Geoff Brown & Associates Ltd

TECHNICAL REVIEW OF WESTERN POWER'S COMMENTS ON THE ECONOMIC REGULATION AUTHORITY'S AA3 DRAFT DECISION.

Prepared for

ECONOMIC REGULATION AUTHORITY

Final

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EXECUTIVE SUMMARY

INTRODUCTION

On 29 March 2012, the Economic Regulation Authority (Authority) released its draft decision on Western Power's proposed revisions to its access arrangement for the AA3 regulatory period from 1 July 2012 to 30 June 2017 (Draft Decision). This Draft Decision relied on the findings of a review we undertook for the Authority on technical matters related to Western Power's proposed revisions and in particular its forecast capital expenditure (capex) and operations and maintenance expenditure (opex) (our Technical Report).

Following the public consultation on the Draft Decision, we were engaged by the Authority to further review the matters covered in our Technical Report in the light of the submissions received, and in particular the Amended Access Arrangement Information (Amended AAI) received from Western Power. The scope of this report is limited to reviewing the issues raised in the Amended AAI in relation to our Technical Report and, where we consider it appropriate, proposing modifications to our Technical Report conclusions. We have not attempted to reconcile Western Power's Amended AAI expenditure forecasts with the expenditure allowances proposed in the Draft Decision and have not considered any matters other than those raised in the Amended AAI unless specifically asked to do so by the Authority.

OPEX

Our proposed revised AA3 opex forecast is shown in the table below.

	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	7.57	7.82	7.98	8.14	8.31	39.82
New One-off Opex	8.69	8.69	8.69	-	-	26.06
Zero Based Line Items	140.06	134.76	133.25	141.42	150.07	699.57
Indirect Costs	44.30	41.88	41.03	39.41	44.83	211.44
TOTAL OPEX	**459.59**	**457.07**	**459.91**	**463.08**	**482.56**	**2,322.21**
Technical Report Proposal	445.53	441.02	452.05	455.07	474.40	2,268.07
Adjustment to Technical Report Proposal	14.06	16.06	7.86	8.01	8.16	54.14
	3.2%	3.6%	1.7%	1.8%	1.7%	2.4%
Additional Adjustment for Removal of Network Control Services						
Distribution NCS	2.30	2.31	2.34	2.35	2.41	11.71
Transmission NCS	10.76	4.51	9.44	12.08	17.68	54.47
ADJUSTED TOTAL OPEX	**446.53**	**450.25**	**448.13**	**448.65**	**462.47**	**2,256.03**

The proposed additional expenditure, which does not include the impact of an opex efficiency factor, amounts to an increase of $54.1 million or 2.4% over AA3. The main driver for these changes is an increase in annual pole inspection volumes and an increase in contractor unit rates over and above those provided for in our Technical Report. Additional factors are the impact of a change in accounting policy for the streetlight switch wire program, the operation of a new wood pole testing facility and the cost of a one-off campaign to increase public awareness of the dangers of Western Power assets.

OPEX EFFICIENCIES

The AA3 opex forecast in the above table is predicated on the assumption that there will be no improvement to the efficiency with which Western Power delivers its opex program. However our analysis indicates that a compounding opex efficiency factor of 2% per year, commencing in 2013-14 should be achievable. The Authority could consider a less aggressive approach, where the efficiency factor is applied only to non-corporate opex. This would leave greater headroom for the operation of the gain sharing mechanism, which could provide a strong incentive for Western Power to increase the efficiency of its operations over time.

TRANSMISSION CAPEX

We suggest that the AA3 transmission capex forecast in our Technical Report be adjusted in as shown in the table below. The adjustments primarily relate to the inclusion substation works within the Perth CBD, consistent with the findings of a long term planning study undertaken by external consultants and additional pole management costs resulting from an increased volume of work and the increased contractor unit rates.

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
East Perth to new Bennett Street Substation - two 132kV cable circuits	-	-	0.5	0.7	4.9	6.1
New CBD Substation	0.4	1.0	10.6	10.3	35.5	57.8
Hay Street to Milligan Street 132 kV cable	0.1	0.4	1.5	5.1	0.6	7.8
Complete Joel Terrace 132 kV Conversion	0.7	4.4	9.9	0.9	-	15.8
James Street - Single Transformer	0.1	0.3	0.9	5.9	13.2	20.4
Impact of modified adjustment for reduced load growth	0.9	4	0.4	-	-	5.3
Clean Energy Future	0.4	0.4	0.4	0.5	0.5	2.2
Pole Management	5.3	4.8	3.3	3.2	1.9	18.5
Total Adjustment	**7.9**	**15.3**	**27.4**	**26.6**	**56.7**	**133.8**

DISTRIBUTION CAPEX

We suggest the adjustments shown in the table below to Western Power's AA3 distribution capex forecast proposed in our Technical Report. The changes are driven primarily by a significant acceleration of the wood pole reinforcement program and increased contractor unit rates. We are also satisfied, on the basis of additional information provided by Western Power, that the provision for transmission driven distribution capex in our Technical Report was insufficient.

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Transmission driven	6.6	3.6	3.3	4.9	5.0	23.4
Asset replacement	50.9	58.5	60.0	60.8	59.0	289.3
Regulatory Compliance	14.9	8.8	7.9	10.0	9.5	51.0
SCADA and Communications	0.4	0.6	0.3	-		1.3
Total	**72.8**	**71.5**	**71.5**	**75.7**	**73.5**	**365.0**

CORPORATE CAPEX

We suggest the adjustments shown in the table below to the AA3 corporate capex forecast proposed in our Technical Report. The adjustments relate to new expenditure that we consider is justified.

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Wood pole testing facility	1.2	1.2	-	-		2.4
ENMAC And DNAR IT Enhancements	0.8	1.1	0.5	0.1	0.1	2.6
Total	**2.0**	**2.3**	**0.5**	**0.1**	**0.1**	**5.0**

AA2 CAPEX

We have reviewed the comments in our Technical Report in respect of Western Power's actual capex during AA2 in the light of the additional information provided by Western Power and see no reason to change our view.

1. INTRODUCTION

On 29 March 2012, the Economic Regulation Authority (Authority) released its draft decision on Western Power's proposed revisions to its access arrangement for the AA3 regulatory period from 1 July 2012 to 30 June 2017 (Draft Decision)[1]. This Draft Decision relied on the findings of a review we undertook for the Authority on technical matters related to Western Power's proposed revisions and in particular its forecast capital expenditure (capex) and operations and maintenance expenditure (opex) (our Technical Report)[2].

A period of public consultation followed the release of the Draft Decision and submissions closed on 29 May 2012. Following the consultation period, we were engaged by the Authority to further review the matters covered in our Technical Report in the light of the submissions received, and in particular the Amended Access Arrangement Information (Amended AAI)[3] received from Western Power. This report documents this further review. It also provides advice to the Authority on new issues raised in the Amended AAI that are relevant to the matters considered in our Technical Report.

The scope of this report is limited to reviewing the issues raised in the Amended AAI in relation to our Technical Report and, where we consider it appropriate, proposing modifications to our Technical Report conclusions. We have not attempted to reconcile Western Power's Amended AAI expenditure forecasts with the expenditure allowances proposed in the Draft Decision and have not considered any matters other than those raised in the Amended AAI unless specifically asked to do so by the Authority.

In this report all forecast expenditures are in real 2011-12 dollars and, unless otherwise noted, exclude real cost escalation.

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

2 *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017:* Geoff Brown & Associates Ltd, 27 March 2012.

3 *Amended access arrangement information for the Western Power Network - Response to the Economic Regulation Authority's 29 March 2012 Draft Decision:* Western Power, May 2012.

2. ASSUMPTIONS

2.1 INTRODUCTION

In its Amended AAI Western Power has questioned many of the assumptions that underpinned the analysis in our Technical Report. In this chapter we comment on Western Power's submissions in respect of these assumptions to the extent that they relate in general to the validity of our analysis. Submissions made in respect of specific expenditure line items are discussed in the relevant section in later chapters of this report.

2.2 REVIEW OBJECTIVE

Before considering individual assumptions in detail it is helpful to consider the overarching objective of the expenditure review. We noted in our Technical Report that:

> *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[4].*

We also observed that:

> *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 business, 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[5].*

As implied by these observations, we considered that the overarching objective of the review was to form a view on the level of capex (and opex) that an efficient service provider operating the Western Power network would require to provide the required level of service. We took into account Western Power's current operating position and, on the advice of the Authority, assumed the demand forecast in the 2011 Annual Planning Report (APR)[6]. However, our analysis did not assume the continuation of current business processes and allowed for the capturing of operating efficiencies where we considered these were available to Western Power.

In undertaking the review we considered in some detail the need for the various expenditure line items identified by Western Power and in doing so formed a view on whether this expenditure was efficient and how it should be prioritised. Nevertheless, Western Power operates in a dynamic environment and will need to review and reprioritise its expenditure requirements as the environment changes with the passage of time. Hence the review should not be interpreted as explicitly recommending the approval or disproval of individual expenditure line items.

The conclusions of our review were also mindful of the regulatory framework within which Western Power must operate. As growth related and customer driven capex is subject to

4 Technical Report, Section 7.1, p75.
5 Technical Report, Section 7.1, p75.
6 *Annual Planning Report 2011:* Western Power, Table 4.3, p49.

an investment adjustment mechanism (IAM), prudent growth related and customer driven capex not provided for in the Authority's determination will eventually be recovered. The most serious risk to Western Power if these capex requirements are under-stated in the Authority's Final Decision is difficulty in obtaining finance.

Western Power has a history of over-forecasting its growth related capex requirements. For example, based on its forecast 2011-12 expenditure prepared at the end of the first quarter, during AA2 Western Power is expected to spend only 31% of its allowed AA2 network capacity expansion capex. This implies that, notwithstanding the fact the excess revenues to Western Power will be returned to consumers during AA3, the short term cost of electricity to consumers during AA2 was higher than it needed to be. In order to reduce the likelihood of this situation being perpetuated during AA3, we have deliberately taken a cautious, but nevertheless realistic, approach in assessing the level of growth related capex that Western Power may need during AA3.

Non-growth capex is not subject to the IAM and therefore any overspend on the amount allowed by the Authority will not be recovered. However, provided such overspend is shown to be prudent during an ex-post new facilities investment test (NFIT) review, it will be added to the capital base at the beginning of the next regulatory period. This limits the risk to Western Power to the financing cost of any excess non-growth capex though to the end of the regulatory period. Nevertheless, contrary to what Western Power suggested in its Amended AAI, we took into account the current state of the Western Power network and recommended in favour of Western Power where we considered there was doubt as to whether or not a particular non-growth capex item would likely be required. This is discussed further in Section 2.6.

Opex is subject to the gain sharing mechanism (GSM) and is thus the most critical expenditure category we reviewed. If the allowed expenditure is overly generous then unjustified rewards under the GSM will be gained at the expense of customers. On the other hand, inadequate opex provision will make it difficult for Western Power to maintain or improve the levels of service that it currently provides network users. In our review we generally concurred with the validity of the opex forecasting model used by Western Power but critically examined, and as a result modified, the input assumptions used. We also considered that there is ample evidence to indicate that opex efficiency gains are available to Western Power and that there should therefore be a strong incentive on Western Power to capture these gains. Efficiency gains are considered in some detail in Section 3.9.

2.3 EXPENDITURE GOVERNANCE

Section 2.1 of the Amended AAI discusses areas of consensus and discusses areas of the Draft Decision where the Authority and Western Power are in agreement. In this section Western Power notes:

> *the Authority's technical consultant observes that expenditure governance processes during the second access arrangement period were generally good and that the management of capital expenditure has improved as a result*[7].

This should not be interpreted as implying that there is no room for further improvement in Western Power's governance processes or that Western Power is currently at the industry's efficiency frontier for the management of either its capex or opex. Our Technical Report never suggested this and identified a number of areas where we considered improvement was possible[8].

2.4 IMPACT OF REVISED GROWTH FORECAST ON AUGMENTATION CAPEX

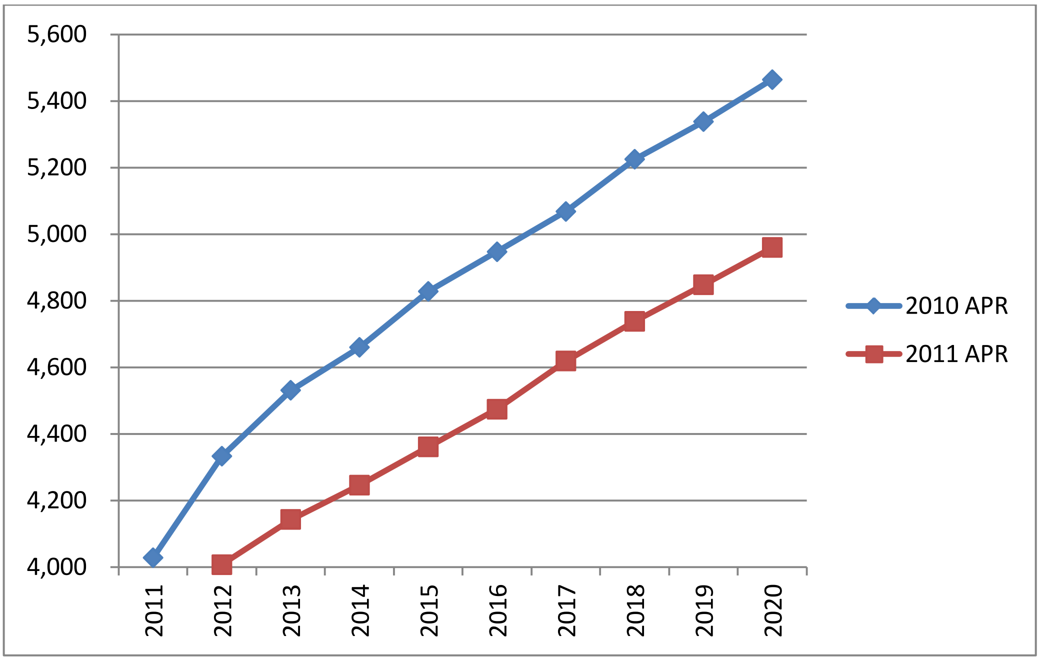
In Section 7.2 of our Technical Report we noted that:

7 Amended AAI, Section 2.1, p10.
8 Technical Report, Section 3.5, p21.

> *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[9].*

We further pointed out, with reference to Figure 2.1 below, that this is equivalent to three years' load growth and suggested that, all else being equal, this implies that the growth related capex for the final thee years of AA3 is not required.

Figure 2.1: Forecast Network Peak Demands (MW)



Source: Technical Report, Figure 7.2, p81.

In its Amended AAI Western Power argues:

> *The 2011 demand forecast, incorporates a demand increase across the five years of AA3 of 476 MW which is 61 MW (12%) less than the 537 MW of growth forecast for the same period in the 2010 demand forecast. This shows a lower growth position, but importantly the peak demand is still projected to grow at a significant rate over the AA3 period[10].*

We accept the accuracy of Western Power's analysis and note that it is not at variance with our own assessment. What Western Power is suggesting is that there is little difference between the two forecasts in the *rate* of growth in demand during AA3. This is clear from Figure 2.1 above where, after 2012, the slope of the lines depicting the two forecasts is similar.

However, Western Power appears to suggest that it is the *rate of growth in demand* over the period that determines the required augmentation capex and thus implies that *the difference in 2012 starting point demands is not relevant*. In our view, this is not the case. Augmentation capex over AA3 should ensure that by the end of the period the network has sufficient capacity to supply the *total forecast demand*, rather than the rate of growth, with an appropriate level of security. At the time of preparing its original AA3 proposal, Western Power should have been developing the network to meet the higher demand forecast for 2012 as this was the best information available to it at that time.

9 Technical Report, Section 7.2.6, p80.
10 Amended AAI, Section 8.2.1.1, p122.

Notwithstanding the deferral of some transmission projects, there is no indication that it failed to do this. The fact that the 2011 APR reduced the starting point demand simply indicates that there is some spare capacity in the network, which we consider should be utilised before additional augmentation is needed.

We note that our analysis fixed the 2011 peak demand and examined the impact of the difference in the 2018 demand in the two forecasts. It then suggested that as demand growth over the seven year period 2011-18 was reduced by 40% then the new augmentation capacity over the five year AA3 period could be reduced by the same amount. Arguably, this approach is flawed in that it attributes five years capacity expansion capex to seven years demand growth. We suggest that this results in an outcome that favours Western Power. We could have taken the position that Western Power's Original AAI[11] was predicated on the implementation of the 2011-12 approved work program, which was designed to produce a network capable of supplying the peak demand forecast for 2013 in the 2010 APR[12]. This approach fixes the 2013 POE 10 peak demand of 4,531 MW. It would suggest that, assuming the growth rates forecast in the 2010 APR, Western Power's AA3 capacity expansion capex, as presented in the Original AAI, was intended to provide for demand growth of 694 MW through to 2018 whereas the 2011 APR forecasts suggests that provision for a demand growth of only 207 MW over the same period is needed. This is a reduction of 70%.

2.5 RELATIONSHIP BETWEEN DEMAND GROWTH RATE AND CAPACITY EXPANSION CAPEX

Putting aside the discussion in Section 2.4 above, the recommended reductions in capacity expansion capex in our Technical Report were based on an assumed reduction of 40% in growth related demand. In reviewing our recommended reductions in capacity expansion capex, Western Power commented in Section 2.4.3 of its Revised AAI that:

> *…The consultant incorrectly assumes that there is a direct correlation between the decrease in forecast demand and decrease in forecast expenditure. This assumption is not appropriate as the reduction in costs is not necessarily proportionate to the decrease in demand. For example, a 40% reduction in demand would not equate to a 40% reduction in expenditure[13].*

No such global assumption was made in our Technical Report. This can be verified by examining the relative reductions in recommended capacity expansion capex and comparing these with the assumed 40% reduction in demand growth.

This analysis is shown in Table 2.1.

11 *Access Arrangement Information for 1 July 2012 to 30 June 2017:* Western Power, September 2011. This is referred to in this report as Western Power's *Original AAI.*

12 This is a simplification. As the 2013 peak demand should occur in the summer, it ignores the impact of the capacity expansion capex in the first six months of AA3. However, if the 2018 peak demand is used as the comparator, the same simplification is made in respect of the capacity expansion capex in the first six months of AA4 and the validity of the analysis is not materially affected.

13 Revised AAI, Section 2.4.3, p18

Table 2.1: Reduction in Capacity Expansion Capex ($ million real 2011-12)

	Amount	Source
Transmission		
Allowed MWEP capex	361.6	Draft Decision Table 48
Proposed AA3 fault level capex	0.4	Technical Report Table 7.2
Proposed AA3 supply capex	267.1	Technical Report, Table 7.3
Proposed AA3 thermal capex	341.2	Technical Report, Table 7.5
Proposed AA3 voltage capex	66.0	Technical Report Table 7.2
Total	**1,036.3**	
Recommended reduction for reduced demand growth	246.2	Technical Report Table 7.6
Impact of reduced demand growth on recommended capacity expansion capex	**23.8%**	
Distribution		
Proposed AA3 transmission driven distribution capex	26.8	Technical Report Table 8.5
Proposed overloaded transformer and LV cable capex	54.1	Technical Report Table 8.3
Proposed high voltage distribution driven capex	229.4	Technical Report Table 8.3
Proposed fault rating and protection capex	47.9	Technical Report Table 8.3
Total	**358.2**	
Proposed reduction for reduced demand growth	56.6	Technical Report Table 8.6
Impact of reduced demand growth on recommended capacity expansion capex (excluding MWEP)	**15.8%**	

We have included the impact of the MWEP in Table 2.1 since, even though this capex was not examined in our Technical Report, it is allowed capacity expansion expenditure in the AA3 Draft Decision and reductions in forecast demand growth in the North Country load area are included in the reduced demand forecast in the 2011 APR.

