIFI service level benchmarks in the access arrangement. We also note that there is no other provision in Western Power's capex forecast for projects targeted at improving the reliability of the distribution network.

Nevertheless we consider it an indirect, and likely expensive, way of achieving the program objective because it does not directly address the root cause of the problem. Western Power's own web site states that it operates a 24 hour repair service during emergencies, with staff working 16 hour shifts. It is not clear why a similar level of service cannot be provided when necessary if no emergency situation exists. We consider that some of the proposed funding would be more effectively used to provide incentives for staff to take a more flexible approach to the repair of faults in order to allow supply to be restored more quickly to all consumers affected by an interruption occurring at an inconvenient time.

B2 CBD SUBSTATION CAPEX

B2.1 BACKGROUND AND DESCRIPTION

During AA3 Western Power is proposing to construct a new 264 MVA substation within the Perth CBD and also install a new 80 MVA transformer at the existing Cook St substation.

The major cost items are shown in Table B2.1

Table B2.1: Forecast AA3 Capex for CBD Substations ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Zone substation	-	3.9	26.8	59.9	4.8	95.4
Zone substation supply cable	-	-	5.1	22.2	2.4	29.6
Cook St transformer	2.3	10.1	1.1	-	-	13.5
Total	**2.3**	**14.0**	**33.0**	**82.0**	**7.2**	**138.5**

The proposed CBD substation itself will contain 4 x 66MVA transformers, all of which are proposed to be installed during AA3.

Western Power has also indicated that both Forrest Avenue and Wellington St 66 kV substations are approaching end-of-life and considerable asset refurbishment will be required in the next 10 to 15 years to improve their condition and ensure ongoing reliability of supply. In addition, switchgear replacements at Milligan St and Hay St substations are also likely within a 10 to 15 years horizon (Milligan T1 and T3 11kV switchgear will exceed nominal operational life of 45 years in 2018).

As a consequence of the assets requiring refurbishment and/or replacement, Western Power is proposing to decommission the Forrest Avenue substation (nominal capacity of 80 MVA). It argues that the proposed new CBD substation is also required to provide sufficient spare capacity to allow for extended outages at other substations for equipment replacement, while still allowing Western Power to comply with the N-2 security requirement for the CBD, as specified in clause 2.5.3 of the Technical Rules.

Western Power has also indicated that much of the 11 kV distribution network within the CBD is very heavily loaded and, because of this constraint, it is uneconomic to allow for further significant load transfers between substations in the event of supply outage contingencies.

The specific solution that Western Power proposes to address these emerging demand growth and asset condition issues within the CBD incorporates the following key elements:

- Transfer load from Forrest Ave substation to Hay St substation by summer 2013-14;
- Install a third transformer at Cook St substation by summer 2014-15;
- Upgrade metering equipment at Milligan St substation by summer 2015-16;
- establish a new CBD substation and perform associated connection works by summer 2016-17 and transfer load from Hay St to the new substation; and
- transfer load from Wellington St substation to the new CBD substation progressively over a number of years starting before summer 2016-17.

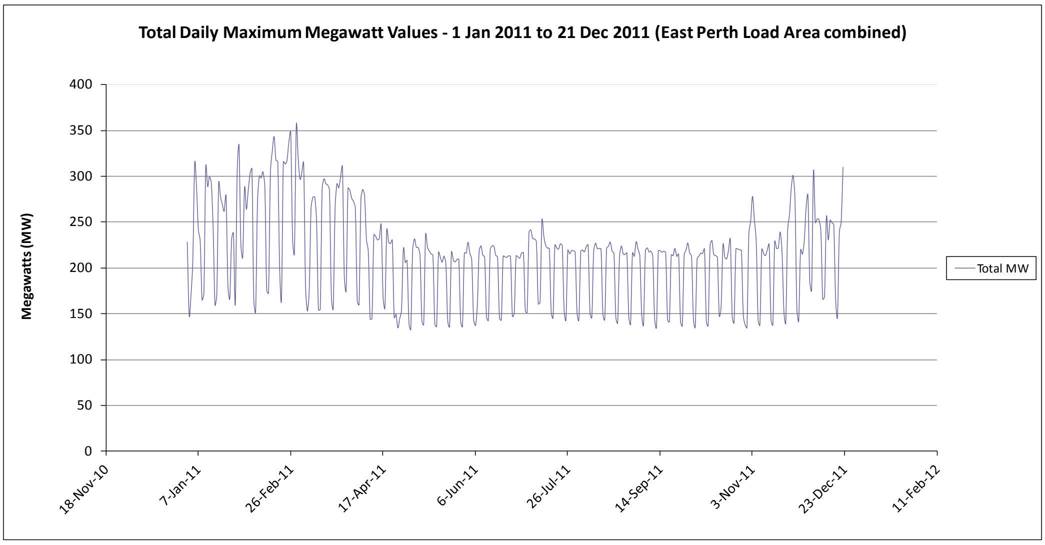
Alternative options were considered in the supporting analysis that Western Power provided for the CBD substation project, but these were not costed. No demand management or other potential project deferral options were considered in the business case.

We note that Western Power's 2010 APR forecasts a peak demand increase of 59 MW between 2012 and 2018 in the Metro CBD load area. In the 2011 APR this forecast increase is reduced to 48 MW. In addition the forecast 2018 peak demand reduces from 455 MW to 431 MW between the two forecasts.

B2.2 DISCUSSION

Ignoring the potential decommissioning of Forrest Avenue substation, Western Power's AA3 capex forecast involves installing 344 MVA of new transformer capacity (including the new substation and the additional Cook St transformer) in an area where the peak demand growth was project to increase by only 59 MW[79]. Furthermore, the 2011 actual peak demand in the CBD/East Perth area was in the order of 350 MW, as evidenced by Figure B2.1, which shows the daily maximum demand figures in the East Perth /CBD load during 2011. The figure also indicates a seven month window between April and November, when the CBD peak demand was no higher than 250 MW. We accept that issues other than actual and forecast peak demand, such as transfer constraints and the requirement to still meet the security criteria in the Technical Rules for the duration of any asset replacement project need to be considered when preparing a CBD network development plan. However the fact that actual loads are much lower than assumed by Western Power, and the existence of a seven month window where network peak demand reduces by approximately 100 MW, at the very least raises a need for a detailed development plan to support the argument that the capex forecast by Western Power is consistent with a least cost development program. This is notwithstanding the fact that, given that the new substation is not required until 2016-17, detailed planning and business case preparation for the project has still to commence.

Figure B2.1: 2011 Daily Maximum Peak Demands. East Perth Load Area



Source: Western Power

Western Power has provided no condition information indicating an urgent need to replace existing CBD assets (other than for the Milligan St switchgear). Indeed, the information provided indicates a near term horizon of about 10 years, which indicates that the asset replacements will not be needed until the end of AA4. While it notes that Milligan St switchgear will reach the end of its expected operational life in 2018, this is not in itself sufficient to justify a $135 million investment in a new CBD substation and related works in the AA3 period.

As noted above the daily maximum demand chart also highlights that there is a seven month period from April through to the end of October when the peak maximum demand

79 Based on the 2010 APR, which was the demand forecast used by Western Power to predict is AA3 capex requirement.

does not exceed 250 MW. This window provides an opportunity for Western Power to schedule refurbishment and replacement works without invoking any constraints that would violate the security requirements of the Technical Rules. We accept that projects such as switchboard replacements are complex and that Western Power may consider that a seven month window is too short. However options, such as two shifting, are available to accelerate project implementation times and we have seen no evidence that Western Power has considered the potential or cost effectiveness of using such approaches to allow the new CBD substation to be deferred or reduced in scope. There appears to have been no consideration of demand management, power factor correction or the possibility of minor strategic network upgrades as potential alternatives that might allow the substantial investment in a new substation to be deferred.

Western Power has identified emerging issues in respect of supply to the CBD but has made no firm decisions as to how these might be addressed. It has not decided whether the Forrest Avenue and Wellington St substations should be decommissioned, refurbished or rebuilt, although it favours decommissioning Forrest Avenue. Its capex forecast provides for a double circuit cable to the new substation from the East Perth terminal station even though it owns a suitable site for a new substation in James Street that can be supplied by an existing overhead line. It notes that, as part of the CBD project development phase, Western Power will explore the expansion and refurbishment of Wellington St *to defer more costly investment*.

The analysis appears to consider limited distribution voltage transfer capacity as a constraint that drives additional transmission system investment. There is no consideration as to whether it would be more cost effective to install larger distribution cables or more distribution feeders to increase the distribution voltage transfer capacity between substations. This could provide for new load and at the same time allow the existing supply transformer capacity to be more effectively utilised, particularly during N-2 contingency situations.

B2.3 CONCLUSION

We consider that the proposal to install an additional transformer at Cook Street substation is reasonable and suggest that the cost of this project be included in Western Power's approved AA3 capex requirement.

Western Power has identified a number of emerging issues within the CBD that in time will need to be addressed. However it does not have a properly developed strategic plan to deal with them. It has indicated that is in the process of developing a strategic development plan for the CBD area covering a 25 year horizon which is due for completion in the first quarter of 2012. We do not understand why the completion of this plan was not advanced so that the outcome could have taken into account in preparing the AA3 capex forecast.

In the absence of such a plan, it is difficult not to conclude that the new CBD substation proposal is a solution that has been developed, with little consideration of cost, primarily to ensure that all potential development scenarios are adequately provided for. There is no evidence that the proposal is consistent with a least cost plan to ensure adequate security of supply to the CBD and even the information provided by Western Power suggests that it is possible that lower cost development options are likely to be available. Furthermore Western Power has not demonstrated that the proposed new substation is required to be commissioned before the end of AA3, and, based on the information provided for this review, we think any new substation could be deferred at least until AA4. This will allow sufficient time for a draft strategic development plan for the CBD to be considered and challenged by Western Power's management, modified as necessary (and possibly even subjected to a public consultation) before being finally approved by the Western Power Board.

We think any strategic development plan should be broadly based and consider all potential risks and responses. One issue we think needs to be considered is whether the dependence on a single terminal station (East Perth) to provide the bulk of the bulk of the supply to the CBD is an acceptable risk or whether Western Power should mitigate this risk by increasing the proportion of the CBD power requirement that is sourced from other terminal stations. We also believe that the strategic plan should integrate transmission and distribution planning and consider whether it would be cost effective to increase the ability to transfer load at distribution voltage between substations to cater for contingency situations. This is a legitimate transmission development strategy even though it does not involve the construction of transmission assets. In addition, the plan should explicitly consider the potential for deferring investment by scheduling asset replacement for times of low network load and even whether it might be cost effective to accelerate some asset replacements if this would avoid the need to construct new assets to cover the replacement period. Given the number of variables, there are likely to be a range of alternative development strategies available to Western Power and a period of extensive condition assessment, brainstorming and analysis may be necessary before an optimal strategy emerges.

It may well be the case that a least cost development plan requires some expenditure over and above the cost of an additional Cook St transformer and may need to be incurred during AA3. However we doubt that it will be anywhere near the $135m cost of the new substation and related 132 kV cabling works proposed by Western Power. The regulatory test and NFIT pre-approval processes will ensure that Western Power is fully reimbursed for such expenditure provided its efficiency can be demonstrated.

In summary we consider that capex for the installation of an additional transformer at Cook Street substation should be included in the approved AA3 capex forecast. However, we suggest the CBD substation works not be included in the approved forecast without substantiation on the need for, and timing of, the project.

B3: PINJARA 330KV TERMINAL STATION

B3.1 BACKGROUND AND DESCRIPTION

In its AA3 capex forecast, Western Power has provided for the construction of a new 330 kV terminal station at Pinjara for a forecast cost of $44.6 million (real 2011-12 excluding real cost escalation), as shown in Table B3.1.

Table B3.1: Forecast Capex for Pinjara Terminal Station

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Pinjara terminal station	-	-	7.6	33.3	3.6	44.6

Source: Western Power

The project is driven by a need to address a forecast N-1 contingency constraint in the Mandurah area that would breach the transmission planning requirements of the Technical Rules. It involves the following works:

- Construction of a new 330kV terminal station at Pinjarra on a site that Western Power currently owns. The terminal will have a breaker and a half switchyard initially configured as a 3-switch mesh arrangement and a single 330/132 kV 250 MVA transformer. Pinjarra terminal station is located close to the 330 kV line between the Shotts and Southern terminal stations. This line will be diverted to supply the new station,
- Diversion of the existing 132 kV Mandurah –Pinjara 81 line into the new terminal station.

Other planned work on the 132 kV network, including the south metro reconfiguration and temporary protection and runback schemes are associated with this project.

B3.2 DISCUSSION

The project is required to address thermal constraint issues arising from line rating limitations because of the meshed nature of the network in the Rockingham and Mandurah/Meadow Springs areas. This mesh arrangement increases the load on the 132 kV lines supplying Mandurah and Meadow Springs, as these lines operate in parallel with the 330 kV system. The limited capacity of these 132 kV lines impacts operational controllability from a generation dispatch perspective. The project, together with its associated works, will allow the 132 kV network to operate in a radial configuration. Generator dispatch will only affect power flows in the 330 kV system, where there is spare capacity, and will no longer affect flows in the 132 kV network.

Western Power considered five alternative approaches to alleviating the current constraint situation and further pending constraints as set out in Table B3.2 below.

Table B3.2 Alternative Project Options ($ million)

Option	Project	Total Capex
1	Establish Hopeland terminal station. Cut into Mandurah-Meadow Springs-Waikiki 132 kV line.	83.72
2.	Establish Hopeland terminal station. Cut into Mandurah-Cataby 132 kV line.	76.48
3.	Establish Pinjara terminal station	36.98
4.	Uprate / reconductor 132 kV circuits	81.68
5.	Non network alternative	Not available

Source Western Power
Note: Costs not updated to real 2011-12 but are consistent for project comparisons.

The Pinjarra terminal station is substantially less costly than the other options evaluated as it is closer to existing 132 kV lines, thus reducing the length of connection to the network.

Further 132kV line works will be required in the area (beyond 2020) to further reduce the network meshing following the establishment of the Pinjarra Terminal. As this work also applies to other options (1, 2 and 4), it is neutral in terms of option ranking so was not included in the analysis.

Western Power has indicated the non-network alternatives are considered unviable at this stage as

- No demand side options to address the issues have been identified; and
- Due to the range and number of unique overloads and contingencies, managing the overloads through a non-network solution would be difficult and would require a number of participating service providers at various locations on the network. This requirement reduces the potential for utilising a network control services solution.

However Western Power has indicated that it consider non-network solutions as alternatives during the detailed project development and business case preparation phase.

B3.3 CONCLUSION

The Pinjarra 330kV terminal project appears to be needed and we consider it strategic in nature because of its impact on network architecture. The proposed project is the lowest cost option of those evaluated and we therefore consider it reasonable to include this project as part of the approved AA3 capex requirement. We note that it is one of a suite of projects planned to change the network architecture so that generator dispatch conditions have less impact on 132 kV power transfers.

Western Power has left the option of non-network solutions available for further investigation. However, given the nature of the network in the area and the high level issue that Western Power is trying to address, we doubt that a non-network solution would be a viable project alternative.

B4 TRANSMISSION SCADA AND COMMUNICATIONS PROJECTS

B4.1 BACKGROUND AND DESCRIPTION

Western Power is proposing to spend $75.3 million capex during AA3 on transmission based SCADA and communications projects. The proposed expenditure is broken down into four main categories as set out in the Table B4.1 below.

Table B4.1: Forecast AA3 Capex on Transmission SCADA and Communications ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Asset replacement	5.9	10.2	11.1	13.7	14.9	55.8
Improvement in service	3.6	0.1	0.3	0.8	0.4	5.1
Core infrastructure growth	2.3	0.9	1.1	2.2	2.5	9.1
Performance and regulatory	2.3	0.5	0.4	0.4	0.3	3.9
Third party actions	0.1	0.1	-	1.2	-	1.4
Total	**14.2**	**11.9**	**12.9**	**18.3**	**18.0**	**75.3**

Source: Western Power

We have examined the asset replacement element of the above proposed expenditure which represents $58.5 million (including real cost escalation) or almost 75% of the total forecast. This line item of the can be further broken down, as shown in Table B4.2 below.

Table B4.2: Forecast AA3 Capex on Transmission SCADA and Communications Asset Replacement ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Master station XA/21	2.8	3.2	2.8	3.1	3.5	15.5
Microwave bearers	-	1.7	2.8	4.8	3.2	12.5
Pilot cable	1.2	1.4	1.3	1.3	1.3	6.4
Other minor projects	2.0	4.2	4.7	5.3	7.9	24.2
Total	**6.0**	**10.5**	**11.6**	**14.5**	**16.0**	**58.5**

Source: Western Power
Note: Includes real cost escalation

B4.2 DISCUSSION

B4.2.1 Master Station XA/21

As indicated in Table B4.2, Western Power is proposing to spend $15.5 million to continue a program of replacement of critical elements of the transmission master station works that commenced in AA2. The master station, also known as the XA/21 energy management system (EMS), is the business critical system that provides the ring-fenced system management real-time visibility and control of the power system, including generator operation and dispatch, and outage and fault management. It also provides data to support the Wholesale Electricity Market (WEM) Rules. Upgrade work completed on this system during AA2 is discussed further in Appendix A12.