We consider that our recommended provision for reduced forecast demand growth is very reasonable from Western Power's perspective, particularly in view of the potential revised analysis discussed in Section 2.4 above.

2.6 NETWORK ASSET CONDITION

The Amended AAI references a report by GHD[14] to suggest that the Draft Decision implies an underlying assumption that the condition of the Western Power's assets is similar to the condition of the assets in the National Electricity Market (NEM) but appears somewhat confused as to whether or not this assumption also underpins our Technical Report.

For example the Amended AAI states:

> *GHD observed that the application of an economies of scale factor on Western Power by the Authority assumes that the condition of the network is similar to other businesses, **which is not the case as acknowledged by the Authority's technical consultant** (our emphasis)[15].*

However a somewhat contradictory statement is also made in the Amended AAI when it is stated:

> *GHD does not support the GBA report's direct correlation between CAPEX and OPEX for Western Power **because it appears to ignore the current condition of***

14 *Report for Review of ERA Technical Consultants Report:* GHD, May 2012. This report was provided as Appendix G of the Amended AAI.

15 Amended AAI, Section 6.3.3.1, p62.

> ***the assets** (again, our emphasis) and the minimal impact CAPEX over the AA3 period will have on OPEX liabilities*[16]*.*

Western Power has not directly compared the condition of its asset base with other network businesses in either the Original or Amended AAI, although the poor condition of the rural distribution network can be inferred from the information provided on the condition of the assets and, in particular, the need for pole replacement. We were also well aware of the legacy of network under-expenditure and noted that the forecast undepreciated transmission substation asset replacement rate was only 1.5%[17]. We believe our Technical Report appropriately recognised the relatively poor condition of the Western Power asset base and we were careful not to suggest or recommend opex or capex reductions that could potentially exacerbate this problem. For example:

- We did not recommend deferral of the Muja-Kojonup line, in part because it would replace an existing asset. We stated:

  > *Deferral of the Muja-Kojonup 132 kV double circuit line could also be considered. This project is discussed in more detail in Appendix B10 [of the Technical Report]. 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*[18]*.*

- We recommended that the $41.4 million outage duration reduction capex be allowed even though we noted that:

  > *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*[19]*.*

- We implied (but did not explicitly state) that a more consistent approach to risk management could result in asset replacement capex being reprioritised at the expense of network augmentation. We stated:

  > *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*

16 Amended AAI, Section 6.3.3.1, p59.
17 Technical Report, Section 7.4, p85.
18 Technical Report, Section 7.2.6, p82
19 Technical Report, Section B1.2, pB2.

> *with the information they need to ensure that the available funds are optimally employed for the benefit of the business and its stakeholders[20].*

What was suggested here is that Western Power should consider applying for an exemption from the Technical Rules, rather than rely on the need for strict compliance, if it believes that stakeholders would be better served if network augmentation projects were deferred and the funds and resources diverted to the replacement of existing assets that are in poor condition. Our point was that the analysis to support such a decision is not being undertaken.

The risks faced by Western Power when it defers the construction of a zone substation are compared to other business risks currently faced by Western Power, as discussed in Section 4.1.5.1 below. In Section 4.1.2.1 we also assess the risk of deferring the proposed new Cook Street – Western Terminal line and compare it to other risks that we and Western Power both consider acceptable in the normal course of business.

We recognise that the comments on asset condition in the Amended AAI relate primarily to opex and in particular to the application of economies of scale and the potential for applying an efficiency factor and we address these issues in Section 3.9. However, we note at this stage that the analysis provided in the Amended AAI and its appendices is generally predicated on continuation of Western Power's existing time-based approach to asset management, as evidenced by the statement:

> *Further, new assets are included in inspection and maintenance cycles from the time of installation[21].*

We suggest that this practice results in wasted expenditure on unnecessary inspections and maintenance interventions. Best industry practice no longer uses a time-based approach to maintenance planning, and instead is to plan maintenance using a condition-based risk management (CBRM) strategy, where inspections and maintenance interventions are focused on assets known to be in poor condition and/or where asset failure could have severe consequences. Other assets are left alone or de-prioritised. As an example such an approach would suggest that, except possibly for a limited program of random inspections to confirm that nothing unexpected was occurring, new poles would not be subjected to a full condition inspection until (say) ten years or even more after initial installation.

We are concerned that Western Power is purchasing and installing sophisticated information technology that allows industry best practice asset management procedures and processes to be put in place and that enables maintenance and asset management to be planned at an individual asset level, but does not appear to be planning to develop and, more importantly, implement the new business systems that are needed for these sophisticated tools to be fully utilised. Overall the AAI includes substantial discussion on capturing asset information but very little on how this information might best be used. Without a significant change to business systems and processes, much of the expenditure on sophisticated asset management tools will be wasted and potential savings in expenditure will not be realised.

2.7 BENCHMARKING

The Amended AAI is critical of the indicative benchmarking undertaken in Section 10.3.1.2 of our Technical Report. This criticism was based on the independent commentary on the benchmarking process provided by Wedgewood White[22].

The limitations of benchmarking discussed by Wedgewood White are well known and were discussed in our Technical Report. Because of these limitations, the findings of our benchmarking analysis informed our review, but were not relied on. Western Power

20 Technical Report, Section 3.5.3, p24.
21 Amended AAI, Section 6.1, p37.
22 *Review of Operating Expenditure Efficiency Adjustment:* Wedgewood White Ltd, 23 May 2012. This report was provided as Appendix J of the Amended AAI.

included a similar benchmarking analysis in its Original AAI[23], which it argued supported its view that Western Power's efficiency is comparable to or better than those of other Australian network service providers. We consider that most of the criticisms in the Wedgewood White report are just as applicable to Western Power's own benchmarking exercise.

We have compared our benchmarking data with the data used in Western Power's Original AAI and have found a good correlation, particularly for transmission, and using our data we have been able to identify the service providers for all the data points in the Western Power graphs. We are therefore confident in the validity of the data that we used and are satisfied that, if our analysis was repeated using Western Power's own data the analysis conclusion would be similar. The Amended AAI does not suggest otherwise.

We have the following further comments on benchmarking:

- Network service providers are primarily asset managers. Most of a service provider's opex is spent on asset management activities and therefore normalisers related to the quantity of assets under management are likely to be more valid than normalisers related to demand or electricity consumption. Like us, Western Power used line length as a benchmarking normaliser, and we consider this a good proxy for total asset quantity since, unlike asset value, it is not distorted by the average age of the asset base. For transmission systems in particular, we have found a good correlation between total opex and line length. Hence, for the purposes of the discussion in this section, we have confined ourselves to consideration of opex per line length.

- Figure 65 of the Original AAI[24] suggests that Western Power is currently almost 40% more efficient than the two most efficient (by line length) transmission network service providers (TNSPs) in the NEM, ElectraNet and Powerlink. We consider this implausible. Figure 68[25], on the other hand, shows that distribution network service providers (DNSPs) managing line lengths above 60,000 km appear much more cost effective (when normalised by line length) than smaller providers. However, Western Power appears to be 100% less cost effective than either Powercor or ETSA Utilities, both of which operate similar size networks, largely in sparsely populated rural areas. To us, this is equally implausible. We think this anomaly has been created by the impact of the expenditure that Western Power reallocated from transmission to distribution in order to validate its analysis. This appears to have resulted in Western Power's transmission costs being understated with a corresponding overstatement of distribution costs. We consider that our aggregated approach, which avoids the need for such expenditure reallocations, is more valid for this reason.

- Figure 65 in Western Power's original AAI further suggests that Western Power's transmission asset management efficiency will deteriorate by 100% over the eight year period 2008-17, while Figure 68 indicates 40% deterioration in distribution asset management efficiencies over the seven year period 2009-17. Even allowing for the limitations of benchmarking and the additional costs noted by Western Power, such as real cost escalation, new expenditure and increased use of network control services, efficiency deteriorations of this magnitude are excessive. In our view, they support the retention of an efficiency factor in the Authority's final determination. This factor is considered further in Section 3.9.

2.8 BATHTUB CURVE

The Amended AAI[26] discusses the issue of infant mortality and argues that our analysis of opex requirements ignores this issue. We accept that failure of assets early in their life is a problem for network service providers but suggest that the issue needs to be put in perspective. In this regard we make the following points.

23 Original AAI, Section 7.9, pp 161-168.
24 Original AAI, Section 7.9, p163.
25 Original AAI, Section 7.9, p165.
26 Amended AAI, Section 6.3.3.1, p55-59.

- Infant mortality is not due to age based deterioration. The Amended AAI quotes Richard E Brown who states:

  > *Newly installed electrical equipment has a relatively high failure rate due to the possibility that the equipment has manufacturing flaws, was damaged during shipping, was damaged during installation, or was installed incorrectly. This period of high failure rate is referred to as the infant mortality[27].*

  Installation related problems should be manageable by Western Power and therefore largely avoidable. The bigger issue is manufacturing problems, particularly with regard to equipment such as transformers and switchgear where a quality problem may not be observable during installation and may also not show up in commissioning tests. Measures are available to mitigate such issues. We understand, for example, that Transpower New Zealand has had few quality issues with new transformers since it changed its procurement practices in the 1990s. However, there is little Western Power can do once a faulty product is delivered. In some cases manufacturers' warranties will allow Western Power to recover some (but invariably not all) of the direct costs of infant mortality.

- In our view, the suggestion that a bathtub curve is symmetrical significantly overstates the magnitude of the infant mortality problem. The curve for pole top switch disconnectors in Figure 10 of the Amended AAI[28] is what we would consider a more typical "bathtub".

- Maintenance programs are designed to detect and manage age based deterioration rather than infant mortality. Infant mortality failures tend to be sudden and may not be detected by a standard time or condition based maintenance program. Assets known to have a high risk of infant mortality, and where the risk can be evaluated through an inspection/testing regime, could also be subjected to a special program under a well designed CBRM inspection and maintenance regime.

[27] Amended AAI, Section 6.3.3.1, p57.
[28] Amended AAI, Section 6.3.3.1, p57.

3. FORECAST OPERATIONS AND MAINTENACE EXPENDITURE

3.1 DRAFT DECISION

The allowed AA3 opex of $2,072.4 million (real, 2012) in the Draft Decision (prior to the inclusion of real cost escalation and the adjustment for system management expenditure) reflects the proposed AA3 opex in our Technical Report except for the following two further adjustments made by the Authority:

- the Authority removed $66.2 million network control services (NCS) opex from the regulated revenue cap forecast; and
- the 2% efficiency adjustment was applied from 2012-13 rather than 2013-14 as proposed in our report.

It is important to note that the Authority did not disallow the NCS expenditure – it merely removed it from the revenue cap. It intended that Western Power would still be able to recover this expenditure outside of the revenue cap to the extent that it is found to be prudent[29]. Hence the Draft Decision opex reduction is not as high as the 19.2% indicated by Western Power in its Amended AAI[30]. Ignoring the impact of real cost escalation, which we do not consider in this report, the total opex requested by Western Power was $2,460.0 million excluding network control costs. Hence the Draft Decision reduction to Western Power's forecast opex was $387.6 million or 15.8%.

3.2 BASE YEAR ADJUSTMENTS

In our Technical Report, we reviewed the efficiency of the opex in Western Power's chosen 2010-11 base year and made a number of downward adjustments to individual line items to arrive at a revised base year opex amount that we considered efficient. However Western Power commented in its Amended AAI that:

> *Western Power's concern is that this approach results in only downward adjustments to Western Power's cost base. It does not account for activities that have decreased relative to history. Western Power has identified 10 of the 77 recurrent operating expenditure activities that decreased during this period.*
>
> *Furthermore, the Authority's technical consultant ignores the inherently variable nature of individual operating expenditure line items or activities. Volatility in individual operating and maintenance activities between years is common. This is rare at the regulatory category level and even less frequent at the aggregated operating expenditure level[31].*

This argument overlooks the magnitude of the increase in opex between 2009-10 and the 2010-11 base year. In the base year, Western Power's actual opex was $415.5 million, an increase of $43.4 million or 11.7% over the previous year. An expected increase assuming no economies of scale or efficiency gains, and also no new expenditure, was approximately 2% for growth and 3.6% for inflation or a cumulative increase of only 5.7%. As the actual increase was more than twice what was to be expected from this high level indicative analysis, and significantly greater than the expected impact of real cost escalation, it was necessary for our review to examine in some detail the efficiency of the actual base year expenditure and perhaps inevitable that any adjustments would be down rather than up. We note that the direct base year opex used in our Technical Report scale escalation model was only 1.2% lower than the equivalent opex used by Western Power for its forecast, much less than the 6% downward adjustment that the above high level analysis might suggest.

In Sections 3.2.1-3.2.4 below we look at those base year adjustments in our Technical Report that Western Power does not accept. We have not reviewed the $10.3 million

29 NCS is discussed further in Section 5.3.2 of this report.
30 Amended AAI, Section 2.4.2, p15.
31 Amended AAI, Section 6.3.1, p48.

system management adjustment to transmission network operating expenditure as this adjustment was not included in the opex model used in preparing our Technical Report. It was shown as a separate line item in Table 36 of the Draft Decision.

3.2.1 Corrective Deferred and Corrective Emergency Maintenance

In its Original AAI Western Power added $3.0 million to its actual base year opex "Distribution Corrective Emergency" line item since it considered its actual expenditure in that year was abnormally low[32]. We accepted that an upward adjustment was appropriate but considered the amount proposed by Western Power to be high and reduced the adjustment to $2.3 million[33]. Determination of an appropriate reduction was complicated by Western Power's advice that the reported actual expenditure in the previous year was higher than it should have been because of timesheet recording issues.

In its Amended AAI, Western Power accepted our analysis in principle but considered that our assumed indirect cost allocation was excessive. This had the effect of reducing the magnitude of the adjustment indicated by our analysis. Western Power noted that it had already given us the actual indirect cost component and recalculated the required adjustment, using our analysis methodology, to $2.83 million[34].

We are unable to replicate Western Power's analysis, which was not included in its Amended AAI. We accept that it provided the actual indirect cost allocations in its scale escalation model and have reworked our own analysis using these numbers. Western Power's scale escalation model shows that for the 2010-11 base year, the actual opex including indirect costs for "corrective deferred" and "corrective emergency" maintenance was $98.89 million, as shown in Table 10.4 of our Technical Report. With indirect costs excluded the actual opex was $82.67 million. Indirect costs therefore amounted to 16.4% of total costs, higher than the 14.0% assumed in our Technical Report analysis.

Table 3.1 below replicates the analysis in Table 10.4 of our Technical Report, with indirect costs assumed to be 16.4% of total costs rather than 14.0%.

Table 3.1: Efficient Opex Analysis for Corrective Deferred and Corrective Emergency Maintenance ($ million, real 2011-12)

	2009-10	2010-11	Technical Report 2010-11
Corrective Deferred (Actual)	20.6	28.0	28.0
Corrective Emergency (Actual)	79.0	70.9	70.9
Total (Actual)	99.6	98.9	98.9
Indirect Cost Component of Total	16.3[1]	16.2[2]	13.8[3]
Total Direct Costs (Actual)	83.3[4]	82.7	85.1
Efficient Cost (2.00% escalation)	83.3[4]	85.0	87.4

Source: Western Power and GBA.
Note 1: 16.4% of total cost. In the Technical Report analysis this was $13.9 million or 14.0 % of the total cost.
Note 2: 16.4% of total cost.
Note 3: 14.0% of total cost.
Note 4: In the Technical Report analysis this was $85.7 million, the difference between the total actual cost of $99.6 million and the assumed indirect cost of $13.9 million.

The appropriate base year adjustment in the updated analysis is $2.3 million, which is the difference between the assessed efficient cost of $85.0 million and the actual cost of $82.7 million. Hence while the absolute values of the 2010-11 actual and efficient costs were different in the two analyses, the difference between them, which determines the adjustment amount, was the same. We conclude that no adjustment to the analysis in our Technical Report is necessary.

[32] Original AAI, Section 7.2.1, Table 28, p134.
[33] Technical Report, Section 10.3.1.3.1, pp116-117.
[34] Amended AAI, Section 6.3.1.1, p49.

3.2.2 Data Correction

In our Technical Report we reduced the base year cost of Western Power's routine data correction program by $2.3 million to reflect Western Power's indication of the average annual cost of this program[35]. In its amended AAI Western Power stated:

> *In AA3, Western Power will undertake targeted asset data cleansing projects for switch wires, conductors and underground assets. While these projects relate to different assets to those addressed in 2010/11 and 2011/12, the nature of the work will not change. This means recent expenditure on these projects is representative of the expected level of expenditure in AA3. Expenditure on these specific projects is expected to conclude once Western Power's asset data has been improved.*
>
> *Western Power accepts the Authority's approach and has reduced recurrent base year costs by $1.68 million. It has then added project specific costs of $1.1 million for each year of AA3 in the category of 'one-off adjustments'[36].*

Western Power appears to be saying that this targeted data cleansing program is separate from, but will be undertaken at the same time as, the comprehensive field survey data capture project. This appears very inefficient and we see no reason not to integrate this limited targeted program with the more comprehensive data capture project. The integrated approach is unlikely to materially impact the cost of the data capture project and we are satisfied that the forecast provision for this program in our Technical Report is sufficient to fund Western Power's routine data cleansing requirements during AA3.

3.2.3 Environmental Cleanup

In our Technical Report we reduced the base year opex for environmental cleanup from $1.2 million to $0.8 million, the average expenditure over AA2[37]. We noted that the base year 2010-11 spend was 400% higher than the previous year and 30% higher than the expected annual expenditure in 2011-12. We also expressed surprise that Western Power was still incurring PCB disposal costs as in many jurisdictions PCB contaminated equipment was required to be proactively identified and removed and in these jurisdictions this process was now complete.

Western Power commented:

> *PCB is hazardous and the disposal of contaminated equipment is required to be undertaken. The majority of this was done through the 1980s and 90s. However, in Australia, there was a minimum threshold below which assets contaminated could stay in use until the end-of-life. It is expected that the 2010/11 level of PCB disposal will continue throughout AA3, in line with Western Power's increasing asset replacement program.*
>
> *Consequently, Western Power will continue to correctly dispose of assets containing hazardous PCBs and has not reduced the 2010/11 recurrent base year value for environmental cleanup costs[38].*

We accept this position. However our proposed provision of $0.8 million is 167% higher than the actual expenditure in 2009-10 and only marginally below the expected 2011-12 spend. This is not a large expenditure item and we consider that reducing the base year expenditure to $0.8 million is still reasonable.

35 Technical Report, Section 10.3.1.3.2, pp117-118.
36 Amended AAI, Section 6.3.1.2, p50.
37 Technical Report, Section 10.3.1.3.5, pp 119-120
38 Amended AAI, Section 6.3.1.3, p50.