The existing XA/21 hardware was purchased in 2005 and has been operated continuously for more than five years. This has exceeded the current industry standard five year life of computer system hardware. Like for like replacements for this hardware are becoming difficult to source as they are no longer vendor supported.

We understand that the XA/21 energy management system is used primarily for controlling operation of the power system under the WEM rules. In Section 7.6 we raised the issue of whether this and other power system operations equipment should be funded from transmission revenue or by the IMO and noted that the boundary between Western

Power and IMO assets had not been defined. We understand that this system has historically been considered a transmission asset and our assessment is predicated on the assumption that this situation will continue.

B4.2.2 Microwave bearers

During AA3 Western Power proposes to invest $12.5 million to replace the Muja to Merredin microwave bearer and commence the Goldfield Alcatel microwave replacement. These radio systems extend the communications backhaul network through areas where the use of optical fibre or other cables is uneconomical.

In order to reduce the risk of lengthy failures of the existing microwave systems, a rolling program of asset replacement is proposed to remove plesiochronous digital hierarchy (PDH) links with new, well supported, higher bandwidth and more flexible synchronous digital hierarchy (SDH) microwave bearer links. Continued asset replacement of islanded and no longer manufactured microwave radio links with PDH - SDH compatible systems will facilitate migration from PDH to SDH.

B4.2.3 Pilot Cable

In AA3 Western Power proposes to invest $6.6 million to replace pilot cables with optical fibre cable or upgrade connections to a digital communication system to maintain reliability of the communications network and its data circuits.

The estimated life of pilot cables varies between 20 and 30 years. Of the 900 km of pilot cable installed on the Western Power network, 90% is over 25 years old. Pilot cables suffer from exposure to damage by the public (70% are overhead cables), channel instability caused by water ingress, external interference and other factors.

In AA3 thirteen sites will have their existing pilot wire protection schemes upgraded to digital protection systems, utilising existing available digital communication systems. The circuits that will be transferred away from pilot cables and on to the digital communication network are mainly located in the Perth metropolitan area and include circuits linking directly to Western Power's central control centre. In addition, approximately fifteen of the most defective pilot cables will be replaced with optical fibre cable.

This replacement program is proposed to extend into AA4.

B4.2.4 Minor Projects

Western power is planning additional capex of $24.2 million to replace other SCADA and communications equipment. This includes:

- Communications infrastructure such as network management system (NMS) equipment, PDH and teleprotection system (TPS) equipment ($17 million); and
- SCADA assets including remote terminal units (RTU), human machine interfaces (HMI) and the global positioning system (GPS) clock ($6.7 million).

B4.3 CONCLUSION

Given the information provided by Western Power we consider that there is a need for the required work to be undertaken. We would not normally propose the replacement of assets solely on the basis of its age profile but we note:

- It is difficult to monitor the condition of SCADA and communications hardware other than by tracking failure rates. Over time, spare parts can also become difficult to source due to technological obsolescence. Hence the replacement of master stations, communication infrastructure and RTUs appears reasonable.

- Western Power has provided evidence of an increasing number of failures of pilot cables and, provided the replacement is prioritised based on formal condition assessments, we consider the replacement of pilot cables to be reasonable.

B5 FIELD SURVEY DATA CAPTURE PROJECT

B5.1 BACKGROUND AND DESCRIPTION

Western Power is planning to spend a total of $34.3 million opex during AA3 on a field survey data capture project as shown in Table 5.1 below.

Table B5.1: Forecast Field Survey Data Capture Project Opex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Field survey data capture project	5.6	7.2	7.2	7.1	7.2	34.3

Source: Western Power

The project involves a full survey of Western Power's transmission and distribution line assets and is aimed at addressing data quality issues that have been highlighted in internal and external audits, regulatory reports, recommendations and orders. It is proposed that the survey will be undertaken using specialist external contractors.

The project is an extension of a pilot project undertaken during AA2 to survey data on a subset of 66,000 poles, approximately 10% of Western Power's wood pole population, in the North Country and South Country regions.

B5.2 PROJECT OBJECTIVES AND BENEFITS

The information provided by Western Power stated that the objectives of the project were to:

1. Improve data completeness:

   Western Power considers that the benefits of data completeness would be to:

   - Improve network modelling capability and increase reliability and power quality for Western Power customers;
   - Reduce public safety incidences;
   - Increase confidence in data quality leading to improvement in the efficiency and effectiveness of investment decisions;
   - Increase the accuracy of Western Power's wood pole serviceability assessment model;
   - Reduce the number of incorrect pole replacements; and
   - Reduce the cost and risk of asset failure.

   In our view, these benefits appear to be overstated. We note that, except for the first bullet above, the claimed benefits will, in general, only be captured if information related to asset *condition* is accurately recorded in the asset database. However the field survey data capture project is concerned only with ensuring that the *existence* and *type* of asset is accurately recorded.

   However, the pilot project business case, which was not initially provided by Western Power in response to our request for information on the project, included significant information as to why data inaccuracies exist. It states that Western Power's existing asset records were created by digitising paper records and that no field checks were undertaken at that time. It also comments that the existence and location of poles was inferred by approximating intermediate pole positions based upon the distance between line deviations and standard bay lengths. A data management team, which is necessary if the quality of asset data is to be assured over time, was not set up until 2003. Even now, the only existing process to improve the quality of legacy data is a desktop cleansing regime, which is limited to populating, or correcting, data by cross checking valid lists of data. Field checks to resolve data inconsistencies are not undertaken.

The business case also notes that no data is recorded on the existence of stays and that data on the number of conductors supported by a pole may be inaccurate. An earlier audit has indicated that the location of approximately 23% of poles may be spatially inaccurate by more than 5 metres. Western Power's pole serviceability model, which is a key component of its wood pole management program uses the number of supported conductors and supported span (or bay in Western Power terminology) length as key inputs.

The business case also notes that the quality of asset data within the Perth metropolitan area is much higher than in rural areas and that in this area a targeted program of asset verification may be all that is needed.

2. Locating missing assets:

   According to Western Power this will:

   - Address EnergySafety's requirement to verify asset records against field installation from the its 2008 distribution wood pole audit review;
   - Ensure that missing assets are included in future pole inspection, maintenance and replacement programs;
   - Enable asset managers to account for the cost of maintaining "new assets";
   - Improve efficiency of wood pole management by reducing time take to locate assets in the field; and
   - Reduce the number of "additional" pole inspections.

   Apart from the third bullet above, these benefits relate specifically to Western Power's rural area wood pole replacement issue. The 2008 wood pole audit noted that there was uncertainty as to the number of wood poles on the distribution network and the recent report Western Power's unassisted wood pole failure rate by the Legislative Council's Standing Committee on Public Administration stated that approximately 0.7% of the distribution poles on Western Power's network had an "unknown location". This situation would seem much less serious than indicated in the business case, which states that 5% of the poles on the three feeders inspected in a 2005 internal audit did not exist in the asset information system.

   However a review of the relevant documentation, including GHD's 2008 Asset Management Audit, suggests that an equally critical issue is the timeliness and accuracy with which Western Power updates its records on the results of pole inspections, replacements and reinforcements.

3. Capturing the sub-metre positional accuracy of assets.

   According to Western Power this will:

   - Support the wood pole inspection program, enabling increased efficiency and accuracy in wood pole serviceability calculations;
   - Increase Western Power's external data sharing capability;
   - Enable Western Power to keep pace with emerging spatial technologies such as GPS and mobile solutions;

- Enhance existing Western Power customer services such as "dial before you dig" and projects such as ISAM and EWDW; and
- Improve accuracy of network connectivity leading to optimised network planning and modelling.

Western Power has stated that the results of is 2005 data audit of three feeders indicated that 23% of poles surveyed were spatially inaccurate by more than 5 metres. However, notwithstanding the supposed benefits listed above, Western Power has not convincingly demonstrated that greater spatial inaccuracy is actually needed. It seems to us that the key requirements for an asset data record are: (i) that the existence of an asset is recorded, (ii) that the type of asset is accurate, (iii) that the condition of the asset is accurately recorded and up to date, and (iv) that the asset can be found in the field. Western Power also argues that accurate pole locations are needed so that accurate span lengths can be input into its wood pole serviceability model. However, we suspect that the error caused by a 5 metre inaccuracy in pole location will be small when compared to the documented uncertainties in Western Power's wood pole management program. We note that the survey will not cover underground cables so the relevance to the "dial before you dig" program is unclear.

B5.3 RELATIVE COST

In its submission, Western Power references similar data capture projects undertaken by six other Australian distribution network utilities. The cost of five of these programs was between \$3 million and \$6 million whereas one program cost \$25 million. Even allowing for the impact of inflation, Western Power appears to be proposing the most extensive data capture project ever undertaken by a distribution network business in Australia.