3.2.4 Substation Battery Maintenance and Inspections

In our Technical Report we proposed a $0.8 million reduction in the base 2010-11 cost for substation battery maintenance and inspections[39]. In its Amended AAI, Western Power rejected the methodology we used to arrive at this assessment. It stated:

> *Western Power informed the consultants that there had been a change in accounting for substation battery maintenance & inspections and substation primary plant. Western Power advised that this accounting change means that expenditure on substation battery maintenance and inspections should be considered in aggregate with transmission substation inspections. Instead, the Authority's technical consultant has added expenditure for substation battery maintenance and inspections with substation primary plant.*
>
> *When the correct expenditure types are added together, expenditure on substation battery maintenance and inspections and transmission substation inspections in 2010/11 is in line with historical expenditure. Therefore, Western Power has not amended the 2010/11 recurrent base year value for substation battery maintenance and inspections[40].*

The line item "transmission substation inspections" was not included in the opex breakdown provided for our review, although it was included as activity K1X16 in the more disaggregated breakdown in Western Power's scale escalation model. However, as the scale escalation model only gave actual costs for 2010-11 and not for the other years of AA2, we have no way of verifying Western Power's position.

3.3 NEW RECURRENT EXPENDITURE ADJUSTMENTS

In this section we consider additional adjustments and expenditures that Western Power now proposes be incorporated into the scale escalation model. These costs were not included in the model Western Power used for the Original AAI and were therefore not allowed for or considered in the Draft Decision.

3.3.1 Pole Maintenance

Western Power has increased the contractor unit rates for its pole maintenance program to reflect an increase in rates as a result of contract renegotiations in September and October 2011. These negotiations resulted in rates over and above those estimated by Western Power due to:

- labour rate increases above CPI arising from market resource constrained in the face of increasing demand;
- increase in capital expenditure set up costs in line with work delivery growth requirements; and
- risks being borne by the contractors as a result of uncertainty over work programming and work delays.

Western Power estimates the impact of this increase on its pole maintenance opex to be $2.3 million per year[41]. We have insufficient time or information to comment in detail on the validity of the analysis leading to the annual $2.3 million additional cost estimate or on whether or not Western Power made all reasonable efforts to minimise the increase in negotiating with its contractors.

We suggest that Western Power must take responsibility for uncertainty over work programming and work delays, particularly in an environment where there are large backlogs and deliverability is the main constraint, as indicated in the second of the above

[39] Technical Report, Section 10.3.1.3.7. p121.
[40] Amended AAI, Section 6.3.1.4, p51.
[41] Amended AAI, Section 6.3.2.1, p52.

bullets. This is consistent with the view, reflected in the GHD Asset Management Audit Report[42], the Parliamentary Inquiry Report[43] and our own Technical Report, that there is significant room for improvement in the efficiency with which Western Power manages its work program, particularly with respect to wood pole maintenance and replacement. We note that in the Amended AAI[44], Western Power has indicated that it has moved to mitigate this programming risk and implied (but not explicitly stated) that this improvement was taken into account by the contractors in agreeing the above rates.

Nevertheless, we consider a $2.3 million increase is not unreasonable in an environment where the contractors clearly held the balance of power in rate negotiations. While the Amended AAI[45] indicates that this adjustment is applied to the base year, Western Power's scale escalation model subsequently provided to the Authority applies the adjustment as a recurrent step change in 2012-13. We think this latter treatment is appropriate.

3.3.2 Bundled Pole Inspections

Western Power has increased its forecast annual expenditure on bundled pole inspections by $3.8 million to allow for an increase in volumes as a result of the implementation of its new wood pole management plan, which is currently under review by EnergySafety[46]. Western Power's latest scale escalation model further indicates that part of the increase is due to the increase in contractor unit rates discussed in Section 3.3.1.above.

Western Power's new pole management policy now states:

> *All unreinforced hardwood poles over 25 years old are considered to be at risk of unassisted failure and will be reinforced, replaced or removed[47].*

This is a significant change from Western Power's policy at the time of submitting its original AAI and we understand it has been developed in consultation with EnergySafety. Poles in this category represent a substantial majority of Western Power's wood pole assets. The decision that these poles will now be reinforced, as a minimum and irrespective of below ground wood condition, means that below ground inspection of these poles is no longer necessary as Western Power's current reinforcing techniques have sufficient strength to support poles below ground level irrespective of the condition of the pole beneath the ground. Hence it is only necessary to inspect the wood condition above ground level in order to confirm that the pole would have sufficient strength above the ground to carry the required load. EnergySafety has informally confirmed this to us.

All else being equal, elimination of the need to dig and drill poles in this category below ground level can be expected to reduce pole inspection costs. It is not clear whether these savings were factored in when Western Power revised its forecast pole inspection costs upwards to allow for higher contractor unit costs and greater inspection volumes.

Notwithstanding this we do not propose a reduction in Western Power's revised forecast for this line item because of Western Power's pole maintenance and asset replacement backlog, as any surplus in pole inspections could usefully be reallocated to other priority areas within the broader wood pole management effort. We think that at this stage the focus needs to be on the efficiency of implementing the pole management program, particularly the management of older hardwood pole assets, and that this is best assessed through an ex post review at the time of the AA4 revenue reset.

While the Amended AAI indicates that this adjustment is applied to the base year[48], Western Power's scale escalation model subsequently provided to the Authority applies

42 *Western Power Asset Management System Review Final Report,* GHD, October 2011.

43 *Unassisted Failure,* Report 14, Standing Committee on Public Administration, Legislative Council of Western Australia, January 2012.

44 Amended AAI, Section 8.2.2.2, p134.

45 Amended AAI, Section 6.3.2, Table 12, p52.

46 Amended AAI, Section 6.3.2.2, p52.

47 *Policy for Managing Hardwood Poles in Western Power's Electricity Transmission and Distribution Networks:* Western Power. June 2012, Section 4, p4. (Western Power ref DMS# 9204170).

the adjustment as a recurrent step change in 2012-13. We think this latter treatment is appropriate.

3.3.3 Wood Pole Testing Facility

Western Power has included an additional $1.4 million in its scale escalated opex model for the operating cost of a new wood pole testing facility[49]. EnergySafety has indicated to us that it supports this initiative, although it notes that the facility need not be overly elaborate since a Western Power operated facility could not be used for forensic pole testing in legal and insurance liability cases because of conflict of interest concerns.

The $1.4 million cost is based on an independent estimate by Alliance Power and Data[50]. While the Amended AAI states that that the adjustment was made to the 2010-11 recurrent base year it was actually included in Western Power's scale escalation model as a recurrent step change from 2013-14. We think this latter treatment is appropriate.

3.3.4 Management of SF_6 Gas

The Amended AAI[51] comments that, at the time of preparing the original AA3 submission in September 2011, Western Power had not been able to assess the impact of the Government's Clean Energy Future Package on its operations. Since this time, Western Power has been able to better understand the implications of this package and has revised its operating expenditure forecasts accordingly. The *Ozone Protection and Synthetic Greenhouse Gas (Manufacture Levy) Amendment Act 2011*, which forms part of the Clean Energy Future package, imposes a carbon price on the manufacturing and importing of sulphur hexafluoride (SF_6) gas. Western Power further states that, consequently, it has revised recurrent opex forecasts upwards by $0.8 million to account for the impact of increased costs in purchasing and replacing SF_6 gas to maintain Western Power's transmission filled switchgear.

In principle, we think such an adjustment is reasonable to the extent that the Clean Energy Future package imposes additional operating expenditure on Western Power. However, we note that the step change should commence from 2012-13 since the package does not become effective until 1 July 2012.

3.4 SCALE ESCALATION

Western Power's Amended AAI[52] raised two key issues in respect of the scale escalators used. Firstly it argued that the network size scale escalator should be based on forecast growth rather than historic growth. It argued there was no capex-opex trade off and cited the issue of infant mortality and the bathtub curve to support this. Secondly it argued that no economy of scale factors should be applied. Its supporting arguments included the submission that efficiencies that it had made to date had already captured all economies of scale available to it and also that, as its network was in a poor condition compared to other Australian service providers, additional maintenance expenditure was required rendering any economy of scale moot. We address these arguments in the following sections.

3.4.1 Selection of Scale Escalator

In its Original AAI, Western Power used a network scale escalator of 3.42% per annum based on its forecast growth[53], whereas in our Technical Report we used an escalator of 2.1% based on the network growth rate over the period 2007-11[54].

48 Amended AAI, Section 6.3.2, Table 12, p52.
49 Amended AAI, Section 6.3.2.3, pp 52-53.
50 Amended AAI, Appendix Z. This report is confidential.
51 Amended AAI, Section 6.3.2.4, p53.
52 Amended AAI, Section 6.3.3, pp 54-63.
53 Original AAI, Section 7.2.1, p136.
54 Technical Report, Section 10.4.1, pp121-123.

In examining the growth rates assumed by Western Power we noted that the growth in forecast customer numbers, based on an independent report by Deloitte, and the forecast increase in line length was similar to historic growth rates. However both distribution transformer numbers and forecast zone substation capacity were forecast to increase at significantly higher growth rates[55]. Western Power did not explain the reason for the number of distribution transformers increasing at a higher rate than customer numbers or why line length and the forecast zone substation transformer capacity at the end of AA3 was much higher than indicated in other information provided by Western Power. Had we accepted that the scale escalator should be based on forecast growth rates, we would have adjusted the Western Power assumptions downward to account for these anomalies. We would then have made an additional adjustment to account for the reduction in network augmentation capex as a result of the lower POE 10 demand forecast in the 2011 APR.

In the scale escalation model for its Amended AAI, Western Power has reduced the average network growth escalator to 3.18% for the transmission network and 3.13% for the distribution network. It has also broken down the escalators by year and used a separate escalator for each year[56]. This has the effect of reducing the overall impact of the escalator since network growth in the early years of the period is low. Leaving aside the issue of whether scale escalators should be based on actual or forecast growth rates, we first examine the validity of the network growth data used by Western Power as the basis for the escalators in its Amended AAI scale escalation model. This data is shown in Table 3.2, which shows only the data at the end of AA3 on the basis that Western Power has, presumably, assessed the augmentation requirements in the Amended AAI to ensure that the network has sufficient capacity to meet the forecast peak load at the end of the planning period.

Table 3.2: Growth Escalator Drivers

	2016-17	Change
POE 10 Forecast Peak Demand (MW)		
2010 APR	5,068	
2011 APR	4,619	(8.8%)
Customer Numbers		
Original AAI	1,162,284	
Amended AAI	1,176,448	1.2%
Transmission Line Length (km)		
Original AAI	7,782	
Amended AAI	7,985	2.6%
Distribution Line Length (km)		
Original AAI	96,396	
Amended AAI	96,512	0.1%
Number of Distribution Transformers		
Original AAI	77,443	
Amended AAI	76,869	(0.7%)
Zone Substation Transformer Capacity (MVA)		
Original AAI	10,739	
Amended AAI	10,218	(4.9%)
Response to Question GB20	8,514[1]	

Source: GBA analysis of data provided by Western Power in its scale escalation spreadsheets.

Note 1: This information was provided as a result of Question GB20 to Western Power during the original review. It relates to the augmentation of the network to meet the APR 2010 demand forecast and aligns well with the more detailed information provided by Western Power on its

55 Technical Report, Section 10.4.1, pp121-123.

56 The scale escalation factors used in the revised scale escalation model are shown in the Amended AAI, Table 14, p60.

planned augmentation projects. This figure is taken from Western Power's updated response to this question.

We have the following comments on the data in Table 3.2.

- The 2016-17 POE 10 forecast peak demand in the 2011 APR reduced by 8.8% and we assumed that, for the purposes of its Amended AAI, Western Power revised its network augmentation plan to allow for this reduction. We would have expected this to have resulted in reduced network size. Notwithstanding this, Western Power has *increased* its forecast growth rate for three of the five scale indicators. For those indicators where the growth rate is reduced, the reduction is much lower than the forecast reduction in the rate of growth in demand. With the possible exception of zone substation transformer capacity, we find these results counter-intuitive.

- In forecasting increased customer numbers, Western Power has not used the findings of the independent Deloitte report submitted as Appendix T to its Original AAI. It has provided no explanation for this. While not shown in Table 3.2, the actual customer numbers provided in the Amended AAI for 2010-11 and 2011-12 are lower than in the Deloitte report. This indicates that customer growth in the last two years has been lower than expected, a trend that Western Power anticipates will now reverse. It also has provided no explanation for this expected change in the current trend and we think such a reversal is unlikely given the present economic outlook, both internationally and within Australia (particularly outside of the mining sector).

- We are unable to reconcile Western Power's transmission line length forecast with the limited number of transmission line construction projects proposed during AA3. We note that many of the new transmission lines projects included in the AA3 capex forecast Mid West Energy Project, the South Metro 132 kV reconfiguration and the Muja-Kojonup double circuit line will replace existing lines that will be decommissioned once the projects are completed.

- The magnitude of the reduction in zone substation transformer capacity is credible if it is accepted that the utilisation of zone substations is high and that expenditure is required to address this. However the variance between the total capacity assumed by Western Power in its scale escalator analysis and the corresponding information provided during our original review means that, without additional clarification, we must treat this data as suspect.

We conclude from the above high level sanity checks that the input data used by Western Power in the derivation of its scale escalators is not sufficiently robust to be relied on by the Authority for the purposes of its revenue cap analysis. As an alternative approach, we consider the growth in demand that Western Power must provide for in its network augmentation planning during AA3. Consistent with the discussion in Section 2.4, we assume that, prior the start of AA3, the network had sufficient capacity to meet the APR 2010, POE10 demand forecast for 2012. While Western Power does not accept this as a valid assumption for expenditure planning, we consider it reasonable as the 2011 APR was not available at the time Western Power needed to plan and the network capacity to meet its forecast 2012 peak. Hence, during AA3 Western Power will need to augment the network to supply a forecast POE 10 demand that increases from 4,333 MW in 2012 (based on the APR 2010 demand forecast) to 4,738 MW in 2018 (based on the APR 2011 demand forecast). This represents a growth rate of 1.5%, much lower than the scale escalator growth rate we used in our Technical Report.

We are not proposing that the Technical Report scale escalation factor of 2.1% be further reduced as we acknowledge that:

- transmission line investment tends to be "lumpy" rather than incremental;

- Western Power must design its network to accommodate both generator and load connections;

- forecasts are inherently uncertain; and
- there is a likely need to augment some parts of the network to improve supply security.

However we are satisfied that the 2.1% we proposed is reasonable in that it is adequate to cater for Western Power's unavoidable network augmentation requirements and also to provide a reasonable buffer that will allow Western Power to improve its existing level of supply security and deal with the unexpected.

3.4.2 Economies of Scale

As noted in Section 3.4 above, Western Power does not accept that it is reasonable to include an economy of scale factor in its scale escalation model. We address its arguments for this below.

3.4.2.1 Benchmarking

Western Power has introduced our benchmarking analysis into its discussion on the validity of economies of scale, even though we did not suggest that benchmarking was relevant to this issue. It stated:

> *The Authority's approach to economies of scale is internally inconsistent with its benchmarking analysis. If the Authority is to rely on its technical consultant's benchmarking analysis, which assumes linear relationships with costs and each normaliser (RAB, network length and customer numbers), then it is not reasonable to apply an adjustment for economies of scale. The normalisation was undertaken on a linear basis, that is, it implicitly assumes that operating expenditure is linearly related to each of these factors. If the benchmarking holds, and relationships are linear, then there can be no economies of scale.*
>
> *The Authority's technical consultant's benchmarking also provides no evidence to assume that increased size leads to lower unit costs. Geoff Brown and Associates' analysis suggests that there are no economies of scale that flow from the physical size of the network or customer base. If there was, New South Wales and Queensland would have the two most efficient networks which is not the case as outlined in Table 15 [of the Amended AAI], which reproduces the benchmarking relied on by the Authority's technical consultant[57].*

We accept in principle that there is a relationship between cost and network size in that as network size increases then costs will also increase. However the benchmarking analysis in our Technical Report was not undertaken to establish the nature of this relationship. As discussed in Section 2.7 above, its primary purpose was to critically examine Western Power's claim in Section 7.9 of the original AAI that its costs are comparable to those of other service providers in Australia and in particular its claim in Figure 65 of the Original AAI that its transmission network operating efficiency is at least 30% better than that of any transmission service provider in the NEM, when normalised against transmission line length. Our view was (and still is) that this claim is not credible and because of this we considered Western Power's own benchmarking analysis merited further scrutiny.

We note that benchmarking is a commonly used tool in regulatory economics and that the normalisers we used, notwithstanding their limitations, are generally accepted and used within the industry. We also comment that the AER does not appear to share Western Power's view that these normalisers are incompatible with the application of economies of scale. It publishes comparative benchmarking data of the service providers it regulates both in its regulatory decisions and performance reports while, at the same time, it requires economy of scale factors to be incorporated into opex forecasts developed using a scale escalation approach, as discussed further in Section 3.4.2.2 below.

[57] Amended AAI, Section 6.3.3.1, p61.

3.4.2.2 Application of Scale Economies by the AER

Western Power submits that the AER has not universally applied to decisions where scale escalation was applied and it provides examples to support this statement[58]. Three of these examples relate to gas and only one to electricity. We are reluctant to use gas decisions as precedents because of the differences between gas and electricity networks, including the fact that a gas network incorporates a degree of storage that is not available in an electricity network. The only electricity network cited was the AER's Transend decision in 2009.

However, Western Power's submission that scale economies were not included in the Transend decision is inaccurate. Transend's opex forecast was reviewed by Worley Parsons, which concluded:

> *The asset growth factors (**with associated economy of scale factors** (our emphasis)) were consistent with the methodology employed elsewhere (and approved by the AER)[59].*

Also, the application of economy of scale factors is discussed in some detail in the AER's Transend Draft Decision[60]. There is no reference to economies of scale in the Final Decision (which is likely the reason why Western Power has mistakenly suggested that they were not applied) but there is nothing to indicate that the AER's view on application of economies of scale had changed.

We conclude that the AER, as a matter of course, requires opex forecasts used in electricity network price determinations to make appropriate provision for economies of scale.

3.4.2.3 Other Issues

In its Amended AAI Western Power raised other concerns about the use of economy of scale factors in its opex forecasting. It states:

> *Western Power considers that using the additional economies of scale adjustment that the Authority proposes is likely to overestimate Western Power's ability to reduce costs over AA3. This is because:*
>
> - *the current state of the network drives a greater volume of operating and maintenance activity giving rise to diseconomies of scale which is likely to continue until Western Power achieves a sustainable rate of investment and stable asset condition*
> - *a large proportion of operating expenditure is reactive and therefore unable to be grouped in like work types or locations, the dispersed nature means that diseconomies of scale is experienced*
> - *economies of scale achieved through AA1 and AA2 initiatives of grouping planned activities and maintenance is already incorporated into Western Power's base year and therefore has been rolled forward under the scale escalation approach*
>
> *The network's condition is deteriorating at a faster rate than growth in the size of the network. At the end of the AA3 period the average network asset age will be greater than the average network asset age at the commencement of the AA3 period …[61]*

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58 Amended AAI, Section 6.3.3.1, p63.

59 *Review of the Transend Transmission Network Revenue Proposal 2009-2014. An Independent Review Prepared for the Australian Energy Regulator:* Worley Parsons, 23 October 2008, Section 1.4.3, p13.

60 *Draft decision, Transend transmission determination 2009-10 to 2013-14:* Australian Energy Regulator, 21 November 2008, Section 6.5.5, pp176-179.

61 Amended AAI, Section 6.3.3.1, p62

And further:

> *The specific nature of Western Power's operating activities and operating obligations mean that additional scale economies beyond those already achieved to date (and therefore reflected in Western Power's base costs) are unlikely during AA3 and in many cases, Western Power may, experience diseconomies of scale.*
>
> *Where economies of scale have been achieved, Western Power has incorporated these in its base forecasts. Western Power has introduced a number of initiatives over the AA1 and AA2 period to optimise planned capital and operating activities, allowing Western Power to realise available economies of scale[62].*

Western Power appears to be suggesting that it has already captured all available economies of scale during AA1 and AA2 and no further economies are available. We reject this and note the AER is still requiring economies of scale in regulatory decisions on electricity networks even though the application of incentive based regulation is significantly more mature in the AER jurisdictions than in Western Australia. We note also that there are a number of cost items in the scale escalation model, such as software licences[63] and environmental cleanup, where the cost is not a function of network size.

Western Power has provided no substantive or objective analysis comparing the age or condition of its network with that of other network service providers although anecdotal evidence would suggest that its assessment of the relative state of the Western Power network is reasonable, particularly with respect to the distribution network. For this reason we have not suggested reductions in the proposed Western Power's asset replacement capex. However, Western Power appears to be suggesting that any potential economies of scale would be offset by the increase in the cost of maintaining older assets. We note that there is no direct or causal link between the two factors. We also point out that the base year costs used in the model are based on actual costs that should already take due account of the state of the existing network.

3.4.2.4 Conclusion

In this Section 3.4.2 we have considered the arguments put forward by Western Power with regard to economies of scale and have seen nothing to lead us to conclude that either the use of economies of scale, or their magnitudes as applied in the scale escalation model that formed the basis for our Technical Report, were inappropriate.

3.5 NON-RECURRENT EXPENDITURE

In the sections below we consider further the non-recurrent opex adjustments in the Draft Decision that Western Power does not accept. As noted in Section 3.1, we have not considered the removal of System Management's network control opex, which the Amended AAI places in this category.

3.5.1 Field Survey Data Capture Project

Our Technical Report proposed that the forecast cost of the field survey data capture project be reduced by 50%. We stated:

> *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*

62 Amended AAI, Section 6.3.3.1, p63.

63 In Section 10.4.4 of our Technical Report we allowed a step change of +$1.0 million from 2012-13 to accommodate the new Clarity/Oracle licences for this in our model, but 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. In our model for this report (see Section 3.8) we have applied scale escalation to this cost, even though Western Power accepted our initial treatment, since we now consider that not to apply scale escalation would be inconsistent with the application of economies of scale.

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 [of our Technical Report], 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[64].

In refuting the arguments we made[65], Western Power has relied on a so-called "business case" provided as confidential Appendix B to the Amended AAI. However this document is not a business case in the generally accepted meaning of the term, as it virtually ignores alternative options and focuses on justifying Western Power's preferred alternative as being the only acceptable solution. We trust that Western Power's Board requires a much more detailed and balanced analysis of the merits of all potential alternatives before approving major expenditure proposals and note the concerns we raised in Section 3 of our Technical Report on the quality of some of the business cases we have seen[66].

We do not intend to undertake a detailed analysis or rebuttal of Western Power's comments but we make the following observations:

- Notwithstanding our proposed 50% reduction, there is still $17.15 million left in the forecast for data survey and capture. This is a significant sum and sufficient to fund a project either comparable to or larger than three of the four comparator projects identified in Table 2 of Western Power's "business case". The fact that we have recommended a reduction to Western Power's original scope should not to be taken to indicate that we don't recognise the seriousness of the issue or that we don't consider that a project of significant magnitude may be required to address it.

- We acknowledge Western Power's comments regarding further data capture work by its peer service providers…

  Western Power understands that most eastern states utilities have new large scale data capture activities either planned or currently underway. Western Power was not able to confirm the scale and scope of these activities[67]…

  …but note that such comments are hearsay and fall well short of the standard of argument that the Authority should take into account when making regulatory decisions.

- The real issue that should determine the scope of the data capture project is the condition of the existing database. Western Power has undertaken a number of pilot programs but has not provided any quantitative analysis of these. Instead it has relied on adverse comments by EnergySafety and in the Parliamentary Standing Committee report, as well as selected examples (which may well be atypical) to support its case and justify the project scope. We note that both EnergySafety and the Parliamentary Inquiry Report were focused on wood pole management and that the comments on data inaccuracies were made in this

64 Technical Report, Section 10.6.2.1, p128.
65 Amended AAI, Section 6.3.4.1, pp64-68.
66 Technical Report, Section 3.2.1, pp 14-15; Section 3.5.3, pp23-24.
67 Amended AAI, Section 6.3.4.1, pp67.

context. We do not think these comments should be interpreted as providing a balanced view of asset data accuracy across the entire asset base. We consider that using such reports out of context creates a risk of over-reaction and, consequently, wasted expenditure.

- A more balanced view of the condition of the existing database is provided in GHD's asset management audit report, which indicated that timely recording of data changes was a more serious problem. As acknowledged by Western Power, the GHD report generally supported the comments we made on data capture in our Technical Report. In respect of the scope of any data capture project the GHD report noted:

> *During our discussions with Western Power's asset management staff during the AMSR project, the lack of legacy data had been evident in the databases for many years and although the condition assessment process had included capturing missing data (such as the installed dates), the data in Western Powers systems had not been updated. For example, installed dates were missing on at least 2% of the 400 pole records and default dates were recorded in at least 5% of the sample recorded reviewed. We had discussed using the planning approval records or adjoining pole installed dates as suitable default date with the IT staff, who agreed that this would be a very good idea and that additional field inspections should not be needed*[68]*.*

These comments by GHD relating to the accuracy of pole installation dates do not indicate a serious situation requiring precipitate action. Firstly the comments do not identify an issue with 93% of the data set. They also indicate that many of the problems in the remaining 7% of the data records could be satisfactorily addressed in a very cost effective way without the need for a systematic field inspection of all poles.

While we accept that the above interpretation of GHD's report may understate the magnitude of the data accuracy problem, and the effort required to fix it, we have seen nothing to indicate that a systematic data capture of the scale proposed covering all of Western Power's distribution line assets is necessary. A possible alternative approach would be to give Western Power's pole inspection contractors copies of asset records and require them to assess, as part of the inspection process, whether or the record on an individual asset is fit for purpose. We think that asset inspectors, possibly with a little training, should be well capable of doing this and that the incremental cost of including such an assessment in the inspection program would be small. When inaccuracies are identified the asset inspector would not be required to correct the record, but simply to tag it for follow-up field verification by Western Power's specialist data verification contractors.

Such an approach could provide a data set that was fit for purpose after one inspection cycle at a much lower cost than Western Power currently proposes, because data on assets with records of sufficient accuracy to be fit for purpose would not be recaptured. However this possible alternative option has not been identified in the "business case". If this process was put in place permanently it would become a feature of Western Power's asset data maintenance strategy and go some way to addressing what appears to be a significant gap in its current and proposed procedures.

This approach should also find missing poles provided Western Power's inspectors worked systematically though the network. Missing poles are not randomly scattered across Western Power's service areas but are components of existing lines that form part of the network. If a pole inspector inspecting a section of the network comes across a pole for which there is no corresponding asset record, this could also be flagged for later follow-up.

We note further that Western Power's base year opex reflects the efficiency with which it currently implements its maintenance plan and this in turn is partly a function of the

[68] *Report for Review of ERA Technical Consultants Report:* GHD, May 2012, Section 3.1, p4.

current state of its asset records. Improvements in its asset records should generate efficiency gains that have not been allowed for in Western Power's asset forecast.

We are suggesting that Western Power is focusing on a gold-plated solution and the additional benefits such a solution provides, without objectively establishing the incremental value of these additional benefits and whether this incremental value outweighs the extra capital cost. Because of this, it may not be making a good decision.

We have proposed a 50% reduction in the scope of the project. Due to our lack of information, this reduction is arbitrary and unlikely to accurately reflect an optimum project scope. We think Western Power should reanalyse this project objectively. It may find that the benefits it really needs could be captured at an even lower cost than we have proposed, in which case the savings will be magnified through the gain sharing mechanism. On the other hand it may decide that our 50% reduction is excessive and that a higher scoped project does provide real value. In this case the benefit-cost ratio will be greater than 1 and Western Power should proceed with a more extensive project and fund the additional cost from the value of the benefits it provides. It should also consider the development of robust procedures to ensure that captured data is properly maintained as part of the project design, and not leave this until the after the data collection project is finished or even well underway.

3.5.2 Network Control Services

In our Technical Report we made no proposal or recommendation on the treatment of NCS. However we noted that[69]:

- Western Power could recover the actual cost of NCS through the provisions of clause 6.76 in the Access Arrangement, provided that the expenditure was found to be prudent;

- It was very difficult to forecast in advance the required expenditure for NCS. While capacity costs are predictable, a large portion of the actual expenditure will be to cover the cost of fuel. This will depend both on a very volatile international oil price and also on the actual amount of energy generated, which in turn will depend on actual customer demand; and

- The regulatory risk strongly favours Western Power in that, if there was a provision for NCS in the allowed revenue, it would be able to recover any overspend through clause 6.76 but would not only retain any underspend but potentially be rewarded through the provisions of the GSM.

In the Draft Decision the Authority noted these comments and removed any provision for NCS from the allowed AA3 revenue cap. Western Power has not accepted this amendment although it has acknowledged the asymmetry of the regulatory framework[70]. It argued that the Access Arrangement does not allow it to recover NCS costs through clause 6.76 of the Access Code. Therefore, if no provision was made for NCS in the revenue cap it would need to undertake capex projects instead and this could potentially be uneconomic. In respect of the regulatory asymmetry, it has proposed that network control costs be excluded from the calculation of the GSM.

Notwithstanding the assumption in our Technical Report, whether or not Western Power can recover NCS over and above the revenue cap as a consequence of a clause 6.76 determination by the Authority is a legal matter and therefore outside the scope of this report. However, we agree with Western Power that NCS is a cost effective way of deferring grid augmentations, particularly on fringe areas of the network, where loads tend to be relatively low and the cost of network augmentation very high because of the distances involved. A regulatory framework that favoured grid augmentation over NCS could therefore result in perverse outcomes.

69 Technical Report, Section 10.7.1, pp130-131.
70 Amended AAI, Section 6.3.4.2, pp68-71.

In its Amended AAI Western Power has used the same NCS opex forecast as the Original AAI without adjusting it to reflect the lower peak demand and energy sales in the 2011 APR. We consider that a downward adjustment would be appropriate as lower energy sales would reduce the running time of NCS generation, resulting in lower fuel and maintenance costs.

We have not included this adjustment in our opex model discussed in Section 3.8.

3.5.3 Transmission Line Removal

In our Technical Report we suggested that Western Power's estimated AA3 opex for transmission line removal be reduced from $6.6 million to $2.38 million based on our estimate of the efficient cost, which we determined by benchmarking Western Power's scope of work against the forecast cost of removing the 132 kV "cricket wicket" line between Pinjar and Eneabba as part of the Mid West Energy Project (MWEP)[71].

In response Western Power's Amended AAI stated:

> *Western Power does not consider this benchmarking to be reasonable, as the Mid West Energy Project line decommissioning is not a relevant benchmark for projects that are generally undertaken because:*
>
> - *the line construct is different*
> - *it is a major project and benefits from synergies with other capital expenditure*
> - *the vegetation costs are much lower due to the sparse and low vegetation types*
> - *environmental mitigation components are excluded*
>
> *Western Power considers its original unit cost estimates proposed in the September 2011 submission are appropriate for estimating an average decommissioning project[72].*

We agree with Western Power to the extent that, if the MWEP project is used as a benchmark for estimating its required expenditure for transmission line removal, an adjustment is appropriate to allow for the factors it notes above. As we stated in our Technical Report:

> *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[73].*

The issue is the magnitude of the adjustment – should it be 20% as we suggested or should it be almost ten times that amount as proposed by Western Power. As noted in our Technical Report, we asked Western Power to provide a breakdown of its original estimate and considered the provisions that it made for risk in this estimate were excessive. We remain of the view that benchmarking the cost against the estimate for the MWEP project is a reasonable approach and that Western Power's original estimate cannot be considered efficient.

In its Amended AAI Western Power appears to have changed its position on the need for this expenditure completely from the Original AAI. It stated:

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71 Technical Report, Section 10.7.2, pp 131-132.
72 Amended AAI, Section 6.3.4.3, p71.
73 Technical Report, Section 10.7.2, p132.

However, consideration of new information, including the 2011 peak demand forecast, has led Western Power to update its transmission line decommissioning and removal program. Western Power will now remove 179 structures on 4 transmission lines and 21 poles at substations at a cost of $2.9 million. This cost estimate has been calculated based on the costs of a recent, average project - the Cannington-Marriot Road decommissioning[74].

We have difficulty reconciling this new approach with the justification that Western Power provided for this expenditure in the Original AAI. In this document Western Power stated:

We will incur costs in AA3 to remove redundant transmission assets to improve public safety. Removing lines and poles that are no longer in service minimises maintenance requirements and public safety risks. This program supports compliance with Part 4 System Safety of the Electrical (Supply Standards and System Safety) Regulations 2001 - Part 4 System Safety[75].

We note that in the MWEP the cost of removal redundant assets is to be capitalised as part of the project. This opex for this line item relates to the removal of existing lines that are no longer used and appears to have nothing to do with the revised 2011 demand forecast. Furthermore the safety issues identified in the original AAI must surely remain and cannot simply be ignored.

We see no basis for amending the proposed provision in our Technical Report for transmission line removal.

3.5.4 Type 1 Obligations

In its Amended AAI[76] Western Power has proposed new opex of $29 million during AA3 to improve compliance with its Type 1 obligations under the *Code of Conduct for the Supply of Electricity to Small Use Customers* (Customer Code). These obligations relate, amongst other things, to the times during which a customer may be disconnected for non-payment of an electricity account, the non-disconnection of customers that rely on electricity for life support and the provision of notice of planned outages to affected life support customers.

Western Power's amended AAI states:

Since September 2011, a number of breaches of Western Power's 'type 1 obligations' have occurred. This has highlighted a number of improvements in current processes and systems that must be achieved in order to prevent further breaches from occurring. There are currently nearly 3,800 customers registered with life support equipment in the Western Power Network[77].

Western Power will use these funds to:

- establish a dedicated team to improve the management of life support equipment customer data and outage notifications. This will include a field visit process to validate the installation of new life saving equipment and will also ensure that these customers are notified in person of planned outages.

- address the planned outage and disconnection requirements through the creation of a dedicated team of seven people to independently review and have control over all distribution access requests. Western Power will also introduce real time system access for Western Power's switching operators to identify any new lifesaving equipment customers that may have been added to the register.

- introduce real-time 24x7 central management to allow for improved monitoring and reporting in the low voltage network. This will include the creation of three

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74 Amended AAI, Section 6.3.4.3, p71.
75 Original AAI, Section 7.4.3, p149.
76 Amended AAI, Section 7.4.4, p71-72.
77 Amended AAI, Section 7.4.4, p72.

day control desks and one night control desk requiring 14 controllers and three system support personnel.

This program of work is treated as a non-recurrent program for the AA3 period. Once the introduction of the new management arrangements are in place and become business as usual, it is expected that the costs associated with this program of work will become stable and will be captured as a recurrent network cost in subsequent access arrangement periods.

Since June 2011, the Authority has published four notices outlining a total of six contraventions of Western Power's Type 1 obligations under the Customer Code. These are summarised as follows:

- The first notice, published on 22 June 2011 identified that Western Power had made 197 non payment customer disconnections out of the prescribed hours and that a total of 309 life support customers had their supply addresses incorrectly recorded;

- The second notice, published on 23 September 2011 related to the disconnection out of hours of a smart grid customer for non-payment. This issue appeared to be related specifically to the management of smart grid customers where, presumably, disconnection was undertaken remotely by Western Power rather than through the normal process requiring a site visit;

- The third notice, published on 23 November 2011 related to a life support customer not receiving notice of a planned outage because the notice was sent to its postal address rather than its supply address, and "the postal address and contact number of the customer were out of date on Western Power's database and consequently the customer did not receive the notification". The notice doesn't state why the data records were out of date so it is unclear whether the problem was that the customer hadn't advised Western Power of the updated details or that Western Power hadn't updated its records.

  This same notice also records that between February and November 2011, a total of 66 life support customers had notice of a planned supply outage sent to their postal address rather than their supply address.

- The most recent notice, published on 21 February 2012, also related to a life support customer not receiving notice of a planned outage. In this case the contractor tried unsuccessfully to contract the customer by telephone prior to the outage, using the correct number, but then went ahead with the outage without personally visiting the address. As a result of this non-compliance, the contractor concerned undertook its own investigation and subsequently dismissed the employee responsible. The Authority also wrote to Western Power requiring it to detail the measures that it will be taking to address the Authority's concerns about Western Power's continuing non compliance with its Type 1 obligations.

The first notice appears to indicate poor record keeping by Western Power (an issue that we have identified and commented on elsewhere in this report) and a somewhat cavalier attitude to compliance with its Type 1 obligations. Notwithstanding the Authority's letter to Western Power prior to issuing the fourth notice, the successive notices actually indicate a progressive and significant improvement in performance to the extent that we believe that the Authority's concerns now appear to have been addressed. The cavalier attitude is gone and the fourth notice related to a single incident where the contractor did make a number of attempts to comply. While the decision to proceed with this outage without visiting the customer was a violation of procedure, the contractor's response in dismissing the employee responsible fully reflected the seriousness with which the incident was treated.

In spite of this significant improvement in performance, Western Power is now proposing a further response that involves the employment of twenty-one additional staff and is going to cost an additional $29 million over AA3. While not wanting to appear dismissive of the value of human life, this is substantial expenditure. We are not convinced that it is necessary to prevent a reoccurrence of a problem that, arguably, appears to have been largely addressed. The dismissal of a staff member by the contractor in response to the latest non-compliance should have been a salutary lesson, to both Western Power and contractor staff, on the need for scrupulous compliance with Western Power's Type 1 obligations.

We have the following further comments:

- Western Power is planning to visit new customers to validate the installation of new life support equipment. We are unsure why this is considered necessary, since we would have thought that medical professionals would have been better qualified than Western Power's own staff to certify the need for this equipment and confirm that it is correctly installed and operating.

- What could be useful, but which does not seem to be planned, would be annual or biannual follow up visits or phone calls to confirm that the service was still required. This would demonstrate to affected customers that Western Power cares and also purge Western Power's records of obsolete data. We suspect that many of the 3,800 customers currently recorded as using life support equipment no longer need the service. Regular personal interaction of this nature may also result in customers being more understanding when an error is made and a procedure is not scrupulously followed.

- The reason a night control desk is needed is unclear as planned outages and disconnections for non-payment do not occur at night. Loss of supply to life support customers as a result of unplanned outages is unavoidable and this is recognised by the Customer Code (notwithstanding the explicit requirement for Western Power to maintain a priority restoration register). The proposed response also appears inconsistent with Western Power's practice of making the network safe when an unplanned outage that occurs in the late afternoon or at night and deferring the fault repair until first light the next morning.

- In our view, the Type 1 compliance notices issued by the Authority reflect a need for Western Power's corporate culture to be more customer-centric. Many would argue that, for this to be achieved, responsibility for front line customer interaction needs to be decentralised and moved closer to the customer. While not taking a position on this point, we note that Western Power's planned response is in direct contrast to this approach, in that it centralises the responsibility in head office, further away from the customer.