B5.4 PROJECT ALTERNATIVES

Western Power considered the following alternatives project approaches:

Targeted Approach

This option would target known data quality issues across the entire network and would be limited only to issues that could be quantified. The estimated cost is \$16 million (June 2012)[80]. The option was rejected because it would not correct data quality issues outside the targeted areas and would not resolve the missing asset issue. Western Power also states that the option *would not reduce the corporate risk profile presented by the data quality issue* but provides no support or justification for this assessment.

Reduced Scope

This option would only survey salient points on the network. Only poles that have equipment attached or represent a change in direction would be surveyed and other poles would be ignored.

Western Power states:

> *ETSA Utilities adopted this option in 2005 with success as they do not have wood poles on their network. This option is not suitable for Western Power as our wood poles have a greatly reduced lifespan than the ETSA Utilities' steel and concrete stobie pole. Western Power's intermediate wood poles have the same likelihood of failure as other wood poles on the network.*

We cannot accept this information at face value, given that the field survey data capture project will not capture condition information. However we would need more information

[80] The June 2012 costs quoted in this section are our estimates, based on the nominal costs provided by Western Power. We have developed these estimates by pro-rating Western Power's nominal costs using the ratio of the 2012 cost of Western Power's preferred option and the nominal cost of this option.

on the scope and objective of the ETSA Utilities project before commenting further on Western Power's assessment.

Integrate into Pole Inspection Program

Western Power notes that Powercor attempted a similar approach and it failed. Therefore Powercor had to repeat the data capture work independently of its inspection program. Western Power notes that under this option the time spent at each pole would double for the pole inspector. It considers that this option would also require hardware and system changes as well as extensive retraining of the pole inspectors. It further notes that data capture specialist service providers have significant experience in surveying electrical asset efficiently and accurately. The estimated cost is between $49 million and $61 million. Compared to the cost of the other options, we think this seems high.

We can think of at least one further option that has not been considered by Western Power. Staff and contractors working in the field could be required to report all instances where actual assets did not match the data in the asset records. These reports could be followed up by a specialized data management team and the asset records corrected as required. Over time the accuracy of data records would improve. A proactive approach this nature would require a corporate culture that recognizes the importance of accurate asset information and the need to record changes in asset data in a timely manner. Such a culture would require both internal field staff and contractors to report apparent discrepancies between actual and recorded data and would provide the necessary resources to undertake the field verifications needed to report apparent discrepancies. The information that we have reviewed to date suggests that the required culture does not currently exist within Western Power but in our view, irrespective of the approach taken to data capture, the culture would need to be embedded in the company if the data captured by the survey project is to be maintained over time.

The estimated cost of Western Power's preferred option is substantial. We consider Western Power's identification and analysis of potential lower cost alternatives, as presented in the project supporting information to be inadequate to support the commitment of expenditure of this magnitude.

B5.5 DATA RECORDING

The pilot project required the field survey data to be manually input into Western Power's DFIS. This is time consuming.

For this project Western Power has stated:

> *The data collected through the field data capture project will be stored in Western Power's corporate GIS and asset management system. These systems have been developed as part of the Integrated Solution for Asset Management (ISAM) project. This is an AA2 project that continues into the AA3 period. No additional project spend on IT systems has been required to store the data captured in the field survey data capture project.*

We assume that this indicates that the need for manual transcription is avoided with a significant saving in cost and accuracy. This saving appears to be reflected in the estimated project cost. The pilot project allowed for a survey of around 10% of Western Power's poles for an estimated cost of approximately $5 million (real 2012). The estimated cost of surveying a further 70% of poles is $34.3 million. We would have expected that experience from the pilot project would lead to implementation efficiency gains but the extent to which such gains have been incorporated into the forecast is limited.

B5.6 DATA MAINTENANCE

Western Power has advised:

> *Over the course of the project, a data capture framework will be developed to identify data collection activities that occur across the business. It is proposed that these activities will be consolidated into a business-as-usual data capture activity as part of the asset maintenance expenditure. This will result in a modest increase in the asset maintenance opex activities, offset with reductions in other activities. This solution aims to balance the urgent business requirement for data quality improvements with the realisation that in the long-term data quality needs to be maintained. The continuation of field data capture as a business as usual activity will significantly reduce the overall level of maintenance expenditure.*

We are concerned that what is proposed here is merely a "consolidation" of existing data collection activities. Our review of documents related to the pole management program leads us to conclude that the timely collection and entry of asset condition data has been a major problem for Western Power and a significant cause of the inefficiencies that have been identified in the program. We think that the importance of accurate asset data, in respect of both asset existence and asset condition, needs to be more firmly embedded in corporate culture and that field staff should be required to report all discrepancies between the asset records they use and what is actually found in the field. Once such discrepancies are reported, they need to be acted on. The pilot project business case states that, at present, such reports are not acted on where a field check is required. This is not acceptable.

Western Power's current data collection processes do not appear to be working effectively and this is a major contributing factor with the difficulties Western Power is now experiencing with is asset management programs. If this problem is not urgently addressed, then expenditure on the ISAM project and the field survey data capture project could well be wasted.

B5.7 CONCLUSIONS

It is apparent from the pilot project business case that the accuracy of asset data is largely a legacy issue that the current management needs to address. Nevertheless, the situation has deteriorated as a result of a longstanding neglect of the need to keep asset records up to date and the lack of appropriate business procedures to do this.

The actual condition of the asset database is not known. The assumptions used to develop the pilot project are largely based on an internal audit of three feeders undertaken in 2005. The findings of the pilot project will provide a much more accurate picture of the quality of existing asset data and should be analysed before the design of any ongoing field survey data capture project is finalised.

The proposed project appears to be the most comprehensive asset data survey ever undertaken by a distribution network in Australia. The cost of the project is substantially higher than similar projects undertaken by many other network businesses and it is not clear that the project in its present form is needed or that it will produce benefits that outweigh the costs. We think that serious consideration should be given to a program that targets areas where data quality is known to be poor and uses a program of field checks to resolve identified data discrepancies in areas, such as the Perth metropolitan area, where data quality is known to be relatively good.

We further think that Western Power should demonstrate that this project is effectively integrated with initiatives to improve the quality and timeliness of its asset data maintenance. We also note that it is common industry practice to assign a unique asset identifier (generally a number) to each pole and to tag the actual pole with this asset identifier. It is not clear whether Western Power is proposing to do this as it is not discussed in any information provided to us. However, we think this should be considered.

B6 SMART METER ASSET REPLACEMENT

B6.1 BACKGROUND AND DESCRIPTION

Western Power has proposed capex of $101.2 million during AA3 to meet its obligation to replace 280,000 three phase meters that are noncompliant with Section 6.8(d) of the Metering Code. It has previously sought and received exemptions for replacing this metering population but is mandated to complete the replacement by December 2015. Western Power proposes to take the opportunity to replace these meters with market compliant smart meters. Only the cost of a standard interval meter is included in the metering expenditure which is set out in the Table B6.1 below.

Table B6.1: Forecast Capex for Three Phase Meter Replacement ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Smart meter asset replacement	1.5	33.9	33.2	28.8	3.7	101.2

Source: Western Power

Western Power has advised that the cost of a three phase smart meter is the same as a standard meter. Therefore, as the meter replacements are required for other reasons, in developing the smart grid program, the metering cost has been allocated to meter replacement rather than to any smart grid cost allocation[81]. However the cost of the communication units required to provide smart grid functionality is not included in this forecast.

Western Power has indicated that the capex forecast for this program is based on current prices (including some reductions anticipated by vendors) with a 10% scale discount. For the proposed large scale roll out of meters, installation is assumed to be $55 per meter based on its standard metering contract and experience during the smart grid foundation program.

B6.2 DISCUSSION

Western Power's proposed replacement of 280,000 three phase meters for a total cost of $106.2 million represents an average installed replacement cost of approximately $380 per meter.

For comparison, the NERA report to the Ministerial Council of Energy on the costs and benefits of smart metering in remote areas[82] estimated the purchase cost of three phase meters and communications units as ranging from $368 (direct connected meters) to $463 per meter (CT connected 3 phase meters). This was based on actual costs and costs benchmarked from the Victorian AMI rollout experience. If we deduct the cost of the communications units, for which Western Power has allocated a cost of $90 per meter[83], then we have a benchmark purchase cost of between $278 and $373 per meter.

B6.3 CONCLUSION

Given the benchmark costs quoted by NERA and the scale of the rollout proposed by Western Power, it would appear the purchase costs for meters that are assumed by Western Power may be conservative (or the Western Power assumed incremental costs for communications enabling may be high).

We do not have access to Western Power's purchase costs and appreciate that Western Power has probably not proceeded to tender for the required meter quantities but would anticipate the actual costs could be lower than allowed by as much as 10% to 15%.