3.5.5 Streetlight Switch Wire Program

Western Power has increased its forecast expenditure to accelerate the streetlight switch wire program to address the safety risk associated with these assets. This risk was highlighted by a fatal incident that occurred in 2011[78].

Western Power has also determined that labour costs associated with the decommissioning and removal of switch wires and control boxes under the program should categorised as operational expenditure. The labour and material costs associated with installation of new LV mains and PE cells will continue to be categorised as capex. While Western Power has given no reason for changing its treatment at this point, it states that the changed treatment is consistent with Australian Accounting Standards.

The change in accounting treatment has increased opex by $12.9 million. It appears to be simply a technical adjustment and we see no reason why it should not be agreed.

This adjustment is shown in Table 3.3

[78] Amended AAI, Section 6.3.4.5, pp72-73.

Table 3.3: Additional Opex for Streetlight Switch Wire Program ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Streetlight Switch Wire Program[1]	6.5	6.4				12.9

Note 1: Excludes real cost escalation. As advised by Western Power in response to Question GB72.

3.5.6 Clean Energy Future Package.

In its Amended AAI[79], Western Power noted that the increase in fuel costs associated with the introduction of the Clean Energy Future package will increase its NCS expenditure by $0.21 million over the AA3 period. This seems reasonable. However, we have not modelled these costs since in total they are not material to the overall forecast[80].

NCS opex is discussed in Section 3.5.2 above.

3.6 CORPORATE OPERATING EXPENDITURE

3.6.1 People and Culture Plan

In its Amended AAI[81], Western Power discusses a new two-year People and Culture Plan, which will incur an additional $2.1 million in opex during AA3. Western Power has advised that this new plan is required to embed the cultural change being driven by the 'High Performance Development Team Program" which is being led by Western Power's executive team in response to Recommendation 3 of the Parliamentary Standing Committee's report into Western Power's wood pole management program.

As the People and Culture Plan has been formally accepted by Government in its response to the Parliamentary Inquiry Report, we will not comment directly on its merits. However there are two issues that we would like to comment on, as they relate to the Terms of Reference of our Review.

Before we became aware that the Government had formally responded to the Standing Committee's Report, we asked Western Power to comment further on the need for this program, given that disaggregation had occurred in 2006 and that after disaggregation Western Power had established an Enterprise Solutions Partner with the mandate to drive change through the business. This Partner division is still in place.

Western Power responded:

> *The Enterprise Solution Partners (ESP) Division is not responsible for implementing corporate cultural change. The ESP division was created a year after disaggregation to identify and deliver improvements to business processes and systems. Its key focus areas were, and in some cases remain, Strategic Program of Works (which drives improvements to business processes and enterprise wide IT systems), Operational Excellence, (which focuses on process improvements such as network planning procedures) and Vista (which is the facilities refurbishment project). ESP is not charged with implementing cultural change through employee engagement specifically[82].*

We find this response extraordinary as it implies that it is possible to separate the implementation of corporate cultural change from the implementation of significant changes to corporate procedures and processes. We do not accept this. In our view, the procedures and processes within any organisation must reflect the organisation's culture and values and you cannot have successful process change without accompanying culture change. The indication that Western Power's management, and possibly even its

79 Amended AAI, Section 6.3.4.5, p73.

80 Western Power's response to Question GB72 showed these costs as being an order of magnitude lower than indicated in the Amended AAI.

81 Amended AAI, Section 6.4.1.1, p75.

82 Response to Question GB65, Western Power ref DMS# 9492615, July 2012, p4.

Board, may think otherwise could be a factor in the reports of non-compliance with Western Power's procedures that still come to the Authority's attention.

Our second point is that in a competitive environment, where the price for any goods or services provided is set by the market, the cost of corporate change must be borne by shareholders. This ability to pass these costs through to customers only exists in monopoly situations. The fact that, in seeking to pass the cost of this change program through to its customers, Western Power are exhibiting the very monopolistic behaviour that the program itself should be trying to overcome is an irony that will not be lost on a number of stakeholders. We think this is a cost that the shareholder should carry.

3.6.2 Public Awareness Campaign

Western Power proposes to undertake a public awareness campaign to increase the community's understanding of the potential dangers of Western Power's assets[83]. The program's aim is to ensure the community has the information it needs to stay safe around Western Power's assets. The $3.4 million initiative will include a two-year public campaign outlining safe behaviours and actions when coming across or being exposed to assets, as well as being proactive about reporting incidents or conditions that may give rise to public safety incidents.

Maintaining public awareness of the dangers of electricity transmission and distribution assets should be an ongoing opex activity, which is provided for in Western Power's recurrent opex forecast. That said, we are not suggesting that, given the condition of Western Power's assets and the recent public safety issues that have arisen in respect of these assets, there is not merit in a one-off intensive campaign targeted at further increasing public awareness of the issue.

Such expenditure is highly discretionary and will have little or no direct impact on Western Power's key performance outcomes. If the expenditure is provided for in the revenue cap, there is a risk that the program is not implemented and that the unspent opex is captured as an efficiency gain for which benefits under the GSM are claimed. We are not suggesting that this is Western Power's intention. Nevertheless, if the Authority is minded to allow this opex, it may be prudent to do so with the proviso that the funding is only to be used for its stated purpose and, if not so used, than to advise Western Power that the expenditure would be clawed back during the AA4 review. We caution that we have not investigated whether the Authority is legally able to do this.

3.6.3 Future Energy Alliance

In December 2010, Western Power was directed by the Minister for Energy to establish the Future Energy Alliance, in partnership with Synergy. A key initiative of the Alliance is its marketing campaign, which is designed to change consumer behaviour to become more energy efficient and reduce growth in peak demand. The continuity of the Alliance is considered by June each year. Forecast expenditure for the Alliance was not included in Western Power's September 2011 submission due to uncertainty of whether the Alliance would continue during the AA3 period.

Western Power has not been advised that the Future Energy Alliance will cease in 2012-13. It therefore incorporated forecast expenditure of $6 million dollars into its Amended AAI expenditure submission, to cover proposed Alliance campaigns and initiatives during the AA3 period[84].

We asked Western Power to provide us with a statement confirming that opex associated with the Future Energy Alliance was not included in the base year opex used in its scale escalation model. Western Power responded:

83 Amended AAI, Section 6.4.1.2, p75.
84 Amended AAI, Section 6.4.1.3, pp75-76.

At the time of forecasting, the FEA obligations were understood to be surplus to AA2 expenditure and therefore additional expenditure over AA3 was regarded as appropriate.

However in responding to this request, Western Power has taken the opportunity to review the 2011/12 actual expenditure for the Corporate Communications Branch, which manages the FEA. This analysis indicates that the branch has met its FEA obligations while remaining in budget. This was achieved by the re-prioritisation of some activities, which have, on review, been determined not to be essential during AA3.

Western Power therefore considers that it will be able to meet its FEA obligations from the base Corporate Communications expenditure as detailed in the AA3 submission. Western Power will not proceed with the additional request for FEA funding during AA3[85]*.*

3.6.4 System Management Cost Sharing

Western Power has revised the corporate costs associated with providing services to System Management (Markets). It has estimated that these costs are $4.6 million and has reduced its business support opex for AA3 by this amount[86]. We have not reviewed this reduction or explicitly provided for it in the opex modelling described in Section 3.8.

We also asked Western Power to quantify the value of the technical support it provides to System Management (Markets) and advise how the costs of this support are recovered. It responded:

Technical support such as power system load flow and dynamic studies are paid for by Western Power and covered by the target revenue. No costs for these support services are allocated to System Management (Markets).

As owner and operator of the network, Western Power conducts power system load flow and dynamic studies in order to ensure the secure and safe operation of the network. The Technical Rules (for example Technical Rules 2.3.7.1) require that Western Power shares information with System Management (Markets) to ensure power system stability.

Historically, Western Power has not charged System Management (Markets) for provision of this information. This is because it is difficult to quantify the value of these studies to System Management (Markets). It is also likely that the amount attributable to System Management (Markets) would not be material.

Further, there are no specific items of technical support that are requested by System Management (Markets) and that provide value to System Management (Markets) only.

Therefore, for simplicity, the costs of conducting such studies are included entirely in the AA3 operating expenditure[87]*.*

The IMO is responsible under Section 3 of the Market Rules for operating the power system in a secure and reliable manner and by and large delegates this responsibility to System Management (Markets). In order to carry out these responsibilities System Management (Markets) needs technical support, which is provided by Western Power. This support primarily involves modelling the power flows and dynamic behaviour of the network so that, where necessary, generation is dispatched out of merit in order to ensure that the specified operating security margins are maintained.

The point being made by Western Power is that very little of this modelling is done solely for the IMO since it is generally also required so that Western Power can undertake the network planning functions set out in the Technical Rules. We further note that the requirement to operate the power system in accordance with the security and reliability

[85] Response to Question GB66, Western Power ref DMS# 9492695, July 2012, p2.
[86] Amended AAI, Section 6.4.1.4, p76.
[87] Response to Question GB71, Western Power ref DMS# 9548517, July 2012, p2.

requirements in the Market Rules is, in effect, a constraint on the operation of the market that is primarily for the benefit of consumers rather than generator market participants.

We have not researched the provision of technical support to the Australian Electricity Market Operator or in the New Zealand electricity market. However, from a high level perspective and given that the main beneficiaries of this support are consumers who in turn provide Western Power's regulated revenue (either directly or indirectly), the current arrangement does not appear economically inefficient.

3.7 INDIRECT COSTS

In our Technical Report, we recommended a reduction of 13.69% in indirect costs because our analysis indicated a step increase of 17.3% between the actual indirect costs incurred in the 2010-11 base year and Western Power's forecast indirect costs in 2012-13, the first year of AA3. We considered this step change excessive, given that indirect costs are largely fixed and Western Power has provided no explanation for the increase. We proposed that the reduction be applied to Western Power's indirect cost allocation to both opex[88] and capex[89].

Western Power does not accept the reduction. However, Western Power has revised its forecast to address some of our concerns. In its Amended AAI forecast it has:

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

As shown in Table 3.4, the amended forecast lies between Western Power's original forecast of indirect costs and those shown in our Technical Report.

Table 3.4: Actual and Forecast Indirect Costs ($ million real, 2011-12)

	AA2			AA3					
	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Actual or expected	165.5	150.0	180.0						
Original AAI				190.3	190.2	195.9	201.8	199.1	977.4
Technical Report				164.7	164.6	169.4	174.6	172.4	845.6
Amended AAI				176.9	176.5	175.9	176.2	176.2	881.7

We asked Western Power to provide an analysis showing more explicitly how it derived the forecast AA3 indirect costs in the Amended AAI and how these costs were allocated. Its response[90] indicated that:

- the base year cost of $180 million was assumed to stay constant in real terms during AA3.
- a small adjustment was made to reflect the impact of the variable cost component of the indirect cost forecast. This adjustment was very small and amounted to only $791,000 in 2016-17; and
- a further downward adjustment was made for SPOW efficiencies. This was more significant and totalled $21.2 million over AA3 or an average $4.2 million a year.

88 Technical Report, Section 10.9, pp135-137.
89 Technical Report, Section 9.4, p111.
90 Response to question GB73.

Our main concern with this approach was the use of 2011-12 as the base year. This is not only inconsistent with the base year used in Western Power's scale escalation opex model, but also appears "convenient" in that, as shown in Table 3.4, this expenditure is $30 million or 20% higher than the scale escalation base year cost.

We asked Western Power to explain the volatility in base year costs over AA2. It indicated that[91]:

- The decrease between 2009-10 and 2010-11 was driven by he global financial crisis, which resulted in a significant reduction in the works program and a significant number of redundancies across areas booked as indirect costs;

- In 2011-12 Western Power increased the works program, which led to a significant increase in indirect costs. This included $12.7 million due to an increase in employee numbers and additional costs associated with audits, contract management and strategic reviews. Furthermore Western Power's indirect costs increased by $9.5 million to increase IT support associated with SPOW.

- In 2011-12 there was an accounting change where $8.4 million was transferred from business support opex to indirect costs.

We have a number of concerns with this explanation;

- In developing its AA3 indirect cost forecast Western Power explicitly stated that:

  Indirect costs are largely fixed.

  However Western Power's explanation for the volatility experienced over AA2 directly contradicts this and strongly suggests that indirect cost are very volatile with capex being a major driver of this volatility.

- The F1 expected capex provided by Western Power shows SPOW expenditure, including allocated indirect costs, increased from $26.7 million in 2010-11 to $32.0 million in 2011-12, an increase of only $5.3 million. We discuss Western Power's management of its SPOW program during AA2 in Sections 5.1 and 5.2 of this report. The revelation that an increase of $9.5 million in indirect costs is directly attributable to the SPOW program indicates that the concerns expressed in these sections may well be understated in that they do not account for additional costs that appear to have been "buried".

- Western Power's F1 opex spreadsheet shows business support opex increasing from $63.6 million in 2009-10 to $72.8 million in 2010-11 and then holding steady at $72.8 million in 2011-12. If the costs removed as a result of the accounting adjustment were reinstated, the 2011-12 opex would be $80.2 million. Hence business support expenditure would have increased by $16.6 million or 26% in just two years. We have seen no justification for such a substantial increase.

We conclude that if the 2011-12 indirect costs are to be used as a base year for indirect cost forecasting, they should first be reviewed for efficiency. The indirect costs proposed in our Technical Report were based on the actual 2010-11 costs, the opex component of which was examined for efficiency in our initial review[92]. We understand that the actual 2010-11 costs were also subject to a regulatory audit as part of this review.

The indirect costs used for our Technical Report, shown in Table 3.4 are in total only 4% lower than the Western Power Amended AAI forecast, even though the Western Power 2011-12 base year indirect cost was 20% higher that the equivalent in the 2010-11 base year we used. This is because our analysis made a greater provision for variable cost escalation than Western Power's AAI forecast and did not provide for SPOW efficiency

[91] Response to Question GB69.
[92] Technical Report, Section 10.3, pp114-121.

gains. We see no reason why our Technical Report indirect cost forecast should be adjusted upward and note that the issue of capturing SPOW efficiency gains is discussed further in Section 3.9.1 below.

3.8 SUMMARY OF OPERATING EXPENDITURE ADJUSTMENTS

In this section we consider the overall impact of the adjustments to the opex proposed in our Technical Report and discussed in this Chapter 3 on Western Power's overall AA3 opex requirement. To do this we used the same model that we used for our Technical Report but modified the inputs to reflect the adjustments that we have accepted as reasonable. Our analysis does not explicitly include SPOW efficiency gains, which are discussed and provided for separately in Section 3.9 below.

Based on the application of our model, our proposed opex for AA3 is shown in Tables 3.5 and 3.6. Potential efficiency gains discussed in Section 3.9 are not shown in the tables.

Table 3.5: Proposed Revised 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	7.57	7.82	7.98	8.14	8.31	39.82
New One-off Opex	8.69	8.69	8.69	-	-	26.06
Zero Based Line Items	140.06	134.76	133.25	141.42	150.07	699.57
Indirect Costs	44.30	41.88	41.03	39.41	44.83	211.44
TOTAL OPEX	**459.59**	**457.07**	**459.91**	**463.08**	**482.56**	**2,322.21**
Technical Report Proposal	445.53	441.02	452.05	455.07	474.40	2,268.07
Adjustment to Technical Report Proposal	14.06	16.06	7.86	8.01	8.16	54.14
	3.2%	3.6%	1.7%	1.8%	1.7%	2.4%
Additional Adjustment for Removal of Network Control Services						
Distribution NCS	2.30	2.31	2.34	2.35	2.41	11.71
Transmission NCS	10.76	4.51	9.44	12.08	17.68	54.47
ADJUSTED TOTAL OPEX	**446.53**	**450.25**	**448.13**	**448.65**	**462.47**	**2,256.03**

Table 3.6: Proposed Revised 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	31.05	31.43	31.85	32.33	33.37	160.03
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	44.31	44.89	45.51	46.21	47.74	228.66
Non Recurring Opex	12.73	13.64	7.15	7.08	7.29	47.90
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	**279.94**	**282.98**	**280.70**	**275.97**	**285.52**	**1,405.11**
Transmission						
Network Operations	8.91	8.97	9.03	9.08	9.14	45.13
SCADA and Communications	12.09	12.23	12.38	12.56	12.97	62.23
Maintenance – Corrective Deferred	10.04	10.21	10.33	10.47	10.82	51.86
Maintenance – Corrective Emergency	1.14	1.14	1.14	1.15	1.21	5.78
Maintenance – Preventative Condition	9.85	9.98	10.11	10.26	10.61	50.81
Maintenance – Preventative Routine	17.35	17.56	17.77	18.02	18.64	89.34
Non Recurring Opex	13.74	6.28	11.02	13.86	20.04	64.94
Subtotal - Transmission	**73.12**	**66.36**	**71.78**	**75.40**	**83.43**	**370.09**
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	**106.53**	**107.73**	**107.44**	**111.70**	**113.61**	**547.01**
TOTAL PROPOSED OPEX	**459.59**	**457.07**	**459.91**	**463.08**	**482.56**	**2,322.21**
Additional Adjustment for Removal of Network Control Services						
Distribution NCS	2.30	2.31	2.34	2.35	2.41	11.71
Transmission NCS	10.76	4.51	9.44	12.08	17.68	54.47
ADJUSTED TOTAL OPEX	**446.53**	**450.25**	**448.13**	**448.65**	**462.47**	**2,256.03**

3.9 OPERATING EXPENDITURE EFFICIENCY GAINS

In our Technical Report we noted that Western Power's original AA3 opex forecast made no provision for capturing any opex efficiency gains during AA3. We noted that efficiency gains should be available as a result of the SPOW program whereby Western Power invested in new business information systems and also that Western Power's own benchmarking indicated a significant deterioration in Western Power's operating efficiency over the AA3 period. We stated that, in our view, an efficiency gain of 2% per year should be readily achievable[93].

In its Amended AAI Western Power accepts that there are some potential opex efficiencies available from SPOW, which it quantifies as $7.2 million in total over the five year AA3 period. Apart from that, it considers that any operating efficiencies available to it were already captured during AA2 and no further efficiencies were available. Alternatively, it considers that our suggested efficiency dividend of 2% per year should not have been accepted by the Authority as it was not supported by reasoned analysis[94]. It included a report by Wedgewood White that analysed past AER regulatory decisions identified only two instances where a cumulative 2% opex efficiency factor had been applied[95]. In only one of these instances had the efficiency target set by the regulator actually been met[96].

In the following sections we examine the evidence that suggests to us that opex efficiency gains should be available to Western Power.

3.9.1 SPOW

The SPOW program has been in place since early AA1 and has the objective of replacing the legacy business information systems, which Western Power's inherited on disaggregation, with proprietary systems designed to facilitate the efficient operation of a modern network service provider. As of February 2009, $25.3 million had been spent on the program. However, given that this expenditure was considered ineffective[97] and given the Authority's decision not to permit all AA1 capex to be included in the capital base, we will ignore SPOW expenditure prior to the commencement of AA2 for the purposes of this section.

Currently the SPOW program is expected to be substantially complete by the end of 2013-14 and over the period 2009-14, actual and forecast expenditure on the program totals $132.3 million. The program includes the following key components:

- *Ellipse:* Mincom Ellipse is Western Power's core business resource planning and has been used by Western Power since 1999. It supports the organisation's core requirements across all streams of the business including asset and works management, materials and logistics, finance, human resources and payroll. Under SPOW, Ellipse has been upgraded to the latest version and additional modules have been added to increase its functionality.