81 Western Power has indicated a cost of $320 per meter for both standard and smart three phase meters.

82 NERA Economic Consulting, Costs and Benefits of Smart Metering in Off-Grid and Remote Areas - A Final Report for the Ministerial Council on Energy's Smart Meter Working Group, August 2010.

83 Source – Western Power Response to our question MC25

B7: SMART GRID – OPERATING EXPENDITURE

B7.1 BACKGROUND AND DESCRIPTION

Western Power has proposed to spend $24.3 million on smart grid opex during AA3 as shown in Table B7.1.

Table B7.1: Forecast AA3 Smart Grid Opex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Smart metering infrastructure	-	3.0	3.6	3.3	3.2	13.1
Smart grid pilot programs	-	0.1	0.2	1.9	3.1	5.3
Preliminary planning	3.9	-	-	-	-	3.9
Customer engagement	0.4	0.4	0.4	0.4	0.4	1.9
Total	**4.3**	**3.5**	**4.2**	**5.5**	**6.7**	**24.3**

Source: Western Power

The key elements of the proposed expenditure program are as follows:

Smart Metering Infrastructure

This proposed opex would be used to operate and support the smart grid control and monitoring systems. This involves operations, support and maintenance of smart metering systems and home area networks (HAN), smart meter program development and software licensing costs.

Smart Grid Pilot Programs

This proposed opex would be used to develop pilot programs to investigate non-network alternatives to reducing peak demand and to more effectively utilise smart grid functionality. The programs are designed to cover the establishment of network peak demand reduction incentive schemes, direct load control programs and support for the deployment of in-home displays to targeted customers for peak demand management.

Smart Grid Preliminary Planning

This proposed opex would be used to define the scope of new products and services to be enabled by smart meters, including defining the technical and performance requirements. Included in these costs is further analysis of data from trials and pilot programs, preparation of specifications, preparation of architecture and security designs and tendering for metering and communications infrastructure.

Smart Grid Engagement

This proposed opex would be for community engagement and education to maximise take-up of smart meter services and reduce peak demand. The customer engagement and energy management education will support the deployment of in-home displays and an energy portal to maximise the effectiveness of smart metering programs.

B7.2 DISCUSSION

It is difficult to benchmark the proposed expenditure by Western Power other than to make a comparison with the Victorian advanced metering infrastructure program, which has been quite contentious as a result of the price increases associated with AMI metering[84] and the review of the AMI project by the Victorian Auditor-General[85].

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84 *Final Determination Victorian Advanced Metering Infrastructure Review 2012–15 budget and charges applications*: AER, October 2011

85 *Towards a 'smart* grid' *—the roll-out of Advanced Metering Infrastructure,* Victoria Auditor-General, November 2009

Western Power has acknowledged that the rollout of smart metering will result in a net increase in distribution opex. In its 20 year net present value (NPV) benefit-cost analysis of the smart grid program, Western Power has forecast an NPV increase of $133 million in distribution opex as a result of the program despite field service savings (reduced meter reading, disconnection/reconnection and tariff change costs) of $64 million over the life of the program. These opex savings are more than offset by the additional operational costs of new IT and communications systems and the incentive and operating costs for direct load control programs. The benefits of the overall program are largely driven by customer benefits (rather than direct distribution opex benefits) which Western Power forecast to be significant. This outcome is consistent with other smart metering programs cost benefit justifications.

A ballpark comparison of Western Power's proposed opex compared with the forecast opex of two of the Victorian distribution companies can be seen in Table B7.2 (noting all values are rounded approximations).

Table B7.2: Comparison of Western Power Opex with Victorian Distributors

	Meter Numbers	Annual Opex at end of 2015 ($ million)	Opex per Meter (approx)
Jemena[1]	350,000	15	$42.86
SPI AusNet[2]	700,000	24	$34.29
Western Power[3]	330,000	7.5	$22.73

Note 1: Source - Advanced Metering Infrastructure Roll-out - Subsequent Budget Application from Jemena Electricity Networks (Vic) Limited, 28 February 2011

Note 2: Source - SPI Electricity Pty Ltd Advanced Metering Infrastructure AMI Subsequent Budget & Charges Application - Public Version, 3 March 2011

Note 3: Forecast AA3 opex for smart metering for 2016/17 after rollout of just over 330,000 meters

Western Power's forecast opex compares very favourably with the Victorian costs. Western Power's has taken advantage of the opportunity to leverage the smart metering installation on the back of a requirement to replace all three phase meters, which form approximately 30% of its meter population and serve the larger energy users. In addition Western Power is able to benefit from the ability to target communications in select areas which provide maximum value in terms of value for coverage so that high cost remote communications areas are not included. In the Victorian situation the distribution businesses are required to rollout out smart metering to the entire customer base including high cost communications areas.

Furthermore, Western Power has learned from some of the outcomes of the Victorian experience and a significant part of its forecast AA3 opex is allocated to customer engagement activities. The Victorian Auditor-General's report concluded that one of the key failings in the Victorian programs was a lack of engagement with the community.

B7.3 CONCLUSION

We see no basis to conclude that the proposed AA3 opex for Western Power's smart metering installations is unreasonable if the smart grid program proceeds. We also acknowledge the unique opportunity that Western Power has to leverage off the mandatory replacement of the three phase meters, which generally serve the higher use consumers in Western Power's consumer base.

From a benchmarking perspective, the forecast opex is low compared to the Victorian jurisdiction. This in itself does not mean the expenditure proposed by Western Power is necessarily efficient given that the Victorian rollout was more extensive and was mandated at an earlier time using potentially inferior technologies.

We suggest that the benefits arising from the program in AA3 be closely monitored, and also that there be independent participation in this monitoring effort. In particular, we consider that the full rollout of smart grid technologies to all consumers, as presently contemplated by Western Power after AA3, should not be considered a fait accompli and should be dependent on the success of this more limited three phase rollout. Further, in approving the overall smart metering program (both from a capex and opex perspective) we suggest that considerable emphasis be placed on establishing appropriate mechanisms to ensure that the customer benefits that underpin the overall economics of the project are realised.

B8 SMART GRID – CAPITAL EXPENDITURE

B8.1 BACKGROUND AND DESCRIPTION

Western Power is proposing to invest $91.4 million capex (including real cost escalation) in AA3 on infrastructure and programs to extend smart the metering capability provided by the business. A breakdown of this forecast is shown in Table B8.1.

Table B8.1: Forecast AA3 Smart Grid Opex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Smart metering infrastructure	1.8	23.4	23.9	14.4	6.9	70.6
Smart grid pilot programs	-	-	2.2	5.2	8.0	15.4
Grid side and demand management trials	0.7	1.2	1.2	1.2	1.1	5.5
Total	**2.6**	**24.6**	**27.4**	**20.9**	**16.0**	**91.4**

Source: Western Power.
Note: Includes real cost escalation.

The main features of each of these expenditure categories are discussed below:

Smart Metering Infrastructure

The smart metering infrastructure consists of the following:

- Enabling communications on the 280,000 non-code-compliant three phase meters and the expected 52,000 new three phase meters that will be installed during AA3 at a cost of [redacted] per meter;
- Back office and last mile communications;
- Control systems for demand management;
- Back Office IT software applications; and
- Customer specific education on smart meter infrastructure, energy efficiency and demand management programs at an estimated cost of $30 per customer.

This investment will cover all major urban areas including Perth, Geraldton, Kalgoorlie, Bunbury and Albany. The required communications backbone infrastructure already exists to all these areas so it is only the "last mile" communication channels that need to be installed.

Smart Grid Pilot Program

This provides $15.4 million for implementation of systems to enable customer demand management including direct load control devices (DREDS) and infrastructure for power factor correction.

Grid Side and Demand Management Trials

A total of $5.5 million has been allocated in for a series of trials that leverage the network connections elements of smart metering technology including:

- dynamic line rating calculations;
- integrated low voltage network management incorporating assessment of appliance and electric vehicle impacts on the network;
- power system network management including fault detection;

- integrating photovoltaic inverters onto the network; and
- edge of grid distributed energy solutions aimed at more cost effectively providing supply solutions at grid extremities.

B8.2 DISCUSSION

There are many conflicting documented case studies on the success or otherwise of smart metering, also called advanced metering infrastructure (AMI). The mandated rollout of smart metering in Victoria, for example, has been contentious and the economic benefits that were modelled have not materialised as anticipated. However, in Western Power's situation there is a unique opportunity to leverage the mandatory replacement of 280,000 non-compliant three phase meters by December 2015. It is worth noting that three-phase consumers are generally the higher energy users and this provides greater opportunity for the benefits of smart grid technology to be realised.

Western Power has commissioned a detailed cost benefit analysis on the rollout of smart metering to include single phase customers following on from the proposed initial AA3 investment and the modelled impacts on its own costs beyond AA3 are shown in the Table B8.2 below.