- *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.

- *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.

93 Technical Report, Section 10.11, pp138-139.
94 Amended AAI Section 6.6, pp78-88.
95 *Review of Operating Expenditure Efficiency Adjustment,* Wedgewood White Ltd, 23 May 2012. This report was included as Appendix J to the Amended AAI.
96 TransGrid 2004. See Section 2.5, p8 of the Wedgewood White report.
97 *Report on Expenditure Governance, Western Power,* Geoff Brown & Associates Ltd, 14 July 2009, pp43-45.

- *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.

Western Power provided a copy of a Statement of Program Intent dated 30 June 2009, which provided a high level justification for the SPOW program[98]. While the purpose of this document is not entirely clear, we assume this was the basis on which the Western Power Board authorised the program to proceed. The document contained a very high level summary of the expected benefits of SPOW, which are shown in Table 3.7 below.

Table 3.7: Cost Benefit Analysis of SPOW Program ($ million real, 2008-09, per annum).

Benefits directly arising from SPOW solutions	
Reduction in IT infrastructure costs	$3-5 million
Reduction in IT application support costs	$2-4 million
Reduction in administration support costs	$1-2 million
Reduction in data services support costs	$1-2 million
Total Direct benefits	**$7-13 million**
Indirect Benefits[1]	
Increase in productive business hours	$15-30 million
Reduce unit costs of products or services	$42-85 million
Improve the use of capital (through doing the right projects)	$45-90 million
Total Indirect Benefits	**$103-205 million**
TOTAL BENEFITS	**$110-218 million**

Note 1: Indirect benefits are defined in the analysis as *[benefits that] rely on the business making other decisions leveraging the SPOW solution.*

We asked Western Power to quantify the SPOW benefits that it had included in its AA3 expenditure forecast. Key elements of its response were[99]:

- A total of $135.6 million of SPOW efficiencies have been identified through to the end of AA3. Of this, $59.6 million efficiency benefits were captured in AA2 and a total of $76 million of benefits are expected in AA3. Of this latter amount, $38.6 million was included in the original AAI and a further $37 million has been included in the Amended AAI.

- The expenditure forecast for 2016-17, the final year of AA3, provides for total SPOW efficiencies of $17.49 million, including efficiencies in both the Original and Amended AAI. This includes $10.87 million capex, $4.87 million indirect costs and only $1.99 million opex.

We are sceptical about the $59.6 million SPOW efficiency gains that Western Power claims to have already captured in its AA2 actual costs. AA2 was an intense period of system implementation that, as discussed in Chapter 5, was not without its difficulties. Western Power is suggesting that, on an annual basis, more efficiencies were captured before the information systems were actually implemented than are forecast to be captured following implementation. We consider this unlikely.

[98] *SPOW. Statement of Program Intent.* Western Power, 30 June 2009, (Ref DMS# 6172280).

[99] Response to Question GB75.

Western Power also considers that the bulk of its efficiency gains will be captured through capex efficiencies, rather than opex. However, all of the business information systems described above are designed to improve the efficiency of the opex effort and we think that the available opex efficiencies are therefore substantially greater than suggested by Western Power in its Amended AAI. It appears that Western Power's primary focus is on improving the efficiency with which it delivers capex outcomes and very little consideration has been given to how the information systems installed under SPOW could be leveraged to improve the efficiency with which it undertakes routine operations funded through opex. This is discussed in Section 2.6 with regard to the preventive routine maintenance effort. Another example of such an area is meter reading where, by the end of AA3, the vast majority of the three phase meters will be read remotely, as a result of the smart grid program. However the Amended AAI uses meter reading as an example of an opex activity where significant efficiencies or economies of scale are not available[100].

In our view, the focus on capex is a significant design issue with the program. Given that the information systems installed under SPOW are designed to facilitate Western Power's routine operations, we think the program's primary objective should be to reduce the opex spend. While the program will undoubtedly provide opportunities to improve capex efficiency, these should be considered indirect benefits rather than the primary focus. In Western Power's situation, given the poor condition of its network and the limited availability of funding, capex benefits likely to be manifest, at least in the short term, in a better targeting of available capex and the ability to do more with the available expenditure. These benefits are difficult to measure directly. Because these are the primary benefits of the program as currently formulated, we think that it will be very difficult to evaluate the program's success.

In our view, Western Power should assess the effectiveness of the program in terms of the opex efficiencies it produces. In this context, we suggest the mid-point of the relevant line items in Table 3.8 that are relevant to opex form an appropriate basis for setting a target for the annual opex efficiency gains to be achieved by 2016-17. These include all direct cost line items as well as the increase in productive business hours. This suggests a target of $32 million as of 2009. We have escalated this by 9.4% to real 2011-12 dollars and then by a further 5.4% to reflect the increase in opex in real terms as shown in Table 3.5. This gives a target annual opex efficiency gain of $36.9 million in 2016-17.

This target would be achieved by applying a 2% compounding efficiency factor to all opex other than NCS, applied from 2013-14. Our analysis shows that this approach yields annual efficiency savings of $35.9 million in 2016-17, which is less than the target suggested above.

An alternative approach would be to apply the 2% efficiency factor to the transmission and distribution opex but not to corporate opex, on the basis that a higher proportion of the corporate opex is not controllable by Western Power. This approach would yield an efficiency gain of $27.1 million by 2016-17. The main advantage of setting a less challenging glide path is that it leaves more headroom for the operation of the GSM, which could potentially provide a strong incentive for Western Power to operate in a more commercial manner to achieve even greater savings.

3.9.2 Benchmarking

Notwithstanding the limitations of comparative benchmarking, it nevertheless is used by the industry, including Western Power in its Original AAI, as a tool for producing a high level sanity check on the results of alternative analyses. In this section we compare the opex efficiency of Western Power with that of the network service providers in two comparator states, both before and after the application of an efficiency factor, in order to get a better understanding of the magnitude of the efficiency gains that are available to Western Power.

100 Amended AAI, Section 3.3.1, p56.

We have used Queensland and South Australia as the comparator states, because these most closely resemble Western Power's service area. Both are large mining states with a single dominant metropolitan area and a large sparsely populated rural area. The South Australian power network is slightly smaller than the SWIN, both in terms of line length and number of customer connections, whereas the Queensland network is approximately twice the size. Hence we consider South Australia the more valid comparison. For this analysis, we used the same data as for the benchmarking study in our Technical Report[101], although we escalated both the South Australian and Queensland opex by 6.1%[102] to provide for real cost escalation through to 2011-12. Hence the assumed opex used in the study is based on actual costs as of 2011-12 and real cost escalation after 2011-12 is not taken into account.

The result of this analysis is shown in Table 3.8:

Table 3.8: Benchmarking Analysis ($, real 2011-12, unless otherwise shown)

	Opex ($ million)	Line Length (km)	No. Customers	Opex/ km Line	Opex/Cust.	Opex/Cust.-km
Queensland	915	212,825	1,978,885	4,302	463	0.00217
South Australia	268	92,811	817,300	2,891	328	0.00354
Western Power[1]	483	103,000[2]	1,162,284[3]	4,685	415	0.00403
Western Power[4]	447	103,000[2]	1,162,284	4,337	384	0.00373
Western Power[5]	455	103,000[2]	1,162,284	4,422	392	0.00364

Note 1: 2016-17 opex (including NCS) with no efficiencies. See Table 3.6 and 3.7.
Note 2: Our estimate taking into account the impact of capex reductions and our concerns regarding the Western Power data as discussed in Section 3.4.1.
Note 3: As projected by the Deloitte report. See Section 3.4.1.
Note 4: 2016-17 opex (including NCS) after application of a compounding 2% efficiency factor to all opex except NCS from 2013-14.
Note 5: 2016-17 opex (excluding NCS) after application of a compounding 2% efficiency factor to transmission and distribution network opex other than NCS from 2013-14.

The analysis in Table 3.8 compares Western Power's projected performance in 2016-17 with the two comparator states, assuming the $483 million opex proposed in this report. We have included NCS in this analysis to provide a more valid comparison[103]. Table 3.8 also demonstrates the effect on the benchmark comparators of applying a 2% efficiency factor to the whole opex budget (excluding NCS)[104] from 2013-14 as discussed in Section 3.9.1 and also of applying the same 2% factor to transmission and distribution opex only and excluding corporate opex. It shows a poorer performance than Western Australia against all three benchmarks for all efficiency scenarios and a poorer performance than Powerlink on the opex per km and the composite benchmark.

3.9.3 Return on Investment Analysis

As noted in Section 3.9.1 the cost of SPOW program, excluding costs incurred prior to the start of AA2, is expected to be $132.3 million. In this section we consider the extent to which opex efficiencies will recover this investment. We accept that there will also be capex efficiencies resulting from the SPOW program but consider these difficult to measure and unlikely to be manifested as reductions in total capex requirements in the short term. However we acknowledge that these benefits are real.

For the investment in SPOW to be economic, the efficiencies must provide a return on invested capital and a return of capital. If an eight year life is assumed, the required return of capital is $16.5 million per year. The required return on capital is governed by the WACC, which during AA2 was 7.98% (real, pre-tax). In the Draft Decision, this was reduced to 4.73%. Hence the required return of capital will be between $6.3 million and $10.6 million. We conclude that, for the SPOW programme to be worthwhile, minimum

101 Technical Report, Section 10.3.1.2, pp115-116.
102 Based on 2% real cost escalation over three years.
103 NCS is referred to as "network support" by the AER. We have reviewed the most recent regulatory proposals from both Powerlink and ElectraNet on the AER web site to confirm that their opex includes the cost of network support.
104 It is not known whether the opex of the two comparators include an NCS component.

opex efficiencies in the range of $23-27 million per year should be realised by the end of AA3.

3.9.4 Conclusions

We consider Western Power's SPOW program to be poorly formulated in that it has the objective of leveraging capex efficiencies through the implementation of systems that are designed primarily to improve the efficiency of routine operations funded through opex. As the targeted capex benefits are indirect and difficult to measure, we do not see how Western Power can evaluate the effectiveness of the program in a meaningful way.

A consequence of this focus on capex is that the effort Western Power is applying to actively developing business processes and procedures that would leverage the capabilities of the new information systems to improve the efficiency of its opex spend is limited. We do not accept the premise in the Amended AAI that all opex efficiencies available to Western Power have already been captured and that no additional efficiencies are available. Our benchmarking analysis against network service providers in similar eastern states also suggests otherwise.

We believe that leveraging the greater capabilities of enhanced information systems to improve the efficiency of the opex effort should be the main focus of the SPOW program. This implies that the capturing of indirect capex benefits should be secondary, although we are not suggesting these be overlooked completely.

Our analysis suggests that by 2016-17, annual opex benefits of more than $23-27 million[105] are needed to justify the investment in SPOW and a benefit of around $37 million is needed to meet Western Power's own target for the program. Our benchmarking suggests that benefits of this magnitude are realistic.

Benefits of this magnitude cannot be achieved instantaneously as they require changes to business systems and operating procedures that take time to implement. They are also unlikely to be achieved without a culture change within the organisation and this will also take time. For this reason the achievement of the required efficiencies should be reached by means of a glide path. We suggest that the efficiency factor is not applied until 2013-14 to give Western Power time to develop its strategy for achieving the required savings.

Achievement of annual benefits of $36 million by 2016-17 would require a compounding efficiency factor of 2% to be applied to the full opex proposed in this report. An alternative approach would be to apply the 2% efficiency factor only to non-corporate opex, which would deliver benefits of $27 million by 2016-17. This would provide some head room for the application of the GSM, which could potentially provide a strong incentive for Western Power to deliver even further opex efficiencies.

105 Because of the glide path, benefits prior to 2016-17 will be lower. This creates a shortfall, which should also be recovered.

4. FORECAST CAPITAL EXPENDITURE

4.1 TRANSMISSION CAPACITY EXPANSION

4.1.1 Mid West Energy Project

Western Power included around $35.4 million capex in its original AA3 capex forecast for stage 2 of the MWEP (southern section). In its Draft Decision the Authority misinterpreted this expenditure as relating to the northern section of the MWEP and removed it from the forecast as there is considerable uncertainty regarding when the northern section of the project will proceed[106]. In the amended AAI Western Power clarified that this expenditure related to the southern section of the MWEP and is required to allow both sides of the new double circuit line to operate at 330 kV. Western Power considers that the work is necessary to accommodate forecast generation developments and new block loads in the region[107].

We confirm that the capex needed to allow the second circuit of the MWEP to operate at 330 kV was not included in the original MWEP budget. The additional cost is required to provide an alternative 132 kV supply to Regans and to modify the circuit terminations at other substations to provide for 330 kV operation. However, we are unaware of any new block loads that would require this augmentation, which would be required to allow the connection of the proposed 330 kV Eneabba terminal station, to be commissioned before the end of AA3.

In its original AA3 capex forecast, Western Power included the Eneabba terminal station to provide for the connection of new wind generation at Eneabba. However, in our Technical Report[108] we suggested that the need to connect this new wind generation was still speculative and there was therefore a high probability that the terminal station would not be needed before the end of AA3. We therefore proposed that the Eneabba terminal station not be included in the AA3 capex forecast in order to reduce the risk that customers end up paying in advance for an augmentation that turns out not to be needed. Should wind farm development proceed to the stage where construction of the new terminal station should proceed before the end of AA3, and the project meets NFIT requirements, then Western Power could recover its costs through the IAM.

This logic applies equally to the commissioning of the second MWEP circuit at 330 kV and the $35.4 million expenditure for this project should therefore only be included in the AA3 capex forecast if the Eneabba terminal station is also included.

4.1.2 CBD Development Plan

In its Original AAI, Western Power proposed capex of $108.9 million for the installation of a new transformer at Cook St and the construction of a new zone substation within the Perth CBD. In addition there was a provision of $29.6 million for two new 132 kV cable circuits to supply the new zone substation. While the new zone substation, with a planned 240 MVA of new transformer capacity (compared to a current total load of approximately 400 MVA in the East Perth and CBD load area) was classified as a growth driven project, additional information provided by Western Power indicated that the primary driver for the new substation was the need to replace the existing 11 kV switchboards at Hay and Milligan Street substations for safety reasons. Based on the information provided to us by Western Power we recommended that construction of the new zone substation be deferred until AA4[109]. We were not convinced that installation of so much new transformer capacity was needed at this time and the condition information provided to us by Western Power led us to conclude that the switchboard replacements could be deferred until a longer term strategic plan for the CBD could be prepared. This adjustment reduced the AA3 capex forecast by $125.0 million.

106 Draft Decision, Paragraph 530, p126.
107 Amended AAI, Section 8.2.1.1, p119.
108 Technical Report, Section 7.2.3, p78.
109 Technical Report, Section 7.2.2, p76.

Western Power provided a very comprehensive report by engineering consultants Sinclair Knight Merz (SKM) on the development of the electricity supply to the CBD as a confidential appendix to the Amended AAI. This contained significantly more information on the emerging problems with the existing CBD network than was made available to us in the Original AAI. Key messages in this report were:

- The existing security of supply requirements for the Perth CBD, as set out in clause 2.5.3 of the Technical Rules, were generally consistent with the security requirements for the CBDs of other capital cities in Australia and around the world and are an appropriate basis for planning the development of the CBD electricity supply going forward. We agree.

- Where there are two or more transformers at a zone substation there needs to be three incoming transmission supplies, one of which can be a tie line to a nearby zone substation. This will ensure that in a worst case N-2 scenario there is still an incoming supply available. If there are only two incoming supplies then supply can be lost completely to the substation, sometimes disconnecting three or four transformers. We agree with this and note that Western Power's current practice is to have only two incoming supplies to each substation. As zone substations within the CBD are relatively close together, the installation of tie lines between zone substations appears to be a relatively low cost strategy for meeting the Technical Rules security requirements.

- The 66 kV transmission voltage assets within the CBD are nearing end of life and this voltage should be phased out. We agree with this and note that it is difficult to meet the n-2 security requirements for the CBD with two different transmission voltages. For example, it is not possible to construct a tie line between two zone substations operating at different voltages without also installing a new power transformer. Phasing out the 66 kV voltage level means that the circuits supplying the Wellington Street and Forrest zone substations and the transformers and high voltage switchgear at these substations need to be replaced. SKM recommends these two substations be replaced by a single new substation at Bennett Street and, on the information we have seen, this seems a prudent strategy.

- There is significant congestion of 11 kV cabling both at the exits to zone substations and within the city itself. Western Power's current practice is to direct bury its cables under the footpath, but congestion may require it to move out under the carriageway. However, this could be frustrated by a requirement of the City of Perth that utilities limit the frequency with which they dig up a particular carriageway to no more than once every fifteen years. SKM suggests that migration to a 22 kV distribution system could be a solution and recommends further investigation.

  Practical construction issues need to be considered as part of the overall development strategy as they can be significant constraints and can also have a major impact on costs.

  Cable congestion at zone substations is an issue that should be foreseen in advance and planned for at the design stage. The maximum number of feeders that need to exit a zone substation is determined by the number and size of transformers and is therefore known at the time a new substation is planned. If substation exits are designed to cater for this number of cables, congestion at a later time should not occur.

  Migration to a 22 kV system would reduce the number of feeders required to supply a given load but would create new operational and construction problems that could persist for decades. Having two distribution voltages within the CBD would limit the ability to transfer loads between zone substations and is likely to mean significant asset under-utilisation during the transition period. The costs associated with these transitional problems are real and likely to be substantial. Other solutions, such as the construction of a pit and duct system as new cable circuits are installed and increasing the utilisation of the existing 11 kV distribution network which we discuss below, could be more cost effective. All cities reviewed in the SKM report, which included Australian capital cities, London and Berlin, use 11 kV distribution for their CBD areas and Perth is the only Australian capital city that does not use a pit and duct system for its electricity distribution network.

- Each 11 kV feeder is paired through a normally open switch with a feeder from another zone substation. No feeder is loaded to more than 50% of its thermal cable rating, which means that each feeder pair can be supplied from either of its two zone substations. We think this is a good system as it not only meets the security requirements of clause 2.5.5.2 of the Technical Rules but also allows substations to be offloaded through the distribution system in the event of a contingency without interrupting supply to consumers for extended periods of time. While from a feeder loading perspective it should be possible to fully offload a substation, in practice the amount of load transfer that can occur will be limited by the spare transformer capacity available at other substations. To mitigate this problem, we suggest Western Power ensure that feeders from any given CBD zone substation are paired with feeders from more than one alternative substation.

  The switching time required to complete distribution load transfer means that this distribution transfer capacity cannot be used for managing N-1 transmission contingencies within the CBD as clause 2.5.3 of the Technical Rules allows an interruption time of only 30 seconds before supply is restored. It can however be relied on to deal with an N-2 transmission contingency where a two hour interruption is permitted before all supply is restored.

  Another disadvantage of the existing arrangement is that distribution feeders can only be loaded to 50% of their thermal capacity. SKM suggests that if each feeder was grouped with two others through normally open switches then it would be possible to load feeders up to 66% of capacity since, in the event of a distribution fault, the load on any feeder would be shared by two others. This has some merit. Ideally the three feeders in a group would each be supplied from different substations but this has protection and operational ramifications since it means that, under a contingency situation, two zone substations would be paralleled through the distribution network.