Table B8.2: Modelled Costs of Smart Grid Program ($ million, real 2011-12)

	Capex	Opex	Total
AA4	(149.8)	(38.7)	(188.5)
AA5 onwards to 20 years	159.4	(64.6)	94.8

Source: Western Power
Note: Negative number represent a net cost while positive numbers are a net benefit.

Table B8.2 shows that over the life of the program there is expected to be a net cost to Western Power. However, the benefit cost study conducted by Western Power indicates that this will be more than offset by a high societal benefit, resulting primarily from energy savings and reduced wholesale costs. Overall, the net benefits of the program over 20 years are estimated to be $208 million.

Figure B8.1, taken from Western Power's cost benefit analysis, shows the large differences in the costs and benefits expected to accrue to different stakeholders.

Figure B8.1: Stakeholder Costs and Benefits from Smart Grid Program

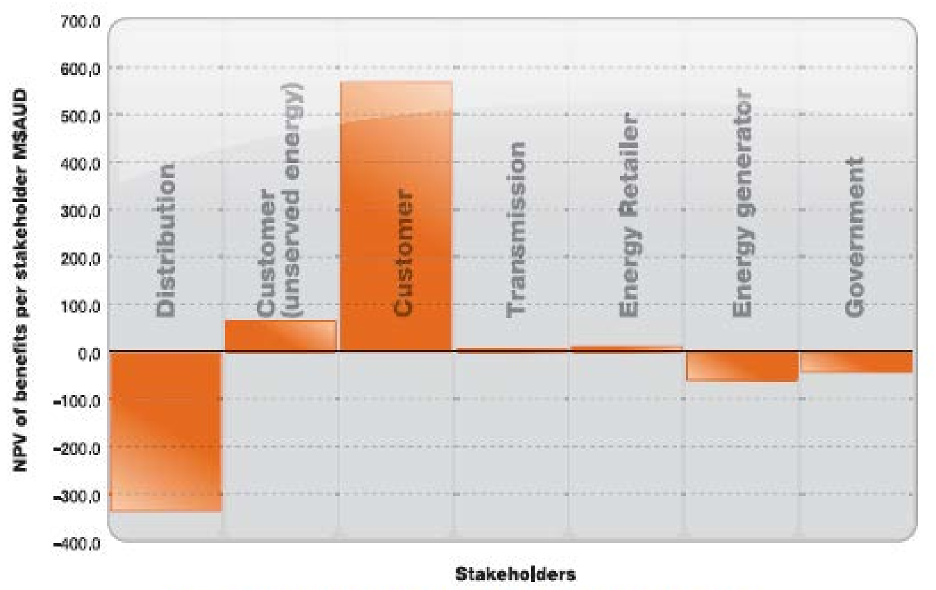

Figure 1-B Initial stakeholder allocation of NPV benefits

B8.3 CONCLUSION

It could be argued that the financial benefits to stakeholders of smart grid implementation have yet to be validated despite various trials and large scale roll outs in Australia. However, given Western Power's unique situation where it has the ability to leverage the mandated replacement of 280,000 three phase meters, we consider that the smart grid deployment proposed by Western Power for AA3 is more likely than most to realise net stakeholder benefits over time.

Western Power has provided a very thorough analysis of potential benefits arising out of its proposed smart grid program and, while various modelling assumptions could be debated, the overall program does appear to offer a potentially promising net benefit to stakeholders. We think Western Power has been rigorous in forecasting the costs of the program and note that it is proposing a relatively strong investment in consumer education to attempt to ensure that the wider stakeholder benefits are actually realised.

As noted in the discussion in Appendix B7 on the opex associated with the program, we would strongly suggest that the benefits arising from the smart metering program during AA3 be monitored and compared with the modelled results. In order to mitigate any risk of bias, we also suggest that there be independent participation in this monitoring effort.

B9 INDOOR (INTERNAL) CIRCUIT BREAKER REPLACEMENTS

B9.1 BACKGROUND AND DESCRIPTION

Western Power is proposing to spend $60.1 million capex in AA3 on indoor circuit breaker (switchboard) replacements as shown in Table B9.1

Table B9.1: Forecast AA3 Capex on Indoor Circuit Breaker Replacements ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Indoor circuit breaker replacements	5.5	15.9	14.4	14.3	10.0	60.1

Source: Western Power.

During AA3 Western Power is planning to replace eight indoor switchboards from five substations as a result of condition based assessment of these assets. All of these switchboards have pitch-filled insulation. One of the replacements proposed is for Milligan Street which is a key component of the CBD supply.

B9.2 DISCUSSION

Western Power has experienced four catastrophic failures of indoor circuit breakers in pitch-filled type switchboards in the last 10 years. Approximately 35% of the indoor circuit breaker population has been assessed as being in "poor" or "bad" condition. Indeed, about 50% of pitch filled switchboards are considered to be in "bad" condition or worse. Western Power has documented 117 major defect issues with pitch filled switchboards since 2000.

The switchboards are key assets and given their condition, Western Power will replace eight of the 26 indoor switchboards assessed to be in "bad" condition during AA3 with the remaining indoor switchboards to be either:

- made redundant through other works enabling them to be decommissioned; or
- targeted for replacement during AA4

Replacement was prioritised based on condition, loading, availability of spares, location and risk within the network. The switchboards that have been scheduled for replacement have been in service for periods ranging from 38 years to 50 years.

B9.3 CONCLUSION

We have reviewed the information in Western Power's network management plan (NMP) and additional information provided by it in response to our additional information requests. Most of these circuit breakers operate at distribution voltage and are located within zone substations. The age profile shown in the NMP shows a significant number of switchboards more than 35 years old. While age in itself is not a good criterion for determining the need for replacement, condition based assessments of the equipment indicates that many are in bad condition, including all of those scheduled for replacement in AA3.

We fully concur with Western Power's proposal for an accelerated replacement program for these indoor switchboards, noting that catastrophic switchboard failures are a potential safety hazard.

B10 MUJA - KOJONUP 132KV REINFORCEMENT PROJECT

B10.1 BACKGROUND AND DESCRIPTION

Western Power has included a provision of $81.5 million for this project in its capex forecast for AA3, as shown in Table B10.1. The project involves replacing an existing 132 kV line between Muja and Kojonup with a new double circuit line.

Table B10.1: Forecast Capex for Muja-Kojonup 132 kV Line ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Muja-Kojonup 132 kV line replacement	-	-	-	14.9	66.6	81.5

Source: Western Power.

In order to avoid network constraints (under N-1 contingencies) this upgrade is required to be in-service by summer 2017-18. However some works are required to be carried out during AA3 with the balance of the project work required early in AA4. The investment is proposed in the absence of a firm proposal to connect the potential Grange Resources Southdown mine (90 km north-east of Albany), as this project is not yet committed and therefore has not been allowed for in the AA3 capex forecast. Should this load eventuate, the proposed augmentation will need to be reconsidered. (The Southdown proposal would require the construction of a double circuit 330 kV transmission line from Muja to Southdown, passing close to the existing Kojonup substation. This would allow the future creation of a 330 kV terminal station to reinforce the network south of Kojonup to Albany).

In the absence of the Southdown mine, the preferred network solution involves the replacement of the existing Muja-Kojonup 81 line with a double circuit, 132 kV steel pole line strung with mango conductor and decommissioning and removal of the old line.

B10.2 DISCUSSION

More details on the basis for undertaking this project were set out in Western Power's application to the ERA for a regulatory test exemption for a 330 kV network augmentation to supply the proposed Southdown mine. In particular, we reviewed a Western Power project planning report[86] that discusses the base options for reinforcement between Muja and Kojonup, with the base options being 132 kV network reinforcements between Muja, Kojonup and Albany. Under the base scenario, these would not be affected by the Southdown mine, which would connect to Muja via a dedicated 330 kV connection asset.

That report identified that a network control service (NCS) solution at Albany was the most appropriate short-term option solution to addressing thermal constraint issues in the region, where the existing Muja-Kojonup 81 circuit is forecast to overload in summer 2013-14 (under N-1) conditions and the existing Muja-Kojonup 82 circuit is forecast to be overloaded and in breach of the Technical Rules in summer 2016-17. Western Power's analysis showed that by 2017-18, a transmission solution to Albany is likely to be more economical than continuing with NCS contracts. This is due to the forecast increase in NCS dispatch time to meet growing demand.

B10.3 CONCLUSION

The proposed investment to reinforce the Muja-Kojonup 132 kV network exceeds the major augmentation threshold and under the Access Code will need to be subjected to a regulatory test before Western Power commits to its construction.