Western Power's current CBD design philosophy, as implemented at the Hay and Milligan Street zone substations, and as we understand it was proposed for the new CBD substation in the Original AAI, is to have only two incoming transmission circuits and N-2 transformer redundancy. We agree that Western Power should review this approach and consider whether one utilising three incoming transformer circuits (including a tie line to a neighbouring substation) and N-1 transformer redundancy would be more cost effective. We understand that this approach is planned for Bennett Street. We further suggest that, with the construction of the tie line between Hay and Milligan Street substations, Western Power review the need to maintain N-2 transformer redundancy at these two substations and whether these transformers can be more fully utilised. This may mean reconfiguring the distribution network so that more feeders from these two substations are paired with feeders from other zone substations.

We also suggest that Western Power review its arrangement for the construction of new 11 kV switchboards within the CBD to minimise the disruption to network operation when a switchboard needs to be replaced. This would also improve the robustness of the network to an 11 kV switchboard fault. A separate switchboard for each transformer, with cable or removable bus ties between adjacent switchboards is one possibility.

In its Amended AAI, Western Power has submitted a revised forecast for transmission capex to support the CBD, based on the development plan outlined in the SKM report. This is shown in Table 4.1. The plan provides for the construction of the new Bennett St substation by 2019 to allow the transfer of load from the 66 kV Wellington Street and Forrest substations before these substations are decommissioned. It should be noted that the forecast in Table 4.1 does not include the additional transformer at Cook St, which was provided for in the Draft Decision.

Table 4.1: Western Power's Forecast CBD Transmission Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Cook Street to Western Terminal 132 kV Overhead Line	-	-	0.1	0.3	2.0	2.4
East Perth to new Bennett Street Substation - Two 132kV cable circuits	-	-	0.5	0.7	4.9	6.1
New Bennett Street Substation	0.4	1.0	10.6	10.3	35.5	57.8
Hay Street to Milligan Street 132 kV cable	0.1	0.4	1.5	5.1	0.6	7.8
Complete Joel Terrace 132 kV Conversion	0.7	4.4	9.9	0.9	-	15.8
James Street - Single Transformer	0.1	0.3	0.9	5.9	13.2	20.4
TOTAL	**1.3**	**6.1**	**23.3**	**23.2**	**56.3**	**110.3**

While the forecast expenditure shown in Table 4.1 is only 11.8% lower than the $125.0 million CBD capacity expansion capex disallowed in the Draft Decision, the projects on which it will be spent are very different. This is because the expenditure now forms part of a longer term strategy to address emerging issues within the CBD and in particular the future of the ageing 66 kV infrastructure and the operating and capacity problems that would eventually arise if these assets were to be replaced on a like for like basis. These were issues that were not raised in the Original AAI. We suggested in our Technical Report that the CBD development plan in the Original AAI was sub-optimal and not well developed[110], and the radically different plan now proposed on the basis of the SKM study confirms this.

We think the development program shown in Table 4.1 is more about asset replacement than about capacity expansion and, with the exception of the Cook St-Western Terminal overhead line, which we discuss in Section 4.1.2.1, we support the program[111]. We note that the new Bennett St substation and the Joel Terrace conversion will allow the removal of all 66 kV assets within the CBD and the East Perth terminal station. The Hay Street – Milligan Street 132 kV cable and the new single transformer substation at James Street will allow better utilisation of the existing transformer capacity at these two substations and also facilitate the replacement of the substation 11 kV switchboards.

4.1.2.1 Cook Street – Western Terminal Overhead Line

The one CBD project that we do not support is the proposed new Cook Street – Western Terminal overhead line. While the estimated cost is relatively low, we discuss this project in some detail as it typifies our concerns regarding Western Power's capacity expansion capex planning and particularly its consideration of asset risk.

Western Power has included this project in its Amended AAI[112] because SKM found that, by the end of AA3, the Western terminal station may not meet the N-1-1 security criterion required by clause 2.5.2.3 of the Technical Rules. This clause requires that substations designed to the N-1-1 criterion must be able to continue to supply up to 80% of their peak demand if an unplanned outage of a transmission element occurs at the same time as there is a planned maintenance outage of another element.

110 Technical Report, Section B2.3, ppB6-B7.

111 This raises the issue whether some of the projects should be categorised as asset replacement rather than capacity expansion. While the primary driver for proceeding at this time with some projects is asset replacement, the new assets will also deliver an increase in capacity. The complexity of large projects with the CBD is such that we consider the risk that Western Power will not deliver to is proposed program to be high. From a regulatory perspective, categorisation as asset replacement would result in a windfall gain to Western Power should there be a delay, as asset replacement projects are not subject to the IAM. This would be a somewhat perverse outcome.

112 It was not included in the Original AAI.

The N-1-1 criterion provides a higher level of security than the N-1 criterion and is intended to reduce the risk of widespread supply interruptions, affecting a large number of customers over a wide area, should a transmission fault occur at the same time as a planned maintenance outage. The 80% peak load threshold is specified as it is not good industry practice to plan maintenance outages for times of peak demand.

One impact of the N-1-1 criterion is that Western Terminal must have at least three incoming 132 kV circuits. Hence, when one line is out of service for planned maintenance and a fault occurs on another incoming line, a third line must be available to supply the station. Western Terminal already has the required three incoming 132 kV circuits. However, SKM's analysis has shown that the forecast load growth at Western Terminal is such that, in a worst case N-1-1 scenario, by the end of AA3 there may be insufficient capacity on the remaining in-service incoming line to supply the full load. In this event load shedding would be necessary. Western Power argues that, in order to avoid a Technical Rules non-compliance, a fourth incoming circuit is therefore needed. Hence it considers that a "do-nothing" approach is not an option. We have seen many Western Power business cases that have been accepted by the Board taking a similar line.

However, the business risk that this project is trying to manage is, in our view, substantially lower than other risks of non-supply within the Western Terminal load area that the network is not designed to mitigate and that Western Power and ourselves both consider acceptable and in accordance with good industry practice.

We suggest that:

- The SKM analysis is based on a POE 10 load forecast and explicitly ignores diversity. The conservative assumptions on which the analysis is based suggest that the project could be deferred for some years, with very little increase in business risk. We are also a little mystified by the SKM analysis, as the smallest incoming 132 kV circuit to Western Terminal has a thermal capacity of 210 MVA, 35% higher than Western Power's POE 10 2013 peak demand forecast for Western Terminal of approximately 155 MVA. There is no suggestion that the Western Terminal peak demand will increase to the extent that this line would be overloaded under an N-1-1 contingency within five years[113].

- It may be possible for Western Power to further defer the need for the project by scheduling planned maintenance for times when the expected actual demand was below 80% of peak. Western Power provided us with a load profile of Western Terminal, which shows that there is a nine month window when the load does not exceed 75% of the annual peak demand. Within this, there is also a three month window where system peak is less than 65% of annual peak demand.

- As there are already three 132 kV lines supplying Western Terminal, the load at risk is limited to the demand over and above the capacity of the existing circuit remaining in service following an N-1-1 contingency. This is a much lower risk than would be the case if there were only two incoming lines, when an N-1-1 contingency would result in a complete loss of supply, the situation that the Technical Rules requirement is primarily intended to prevent. In Western Terminal's case, should an N-1-1 situation arise where load shedding is necessary, the impact on customers could be managed by load rationing, where feeders supplying non-essential services could be disconnected on a rotating basis for short periods of time. As the affected customers cover a wide area it is most unlikely that any customer would need be disconnected more than once.

However, within the Western Terminal load area network, and indeed within the whole of the SWIN, an N-1-1 contingency could well result in the full interruption of one, and sometimes more than one, zone substation, since each zone substation is supplied by

113 Other factors such as voltage stability or loads outside the Western Terminal supply area may determine the maximum power transfer available in a contingency situation. Therefore we are not saying that the SKM analysis is wrong but we would want further clarification before we relied on it.

only two incoming circuits. The impact of such a contingency on customers would be much more severe than a potential Western Terminal incoming circuit overload, because the load lost would be significantly greater and the potential for mitigating the impact through load rationing would usually be limited. In our view the risk to Western Power of such an event is correspondingly greater.

We do not see the logic of proceeding with a capacity expansion project to mitigate a relatively small risk, when much larger risks within the same load area are tolerated as a matter of course and are considered acceptable by industry standards. We conclude that, if the construction of an additional Cook Street-Western Terminal circuit was prioritised on the basis of business risk, it would be deferred until the load at risk was comparable to the typical load on a single zone substation. This would indicate that the project is not required in the medium term. In order to mitigate any legal risk of not proceeding, Western Power should seek a Technical Rules exemption form the Authority and only proceed with the project if this is not granted.

4.1.3 Eneabba Terminal Station

Western Power's Original AAI proposed the inclusion of $17 million in the AA3 capex forecast for the construction of a new terminal station at Eneabba to allow the connection of new wind generation to the grid. As discussed in Section 4.1.1 above, we considered this speculative and considered that it should not be included.

In its Amended AAI, Western Power stated that it believes this generation will materialise during AA3. However, it now considers that the costs are adequately provided for in the customer driven capex category[114].

4.1.4 Environmental and Planning Costs

In its Original AAI Western Power proposed an average provision of $11.3 million per year capacity expansion capex for "environmental and planning" costs. This was for costs incurred in the planning of capex projects before a project passed Gate 1 of the seven gate project development and implementation process. We suggested that this expenditure not be allowed because expenditure cannot be capitalised unless it passes NFIT. This requires a customer benefit to be established and there is no customer benefit if an asset will not exist in a physical form. We also raised the issue of how such an asset would be depreciated[115].

In its Draft Decision the Authority did not allow this expenditure and did not include it as opex, even though we indicated in our report that it was a valid cost. In its Amended AAI, Western Power has treated environment and planning costs as well as strategic planning costs that cannot be attributed to a specific project as indirect costs and allocated them across opex and capex as with other indirect costs[116]. In our view this treatment is appropriate.

Nevertheless there is still, in our view an issue in respect of cost capitalisation that has not been resolved. This arises from the different treatment of cost capitalisation in the financial and regulatory accounts and relates to the treatment of the cost of projects that pass Gate 1 of the project development program but do not proceed to commissioning. In the financial accounts assets are not capitalised until they are commissioned, and if a project is not commissioned any expenditure incurred is treated as opex and, in effect, written off. In the regulatory accounts, expenditure on new assets is capitalised as incurred and Western Power is of the view that, should a project not proceed or be deferred, costs should still be capitalised. This should not be an issue in respect of costs incurred during the regulatory period in which the project was cancelled or deferred, if these costs are captured by the ex-post NFIT test and not included in the opening RAB for the next regulatory period. However if a project is cancelled after prior period costs have been included in the RAB there does not appear to be any mechanism by which these costs are reversed out. We think there would be benefit in the Authority clarifying

[114] Amended AAI, Section 8.2.1.1, p120.
[115] Technical Report, Section 7.2.5, pp79-80.
[116] Amended AAI, Section 8.2.1.1, p120.

the treatment in the regulatory accounts of costs incurred on projects that do not proceed to commissioning within a reasonable time.

4.1.5 Impact of Reduced Load Growth

In our Technical Report we proposed a reduction in capacity expansion capex to provide for the reduced demand forecast in the 2011 APR. This has already been discussed at a philosophical level in Sections 2.4 and 2.5 of our report. In summary, we do not accept Western Power's hypothesis that it is the *rate of demand growth* and rather than the *actual demand* that should determine Western Power's capacity expansion capex requirements. We also presented an alternative analysis using different input assumptions that suggested that the demand growth that AA3 capacity expansion capex needed to provide for was significantly lower than assumed in our Technical Report. We concluded that, although the reductions in our Technical Report were high level and based on very broad assumptions, they were not excessive and provided Western Power with some scope to address the issue of customer risk.

In the following subsections we address specific points raised by Western Power in its Amended AAI.

4.1.5.1 Zone Substations

In its Amended AAI Western Power has submitted that our proposed provision for new zone substations and additional zone substation transformers was not sufficient to allow Western Power to provide address a backlog where zone substation capacity does not meet the N-1 or 1% NCR criteria set out in the Technical Rules and also to cater for new demand growth[117]. Table 43 of the Amended AAI identifies six projects where either new zone substations or additional transformer capacity at existing zone substations to address existing Technical Rules non compliances without allowing for any new demand growth.

The provision in our Technical Report for new zone substation transformer capacity outside the Perth CBD is analysed in Table 4.2.

Table 4.2: Forecast AA3 Capex for Zone Substation Capacity ($ million real 2011-12, excluding real cost escalation)

	Total AA3	Technical Report Reference
Western Power Forecast	362.5	Table 7.2
Less		
CBD substation	95.4	Table 7.3
Cook St CBD transformer	13.5	As forecast by Western Power
Forecast zone substation augmentation capex outside CBD	253.6	
40% reduction for reduced load growth	101.5	
Remaining zone substation provision	**152.2**	

The total load growth reduction of $101.5 million calculated in Table 4.2 above is less than the reduction of $106.9 million shown in Table 7.6 of our Technical Report. The difference arises because the analysis in the Technical Report removed only the CBD substation from the Western Power forecast and did not remove the Cook St transformer before applying the reduction. There is a good case for also removing the Cook St transformer as it is appropriate to treat the transmission supply issues within the CBD separately from the rest of the network. We therefore suggest the Authority increase the provision for transmission supply capex by $5.4 million in its final decision. The breakdown of this proposed adjustment is shown in Table 4.3.

117 Amended AAI, Section 8.2.1.1, pp122-123.

Table 4.3: Proposed Increase in AA3 Transmission Supply Capex ($ million real 2011-12, excluding real cost escalation).

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Western Power forecast transmission supply capex[1]	**20.6**	**75.8**	**102.8**	**109.4**	**54.0**	**362.5**
Less						
CBD substation[1]	-	3.9	26.8	59.9	4.8	95.4
Cook Street transformer[2]	2.3	10.1	1.1	-	-	13.5
Supply outside CBD	**18.3**	**61.8**	**74.9**	**49.5**	**49.2**	**253.7**
Proposed reduced load adjustment (40% of supply outside CBD)	(7.3)	(24.7)	(29.9)	(19.8)	(19.7)	(101.5)
Adjusted transmission supply capex outside CBD	**11.0**	**37.1**	**45.0**	**29.7**	**29.5**	**152.2**
Technical Report reduced load adjustment[3]	(8.2)	(28.8)	(30.4)	(19.8)	(19.7)	(106.9)
Adjustment to Technical Report transmission supply capex	**0.9**	**4.0**	**0.4**	**0.0**	**0.0**	**5.3**

Source: GBA.
Note 1: Original AAI. Technical Report, Table7.3, p77.
Note 2: As advised by Western Power. Excludes real price escalation.
Note 3: Technical Report, Table 7.6, p82.

Based on the cost estimates provided by Western Power, the cost of a new zone substation is approximately $18 million and a new transformer in an existing zone substation is approximately $6 million. Hence there is still provision for approximately 8 new substations or 25 new transformers. Possible combinations of what might be provided for during AA3 are 5 new substations and 10 additional new transformers or 6 new substations and 7 additional transformers.

We think this is a reasonable provision particularly when considered in the following context.

- The timing for additional zone transformer capacity is based on Western Power's POE 10 load forecast, and we have no issue with Western Power's approach to load forecasting. Hence, by definition, there is a 90% probability that the actual load will be lower than forecast in any particular year;

- Even if the load forecast is achieved or exceeded, there will only be an interruption if there is a transformer failure during peak load periods (generally the summer). The load profile in Figure 46 of Western Power's original AAI indicates that Western Power's actual demand only exceeds 90% of its peak demand for less than 1% of the time during the year. In this worst case scenario it may be possible to avoid extended supply interruptions by transferring some load to neighbouring zone substations using distribution transfer capacity. If this is not possible, then rotating customer interruptions during those parts of the day when demand is at a peak may be needed.

- The IAM built into the regulatory framework will enable Western Power to recover all expenditure on network augmentations even if it is greater than provided for in the AA3 revenue cap. Hence, should the Authority underestimate the actual AA3 capacity expansion requirement, the risk to Western Power is low.

Similar to the discussion in Section 4.1.2.1 above, in the context of the acceptable level of business risk faced by Western Power, the risk created by a short term deferral of a transmission supply augmentation, for whatever reason, is low. Furthermore, should an interruption occur over the deferral period, the consequences can be managed to contain the impact on customers. We think Western Power should be comparing the magnitude of this risk with that of other risks it faces in the course of its business, such as the risk of unassisted wood pole failure, and making its investment decisions accordingly.

Our analysis also indicated that Western Power's forecast cost for the construction and expansion of zone substations was, on average, significantly higher than the historic costs of similar projects. We asked Western Power for an explanation but its response[118] was not convincing. We conclude that there is an excessive provision for risk in Western Power's zone substation capex forecast and that it is probable that Western Power will be able to complete a greater volume of work than indicated above with our proposed budget.

4.1.5.2 Kojonup-Albany 132 kV Line

In its Original AAI, Western Power proposed the construction of a 132 kV line between Kojonup and Albany to reinforce the electricity supply to Albany. The forecast cost was $72.9 million. In our Technical Report we suggested that the line be deferred until AA4 as a result of the reduced APR 2011 load forecast[119].

Western Power responded:

> *The Authority's proposed deferral does not consider existing network constraints on supply to the Albany area. There are currently severe restrictions on transfer capability to the Albany region. Demand has already reached the point where there is insufficient transmission capacity to meet the planning criteria in the Technical Rules. Western Power is pursuing a number of options to address this issue including contracting for network control services. As the reduced demand growth has no effect on existing transfer capability constraints, the investment remains in the forecast.*
>
> *To determine the optimum timing of the Albany-Kojonup 132 kV reinforcement, Western Power compared forecast annual network control service costs against annualised network reinforcement costs. On the basis of this analysis, network control service costs were proposed to efficiently defer network reinforcement until 2017.*
>
> *Since the September 2011 proposal, environmental approval requirements have resulted in the project being deferred by one year to 2018. Though deferral does not impact the proposed AA3 network control services operating expenditure, it has shifted transmission capital expenditure by one year, reducing the forecast transmission capital expenditure by $2.6 million[120].*

Without additional information it is difficult to comment in detail on Western Power's response. However we note that:

- Western Power comments that demand at Albany has already reached the point where there is insufficient capacity to meet the planning criteria in the Technical Rules. This appears to suggest that the Technical Rules are predicated on the assumption that network augmentation is the only option available to Western Power to achieve compliance. We dispute this and consider such an interpretation contrary to Access Code objectives.

- Notwithstanding the transmission limitation, NCS will secure the supply to Albany. However, given the distance between Muja and Albany it is likely that the constraint is primarily voltage related and the completion of the new double circuit line between Muja and Kojonup, which we suggested proceed, should provide for some increase in transmission capacity.

- Western Power has not updated its discounted cash flow analysis, which formed the basis for the timing decision in the Original AAI, to account for lower NCS costs as a result of the reduced demand forecast in the 2011 APR and possibly

118 Response to Question GB78.
119 Technical Report, Section 7.2.6, p82.
120 Amended AAI, Section 8.2.1.1, p123.

the impact of the Albany wind farm commissioned in late 2011. This could defer the optimum date for completion of this project.

- The $72.9 million cost of this line is substantial. Should the Southdown mine near Albany proceed, it may be cost effective to construct a new 132 kV line from the mine site as this is much closer to Albany that Kojonup. We have not researched the status of the mine development other than to note that the Grange Resources website still lists it as a current development project. Should there be any chance at all of this project being revived in the medium term it may be prudent for Western Power to continue to use NCS the secure the supply to Albany notwithstanding the results of its economic analysis, until the future of the Southdown mine project is known with more certainty.