86 Western Power "*Options for integrating a major augmentation proposal for Southdown Mine with reinforcements to the existing transmission network from Muja to Albany*", May 2011

We consider that there is a need for network constraints to be addressed in this load area. The specific solution and solution timing involves a number of uncertainties given that:

- the Southdown mine may proceed

- NCS is assumed to allow deferral of the commissioning date of project to summer 2017-18 but committed NCS prices have not been contracted by Western Power

- the point at which NCS become less economic than the actual project is not clearly known

Given the uncertainties surrounding various aspects of the project it is difficult to determine the exact timing of the project and as such it may be an option to remove the project from the AA3 approval process and let Western Power proceed with a separate approval process once the likelihood and costing of alternative options is more certain.

B11 STRATEGIC PROGRAM OF WORKS (SPOW)

B11.1 BACKGROUND AND DESCRIPTION

Western Power has included a provision of $76.2 million (including real cost escalation) in its AA3 capex forecast to fund a strategic program of work (SPOW) involving the continuation of the modernisation of its enterprise IT systems that commenced in AA1 and continued through AA2.

A disaggregation of these costs (including the impact of cost escalation) is shown in Table B11.1.

Table B11.1: Forecast Enterprise Systems Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Ellipse	3.0	2.0	1.0	1.0	2.0	8.0
ESRI and Telvent products	2.0	1.0	-	-	2.0	5.0
Mincom field enablement suite	2.0	1.0	-	-	2.0	5.0
Primavera project portfolio management systems	2.0	1.0	-	1.0	-	4.0
Document management system	-	-	1.0	-	-	5.0
Business intelligence	2.0	2.0	-	1.0	-	5.0
Metering systems	2.0	10.0	12.0	-	-	24.0
Ariba			1.0	-	-	1.0
Oracle customer care and billing	2.0	1.0	-	1.0	-	4.0
DigSilent Powerfactory	-	0.5	-	0.5	-	1.0
Trouble call system – upgrade impacts	-	-	1.0	-	-	1.0
Forecast expenditure (ESAMP)	**15.0**	**19.5**	**16.0**	**4.5**	**4.0**	**59.0**
Asset management systems	3.0	3.0	3.0	3.0	3.0	15.0
Rescheduling of metering project	7.0	-	(12.0)	-	-	(5.0)
Cost escalation to 2011-12	1.1	1.0	0.3	0.3	0.3	3.1
Cost escalation after 2011-12	0.4	1.1	0.6	0.9	1.1	4.1
Total (AA3 access arrangement information)	**26.5**	**24.6**	**7.9**	**8.8**	**8.4**	**76.2**

Source: Western Power

The major expenditure items continued from AA2 relate to the:

- *Integrated Solution for Asset Management (ISAM):* This system will replace the current geographic information system (GIS) with a commercial package and replace the asset management systems with the asset management modules in Ellipse – Western Power's main enterprise system.

- *Mobile Workforce Solution (MWS):* This system will provide a mobile workforce solution for all planned work undertaken in the field enabling optimised schedule and dispatch and real time capture of asset and works data.

- *Equipment and Works Management Data Warehouse (EWD):* This system will provide a data warehouse for equipment and works management to provide a single source of information for decision making around equipment and work.

- *Network Customer Information System (NetCIS)*: This will be a network billing and customer relationship management solution to eliminate the dependency on Synergy for billing data and enable improvements in processes supporting customer initiated work and customer service activities.

- *Meter Data Management (MDM):* This system will facilitate the management of meter data in accordance with the deregulated market where there is an increased requirement for interval meter data. The system will also accommodate smart meter data

The above systems represent a significant component of the IT capex forecast with most expenditure occurring in the first two years of AA3. The remaining capex in the forecast is primarily for incremental upgrades and improvements to existing systems.

B11.2 DISCUSSION AND CONCLUSION

The capex forecast appears to be consistent with Western Power's enterprise systems asset management plan (ESAMP) and on balance is a considered approach based on continuing and completing major system upgrades and then carrying out incremental improvements and minor upgrades.

A significant amount of the expenditure relates to improvements in asset management systems and the incorporation of a works program governance model. Given historical issues with certain elements of asset management and some governance processes the investment in such systems appears to be warranted and will hopefully:

- assist in the rationalisation of Wester Power's asset management systems;
- improve the timeliness of updating condition assessment and other maintenance activities; and
- enhance the reporting capability in relation to asset management

We are not in a position to comment on the actual estimates used in the development of the forecast costs (and Western Power has indicated that they will need to go to tender to finalise pricing) but believe that the expenditure items should assist the business in meeting its compliance obligations and provide a platform for more efficient business operations and this should flow through to improvements in operating and asset replacement costs for the business if utilised effectively.

Overall we believe the level of expenditure is reasonable and note that it is much higher in the earlier years of AA3 reflecting an investment in major upgrades with other costs representing ongoing incremental improvements.

B12 DISTRIBUTION POLE MANAGEMENT CAPEX

B12.1 BACKGROUND AND DESCRIPTION

Western Power is forecasting capex of $657.7 million for wood pole management during AA3 as shown in Table B12.1. This will fund an intensive pole replacement and reinforcement program.

Table B12.1: Forecast Capex for Distribution Wood Pole Management ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Wood pole management	115.8	123.3	130.9	138.6	149.1	657.7

Source: Western Power.

The proposed program involves average annual capex almost 50% higher in real terms than the corresponding capex during AA2. This reflects the fact that wood pole management is now seen as an area of extreme risk to Western Power. This extreme risk profile is driven by the risk to public safety of unassisted pole failures, the potential for bushfires to be started by pole failures and the high level of scrutiny given by both EnergySafety and the Legislative Council's Standing Committee on Public Administration to the condition of Western Power's distribution wood pole assets and Western Power's management of this issue. Furthermore, Western Power's unassisted wood pole failure rate is significantly higher than that of other Australian distribution network service providers.

Wood poles are the single largest asset type within Western Power's distribution network with a population of 630,000, 70% of which are jarrah, of which approximately 30% are over 40 years old. The majority of Western Power's current pole population was installed between the mid-1960s and the 1990's. A significant proportion of the wood pole population is located in areas where the bush fire risk is classified as high or extreme.

Western Power operates a condition-based pole management regime in line with Australian industry practice. Under this regime, individual pole serviceability is assessed through an inspection-based monitoring system, with inspections on a four-year cycle. Poles that are identified as unserviceable are either replaced or reinforced to ensure the safety and reliability of the network is maintained. Reinforcement is the preferred option, given its relatively low cost, and a large proportion of poles are reinforced at some stage in their lives. Unreinforced wood poles typically have an average usable life expectancy of about 35 years, as reported by the Energy Networks Association (ENA). This can be extended to approximately 50 years using steel reinforcement techniques.

Western Power's unassisted wood pole failure rate is two to four times higher than the Australian average and twenty times higher than that of the best Australian distribution network service providers. This was recognised by Western Power in 2006 and Western Power is targeting a progressive improvement in its unassisted pole failure rate year on year during AA3.

B12.2 DOCUMENTS REVIEWED

The documents that we reviewed for this analysis include those shown in Table B12.2.

Table B12.2: Documents Reviewed on Distribution Wood Pole Management Program

Document	Western Power Reference
Wood Pole Asset Management Plan 2011-17	DM# 8172520
EnergySafety Order (2009:01) (Network Performance)	DM# 6654153
Wood Pole Inspection Procedure	DM# 5449945
Document outlining the wood pole inspection method / criteria that applied in 2006/07(Network Performance)	DM# 3796514
Presentation to EnergySafety on wood pole management approach / options (Network Performance) (14 April 2011)	DM# 8147752
Laboratory results for pole integrity tests	DM# 8751301
Presentation to Department of Treasury and Finance on options for wood pole management (Network Performance)	DM# 8525506
Correspondence to EnergySafety from Western Power	DM# 8338694

Source: GBA

B12.3 DISCUSSION

The objective of the wood pole management capex program is to replace unserviceable wood poles as quickly and as practically as possible, with the target of reducing the unassisted pole failure rate to the Australian industry average. Other objectives are to reduce emergency repair costs resulting from unassisted pole failures and to avoid financial penalties. To meet these objectives, a staged approach to delivering these requirements with pole replacements and reinforcements is planned.

Following EnergySafety audit reports issued in 2007 & 2009 and the subsequent issue of EnergySafety's 2009 Order, Western Power developed a revised wood pole management plan (WPMP) covering the final part of AA2 and all of AA3. The WPMP addresses: the replacement or reinforcement of the highest risk poles as soon as possible, reduction of the public safety risk arising from a failure of a wood pole particularly in rural areas, reduction of Western Power's unassisted wood pole failure rates to levels comparable to those achieved elsewhere in Australia and the continuing refinement and improvement in wood pole inspection and management practices.

Western Power has improved its pole inspection techniques and a more comprehensive inspection regime was introduced in July 2010. It is now using its pole inspection data to index the serviceability of individual poles and to refine its mitigation approaches to better achieve the program objectives. However, the new pole inspection procedures, even after evaluation and amendment to improve quality assurance, have still exhibited a significant potential error[87]. This appears to be due to peculiarities in the properties of jarrah wood.

The calculation of serviceability index takes into consideration the residual strength of the pole, the loading to which the pole is subjected, the fire risk associated with the location, whether it is located at a road crossing and whether the pole supports flammable assets such as transformers. The methodology used has significantly increased the number of poles deemed unserviceable and therefore requiring replacement or reinforcement.

In its WPMP, Western Power evaluated three investment models to achieve the program objectives. It considers that its preferred "optimal investment approach" will comply with the intent of the EnergySafety Order. This approach endeavours to ensure that the actions required by the Order will be implemented at the fastest practically deliverable pace even though the specified schedule will not be met. Western Power believes that its improved inspection procedures and more sophisticated serviceability criteria will be sufficient to mitigate the short term safety risk. It believes that deliverability constraints prevent it from fully complying with the requirements of the EnergySafety Order, and that

[87] The error has been determined by testing poles after inspection to validate the inspection result.

a more considered approach will enable the program objectives to be achieved at a lower long term cost.

From EnergySafety's perspective, the 'optimal investment approach' proposed by Western Power does not fully meet the Safety Order requirements and does not adequately mitigate short term safety risks. It has proposed an alternative approach involving precautionary pole reinforcement, which it considers will meet the requirements of the Order and mitigate deliverability concerns. Western Power has considered this alternative but is unable to agree with EnergySafety on the practicality of its proposed approach in terms of deliverability or cost. It is not within the scope of the review to adjudicate or comment on these differences, which we think arise primarily because of the different strategic priorities of the two parties. We suggest that consultation needs to continue between Western Power and EnergySafety.

Western Power's proposed "optimal investment program" involves expenditure of $2,560 million over 15 years, although only $657.7 million will be required in AA3. During AA3, Western Power's forecast pole management capex will account for approximately 76% of Western Power's distribution asset replacement capex forecast.

Western Power has also evaluated different types of replacement pole and has considered consideration of steel, concrete, non-conductive and timber poles. It has concluded that locally grown pinus radiata treated wood poles, using a fire retardant in fire risk areas, provides the most cost effective, technically suitable option.

B12.4 CONCLUSIONS

Western Power has significantly improved its pole management program and inspection techniques in an endeavour to address safety and efficiency concerns and, in its view, to meet the intent of the Safety Order in a manner that is deliverable and affordable. Nevertheless, EnergySafety believes that the WPMP being implemented by Western Power does not adequately mitigate short term safety risks and it therefore is insisting that its Order be complied with in full. We think this gap reflects the differing strategic objectives of the two parties and consider that consultation should continue between the parties in an effort to find common ground.

Given the potential consequences of wood pole failures, and their high risks to Western Power, we think deliverability should be the main constraint on program expenditure. This implies that efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in program costs. While we do not have sufficient information to form a view on whether the WPMP will adequately mitigate short term safety risks we think it would be difficult to justify a reduction in the rate of pole replacement and reinforcement if Western Power's unassisted pole failure rate is to be reduced and the need for the Safety Order to be mitigated.

The report of the Legislative Council's Standing Committee on Public Administration and the asset management audit undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program. The information we have reviewed indicates that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented are possible, particularly if Western Power successfully addresses issues related to records management. However efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the capex provision. There is therefore no basis for suggesting that the capex requested by Western Power to implement this program during AA3 should be reduced.

B13 DISTRIBUTION CAPACITY EXPANSION

B13.1 BACKGROUND AND DESCRIPTION

Western Power is proposing a distribution capacity expansion program during AA3 with forecast capex totalling $386.7 million in this period, as shown in Table B13.1. This is a projected real increase in 55% in the average annual expenditure during AA2.

Table B13.1: Forecast Distribution Capacity Expansion Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Minor projects	41.2	44.7	50.8	42.4	50.3	229.4
HV fault rating and protection	5.5	6.4	7.8	13.7	14.4	47.9
Overloaded transformers and LV cables	11.0	10.9	10.8	10.7	10.8	54.1
Transmission driven	7.4	10.3	13.3	15.6	8.7	55.2
Total	**65.1**	**72.3**	**82.7**	**82.4**	**84.3**	**386.7**

Source: Western Power

The program is driven by the growth in the peak demand in different parts of the network and the need to work towards increasing compliance with the planning standards in the Technical Rules. The forecast capex requirement is based on the peak demand forecast in the 2010 APR. We accept this for the purposes of this assessment as it was the latest peak demand forecast available when Western Power's AA3 capex forecast was prepared.

B13.2 ANALYSIS

The purpose of this projected capex is to:

- Ensure the thermal capacity of assets are not exceeded by reducing the risk of overloading distribution feeders and to provide adequate capacity for growth;
- Maintain voltage within prescribed limits for safe operation of the network and to maintain a load balance across the asset;
- Ensure the maximum fault level at any point in the network does not exceed prescribed limits; and
- Ensure a single distribution feeder contingent event does not compromise load transfer to an alternative asset and that adequate protection systems are in place to protect assets and allow load transfer when required.

To support the growing demand for electricity, expansion of the capacity of the distribution network is needed through construction of new assets and increasing the capacity of existing assets including distribution feeders and distribution transformers. Capacity expansion projects are also triggered by the construction of new zone substations and the need to reconfigure and upgrade the distribution network to accommodate the new injection point. This capacity expansion is typical for the industry and generally consists of a few large and multiple small projects.

This projected increase of 55% in average annual expenditure over the actual level is AA2 is incorporates a "catch up" element following the deferral of transmission projects in AA2.

B13.3 CONCLUSIONS

Western Power is following a capacity expansion program typical for the industry. A number of transmission capex projects were deferred in early 2010 pending a review of

Western Power's transmission planning strategy. This had an impact on the actual AA2 capex, which was reflected through to the distribution network. The forecast AA3 transmission capex is significantly higher than the actual AA2 expenditure and this will drive additional distribution capex due to the need to interface the transmission and distribution networks. There is also element of catch up with respect to meeting the requirements of the Technical Rules.

On this basis we consider that the expenditure proposed by Western Power is reasonable, subject to the proviso that the forecast has been prepared based on the 2010 APR peak demand forecast. We note that this capex is subject to the investment adjustment mechanism and any capex not incurred will be returned to customers during AA4. On the other hand efficient expenditure incurred in excess of the forecast may be recovered during AA4, subject to successfully passing an ex post NFIT review.

B.14 BUSHFIRE MANAGEMENT

B14.1 BACKGROUND AND DESCRIPTION

Western Power is proposing an intensive bushfire management program during AA3 with a forecast total capex requirement of $211.7 million as shown in Table B14.1. This is predominantly driven by the risk to public safety and property of asset initiated bush fires. The forecast average annual capex is 32% higher than in AA2.

Table B14.1 Forecast AA3 Capex on Bushfire Management ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Bushfire management	39.2	39.9	40.0	44.1	48.5	211.7

Source: Western Power

The predominant causes of asset initiated bushfires (apart from pole failures which are discussed in Appendix B12) are, wires down causing sparking, clashing conductors causing arcing and dropping of hot conductor material, and pole top equipment in poor condition initiating fires.

B14.2 ANALYSIS

During AA3 it is planned to:

- Replace defective conductors over some 1,550 km of line, which the conductor is aged or otherwise assessed as being in poor condition with the potential to fail, causing a wires down incident and possible fire;
- Reduce the long conductor spans of some 8,900 bays through a high voltage long bay span reduction component;
- Reduction of the potential for conductor clashing in low voltage long bays through the installation of 16,000 conductor spreader arrangements; and,
- Replace some 15,700 poor condition and aged pole top hardware assemblies to reduce the risk of pole top fires.

To meet these objectives staggered approach is planned over the AA3 period to arrest the bushfire risk. The proposed expenditure on the different components of the program is shown in Table B14.2.

Table B14.2 Components of Bushfire Management Capex Program ($ million, real 2011-12)

Subprogram	Estimated Cost
Wires Down	118
Rectification of long high voltage bays	58
Low voltage conductor spreaders	2
Replacement of pole top hardware	48
Total	**226**

Source: Western Power – includes real cost escalation

B14.3 CONCLUSIONS

Western Power has improved its bushfire risk assessment after considering the lessons learned from bushfire analysis after the release of the report of the Royal Commission into the Victoria Black Saturday Bushfires in 2009. The proposed increase in capex for the bushfire mitigation program during AA3 increase reflects this increased awareness of how distribution assets can start bushfires and how this risk can best be mitigated.

We consider Western Power's forecast AA3 capex for this program to be prudent.