Given the information available to us at this time, we are satisfied that the supply to Albany is secure and that deferral of this project to AA4 presents little technical or economic risk to Western Power.

4.1.5.3 Mungarra-Geraldton 132 kV Line

In its Original AAI, Western Power proposed the construction of a 132 kV line between Mungarra and Geraldton to reinforce the electricity supply to Geraldton. The forecast cost was $40.9 million. In our Technical Report we suggested that the line be deferred until AA4 as a result of the reduced APR 2011 load forecast and also noted that the proposed single circuit line was not compatible with the proposed MWEP (Northern Section)[121].

Western Power responded:

> *The Authority's proposed deferral does not account for existing network constraints on supply to the North Country area. There are currently severe restrictions on transfer capability to the North Country region. The demand has already reached the point where there is insufficient transmission capacity to meet the planning criteria in the Technical Rules. Western Power is pursuing a number of options to address this issue including contracting for network control services. As the reduced demand forecast has no effect on existing transfer capability constraints, the investment remains in the forecast.*
>
> *To determine the optimum timing of the Mungarra-Geraldton 132 kV reinforcement Western Power compared forecast annual network control service costs in the area against annualised network reinforcement costs. On the basis of this analysis, network control service costs were proposed to efficiently defer network reinforcement until 2017. There has been no change to the forecast for the required operating or capital expenditure for this project.*
>
> *The Authority also raises concerns that the proposed reinforcement option is not consistent with previous publications on the Mid West Energy Project Northern Section. Planning is underway to identify the optimal solution to ensure reliable and secure supply for underlying demand in the region, as well as accommodating new block loads and new generation. Ongoing planning work may identify that higher capacity options are preferable to given the additional benefits delivered in terms of connecting block loads and new generation.*
>
> *Therefore the costs of the Mungarra-Geraldton 132 kV reinforcement remains in Western Power's AA3 expenditure forecast as it represents the minimum capital expenditure required to address safety and reliability constraints in the Geraldton area relating to underlying demand[122].*

Our position and Western Power's response are very similar to the positions taken for the Kojonup-Albany line and we will not repeat these arguments. The main difference is that

121 Technical Report, Section 7.2.6, p82.
122 Amended AAI, Section 8.2.1.1, p123-124.

Western Power's position on this project, as presented in the Original AAI, is incompatible with the position it has taken publicly in regard to the MWEP (Northern Section). However it argues that the amount proposed is the minimum required to address an existing network constraint.

We reject the suggestion in Western Power's response that the project must remain in the forecast simply because there is an existing network constraint and that a network augmentation is required to ensure compliance with the Technical Rules. The logical extension of this argument is that neither project timing nor the potential for non-network options to defer or replace the project are matters for the Authority to consider as part of its AA3 review. This position is, in our view, untenable.

Based on the information we have seen, we have no doubt that a new circuit will be required between Mungarra and Geraldton, possibly by the end of AA3, and that this will need to be extended to Three Springs in the medium term. It is likely this circuit will be constructed on double circuit towers and initially operated at 132 kV with the main issues to be decided being whether one or two circuits are stung initially and whether or not to allow for future operation at 330 kV. The design, and possibly the timing, of the project will be likely determined not by a need to address incremental load growth around Geraldton but by the net benefits to network users of potential wind and possibly gas generation in the vicinity of Geraldton being able to operate in the wholesale electricity market (WEM). When eventually constructed the MWEP northern section is likely to have more capacity than needed to supply Geraldton load and to cost substantially more than provided for in the Amended AAI capex forecast.

In the 2010 APR the POE10 peak demand in 2018 for the North Country load area was 327 MW while in the 2011 APR the corresponding forecast was only 270 MW, a reduction of 17%. While this significant reduction is likely to be largely due to the removal of one or more block loads and covers a geographic area much larger than Geraldton, it does suggest a potential to defer any network augmentation required only to address incremental load growth around Geraldton. Indeed, the likelihood that any grid reinforcement will cost significantly more than required purely to address incremental load growth strengthens the economic argument to defer the augmentation until the longer term requirement is known with more certainty and in the interim place more reliance on non-network alternatives such as NCS.

4.2 CUSTOMER DRIVEN TRANSMMISSION CAPEX

In our Technical Report we recommended Western Power's net customer driven transmission capex over AA3 be reduced from a total of $155.0 million to $98.9 million as shown in Table 4.4[123]. These adjustments were calculated on the basis of a downward adjustment of gross customer driven capex so that it exceeded the AA2 average by only 10%. We also assumed an average customer contribution of 65% of gross capex[124].

As also shown in Table 4.4, in the Amended AAI Western Power proposed a revised total net customer driven capex for AA3 of $111.5 million, excluding real cost escalation. It accepted our analysis methodology as reasonable but did not accept our assumption that 65% of gross capex should be funded by capital contributions. It stated that a recovery rate of 58% (including the full recovery of transmission line relocation costs) better reflected the actual recovery rates over AA1 and AA2. The difference from our Technical Report analysis is primarily because the analysis in the Amended AAI used an updated F3 forecast of expected 2011-12 capital contributions whereas our Technical Report used an earlier F1 forecast. Nevertheless, it is clear from both analyses that the recovery rate during AA2 was significantly higher than during AA1 and on this basis we consider that the assumption of a 65% recovery rate during AA3 is not unreasonable. Given that customer driven capex is subject to the IAM, we see so reason to further adjust the net customer driven transmission capex proposed in the Technical Report.

123 Technical Report Section 7.3, pp 83-84.

124 The assumption of 65% was derived from Western Power's response to Question GB37. In interpreting this response we assumed that over AA1 and AA2 all transmission line relocations were fully funded by the person requesting the relocation and the capital contributions shown in the table related only to other work. Applying this same approach to the data in Table 47 of the Amended AAI yields an assumed recovery rate of 58%.

Table 4.4: Customer Driven Transmission Capex

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Western Power original forecast	31.4	31.0	30.6	30.4	31.6	155.0	Technical Report Table 7.7
Technical Report proposed net capex	**20.1**	**19.9**	**19.7**	**19.5**	**19.7**	**98.9**	**Technical Report, Table 7.7**
Calculation of assumed adjustment factor to remove real cost escalation							
Gross capex incl. real cost escalation	73.4	74.0	75.2	76.5	79.0		Amended AAI Table 47
Gross capex excl. real cost escalation	72.1	71.2	70.5	69.9	70.7		Technical Report Table 7.1
Adjustment factor to remove real cost escalation	0.98	0.96	0.94	0.91	0.89		
Removal of real cost escalation from Western Power's revised net capex							
Revised net capex incl. real cost escalation	14.0	25.5	26.1	26.7	27.2	119.5	Amended AAI Table 47.
Revised net capex excl. real cost escalation	**13.8**	**24.5**	**24.5**	**24.4**	**24.3**	**111.5**	
Difference from Technical Report proposal	(6.3)	4.6	4.8	4.9	4.6	12.6	

Source: GBA. Note that the data in Table 47 of the amended AAI includes real price escalation and we have adjusted this out in the table.

4.3 TRANSMISSION ASSET REPLACEMENT

4.3.1 Clean Energy Future

Western Power has increased its transmission asset replacement capex by $2.3 million over AA3 to cover the additional cost of purchasing SF_6 gas as a result of the new tax imposed by the Federal Governments Clean Energy Future legislation[125]. We agree that this is a valid cost and that it was not included in the Original AAI. We have not assessed the reasonableness of the amount forecast by Western Power as it is not a material component of the total capex forecast.

4.3.2 Transmission Pole Management

In the Amended AAI Western Power has adjusted its transmission pole management capex to reflect increased contractor costs (see Section 3.3.1 above) and adjusted unit volumes[126]. These cost increases are offset by additional SPOW reductions to give an overall increase in the capex requirements as shown in Table 4.5. These costs include adjustments to the forecast cost of stay replacements, which was shown as a separate line item in Western Power's Original AAI.

Table 4.5: Proposed Increase in AA3 Transmission Pole Management Capex ($ million real, 2011-12, excluding real cost escalation)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Amended AAI capex	11.7	12.4	12.9	13.7	12.5	63.2	Response to Question GB76
Less Original AAI capex	6.4	7.6	9.6	10.5	10.6	44.7	Technical Report Table 7.9
Capex adjustment	**5.3**	**4.8**	**3.3**	**3.2**	**1.9**	**18.5**	

125 Amended AAI, Section 8.2.1.4, p128
126 Amended AAI, Section 8.2.1.5, pp128-129.

We have not reviewed these cost increases in detail since the risks posed by wood pole failure are so serious that we do not think Western Power's response to the issue should be hampered by budgetary constraints. We think that at this stage the focus needs to be on the efficiency with which Western Power implements the program and this is best assessed through an ex-post review at the time of the AA4 revenue reset.

4.4 DISTRIBUTION CAPACITY EXPANSION

4.4.1 Transmission Driven Project Works

In our Technical Report, we suggested that the provision for Western Power's transmission driven distribution project works in the AA3 capex forecast be reduced by $28.5 million (prior to any adjustment for reduced demand)[127]. This is because Western Power's forecast represented 15.3% of transmission supply capex, whereas the corresponding ratio for AA2 was only 4.7%.

In its Amended AAI, Western Power responded:

> *Western Power has analysed a sample of transmission projects across AA1 and AA2 to determine, on average, the associated distribution costs and to asses the method adopted by the Authority's technical consultant.*
>
> *The consultant did not compare the total cost of the transmission project and the related distribution project over their entire project lifecycle. Comparing total project costs determines the average cost ratio between transmission and associated distribution works and accounts for projects that may have been started and completed in different regulatory periods.*
>
> *Western Power's assessment looked at a variety of transmission projects including:*
>
> - *implementation of a new zone substation*
> - *upgrade of an existing zone substation (2nd or 3rd Transformers installations)*
> - *voltage conversions*
>
> *The analysis found that on average, the cost of the distribution works was approximately 26% of the associated transmission project costs. The findings of this analysis are consistent with the estimated costs for transmission and associated distribution projects in AA3[128].*

We asked Western Power to reconcile the relatively low expenditure during AA2 with its analysis indicating that transmission driven distribution works capex was, on average, 26% of its associated transmission driven supply capex. We further asked Western Power to provide the corresponding expenditure ratios for AA1.

Western Power advised:

> *Western Power has reviewed the data underpinning Geoff Brown's analysis of transmission driven distribution capital expenditure as shown in Table 8.4 of the GBA technical report. We have identified two issues which led Geoff Brown to assume that distribution projects would represent 10% of supply capex:*
>
> 1. *Some distribution projects were categorised as 'distribution HV driven' but are 'transmission driven' when accurately classified, this increases the spend in distribution driven projects in AA2 from $8.4 million (in Table 8.4 of the GBA technical report) to $40.5 million…*

[127] Technical Report, Section 8.3.2, pp

[128] Amended AAI, Section 8.2.2.1, pp130-131.

2. *The expenditure presented in Table 8.4 of the GBA technical report includes land purchase cost as part of the 'transmission supply' capex activity. There are no land purchases in Western Power's AA3 forecast.*

Together these errors underestimate the AA2 'transmission driven distribution capex' and overstate the AA2 'transmission supply capex' which therefore skews the cost comparison between AA2 and AA3[129]*.*

Table 4.6 below reproduces Table 8.4 of our Technical Report but uses Western Power's corrected data for AA2. It also includes the corresponding data for AA1, as provided by Western Power.

Table 4.6: Comparison of Transmission Driven Distribution Capex with Transmission Supply Capex for AA1, AA2 and AA3 ($ million, real 2011-12)

	AA1			AA2			AA3				
	05-06	06-07	07-08	08-09	09-10	10-11	12-13	13-14	14-15	15-16	16-17
Distribution Capex – Transmission Driven	15.9	16.4	12.2	16.4	8.6	15.6	7.4	10.3	13.3	15.6	8.7
Transmission Capex - Supply	79.4	79.7	71.9	96.0	29.4	30.0	20.6	75.8	102.8	109.4	54.0
Distribution %	20%	21%	17%	17.0	29%	52%	36%	14%	13%	14%	16%

Table 4.6 indicates that the 10% assumption in our technical report is unsupportable and also that, while transmission driven capex varies significantly from year to year, the associated distribution capex is much less volatile. We are not surprised by this lack of volatility and acknowledge that the distribution works needed to transfer load to a new zone substation cannot occur until the substation has been commissioned. Furthermore, once load on a critically loaded substation has been relieved, the pressure is reduced and remaining load transfers can occur at a measured pace.

However, we still do not accept Western Power's AA3 transmission supply capex, which is the primary driver of this expenditure and so the transmission driven distribution capex forecast must be reduced to reflect our proposed adjustment to this expenditure driver. Our high level approach to determining a reasonable provision is to use Western Power's AA3 forecast data to determine the appropriate ratio between transmission supply projects and transmission driven distribution costs and to allocate the allowed expenditure equally over each year of the AA3 period. An analysis of Western Power's forecast AA3 capex shown in Table 4.6 indicates a forecast total transmission supply capex of $362.5 million and a forecast total transmission driven distribution capex of $55.3 million. This indicates that transmission driven distribution capex should be 15.2% of transmission supply capex, a significantly higher percentage than proposed in our Technical Report.

The derivation of our proposed revised provision for transmission supply capex is shown in Table 4.7.

129

Table 4.7: Proposed Revised Transmission Driven Distribution Capex ($ million, real 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Transmission supply capex outside CBD after reduced demand reduction[1]	11	37.1	45	29.7	29.5	152.3
Cook Street Transformer[1]	2.3	10.1	1.1	-	-	13.5
New Bennett Street substation[2]	0.4	1.0	10.6	10.3	35.5	57.8
Complete Joel Terrace 132 kV conversion[2]	0.7	4.4	9.9	0.9	-	15.8
James Street - single transformer[2]	0.1	0.3	0.9	5.9	13.2	20.4
Adjusted transmission supply capex	**14.5**	**52.9**	**67.4**	**46.8**	**78.2**	**259.8**
Adjusted transmission driven distribution capex (15.2% of above total equally distributed per year)	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**39.5**
Technical Report transmission driven distribution capex[3]	1.3	4.3	4.6	3.0	2.9	16.1
Adjustment to Technical Report capex	**6.6**	**3.6**	**3.3**	**4.9**	**5.0**	**23.4**

Source: GBA.
Note 1: Table 4.3.
Note 2: Table 4.1
Note 3: Technical Report, Table 8.6, p97 (including adjustment for reduced load growth).

4.4.2 Reduction in Demand Growth

In Section 8.3.5 of our Technical Report, we proposed a 20% reduction in Western Power's forecast capex for high voltage distribution driven capacity expansion projects, to reflect the reduction in the forecast peak demand at the end of AA3. As this was only half the forecast reduction in the demand growth over AA3 that Western Power's capacity expansion capex must provide for (see Section 2.4 above) we considered this very reasonable and that it would provide some ability to address known weak spots in the network.

Western Power responded:

> *The Authority's approach incorrectly assesses the impact of a reduction in the system wide forecast peak demand….*
>
> *HV distribution works, which the Authority's technical consultant has referred to as 'minor distribution capacity expansion projects'[130], are aimed at addressing:*
>
> - *over-utilisation of distribution feeders (greater than 80%)*
> - *voltage compliance issues on long country feeders*
>
> *Over-utilisation of distribution feeders was recognised as an issue by the Authority's technical consultant…*

We see no reason to change our view on what is a reasonable provision for AA3. We note that, while not a primary driver, reduced voltage drop on country feeders will be a benefit of the $89.1 million of asset replacement capex on distribution conductor management and that distribution capacity expansion capex is subject to the IAM.

4.5 DISTRIBUTION ASSET REPLACEMENT

In its Amended AAI, Western Power has revised its AA3 distribution asset management capex budget to provide for its recently negotiated alliance contractor rates (discussed in

[130] This line item used the terminology "minor projects" in Western Power's forecast spreadsheet.

Section 3.3.1 above) and the new pole reinforcement strategy discussed in Section 3.3.2)[131]. We have not examined the revised budget in detail as we are hesitant to propose reductions to the distribution asset replacement forecast, given the poor condition of much of Western Power's distribution network. We note that 97% of the proposed increase relates to the new pole reinforcement strategy that has been developed in conjunction with EnergySafety and that most of these costs will now be subject to the IAM. We further note that the proposed increase includes additional SPOW efficiencies that were not provided for in the original forecast.

The impact of these changes is shown in Table 53 of the Amended AAI, which included the impact of real cost escalation. Our proposed adjustment, excluding real cost escalation is shown in Table 4.8 below.

Table 4.8: Additional AA3 Capex for Distribution Asset Replacement ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Amended forecast.	208.6	224.5	230.8	240.4	249.0	1,153.4	Response to Question FD16
Original forecast.	157.7	166	170.8	179.6	190	864.1	Technical Report Table 8.1
Adjustment to original forecast.	**50.9**	**58.5**	**60.0**	**60.8**	**59.0**	**289.3**	

4.6 DISTRIBUTION REGULATORY COMPLIANCE

4.6.1 Accelerated Streetlight Switch Wire Program

Overhead streetlight switch wires are used to switch streetlights from streetlight control boxes and provide power for the streetlights. The streetlight switch wire replacement program aims to remove streetlight switch wires in poor condition, which have the potential to cause electric shocks and streetlight outages. Western Power allowed $7.0 million capex for this program in its Original AAI forecast to cover the cost of this program.

Western Power has reassessed this program's risk ranking following the serious incident in Geraldton in January 2011, which resulted in a fatality[132]. It is now proposed to accelerate the rate of program implementation and this requires the allocation of additional capex over and above that provided for in the Original AAI. This is in addition to the extra opex discussed in Section 3.5.5.

We agree with this adjustment, which is incorporated into Table 4.9 below, consistent with the treatment in the Amended AAI.

4.6.2 Other Distribution Regulatory Compliance Expenditure

In its Amended AAI, Western Power has adjusted its distribution regulatory compliance expenditure to accommodate changes to the stay wire replacement program agreed with EnergySafety and also to provide for the renegotiated alliance contractor rates[133]. As noted in Section 4.5, we are hesitant to propose reductions to Western Power's distribution asset replacement capex, given the relatively poor condition of the existing network.

Western Power's proposed adjustment to its distribution regulatory compliance capex forecast for AA3 is shown in Table 55 of its amended AAI.

131 Amended AAI, Section 8.2.2.2, pp132-134.
132 Amended AAI, Section 8.2.2.3, pp136-137.
133 Amended AAI, Section 8.2.2.3, pp135-136.

Table 4.9: Additional AA3 Capex for Distribution Regulatory Compliance ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Amended forecast	114.0	112.2	111.5	82.7	87.9	508.2	Response to Question FD16.
Original forecast	99.1	103.4	103.6	72.7	78.4	457.2	Technical Report Table 8.1
Adjustment to original forecast.	**14.9**	**8.8**	**7.9**	**10.0**	**9.5**	**51.0**	

4.7 DISTRIBUTION SCADA AND COMMUNICATIONS – TYPE 1 OBLIGATIONS

Compliance with Type 1 obligations is discussed in Section 3.5.4 above. Western Power further proposes additional capex of $1.3 million to introduce a low voltage distribution management system as part of system upgrades to the ENMAC296 system at the East Perth control centre.

In Section 3.5.4 we did not support the inclusion of significant expenditure in the AA3 opex budget purely to support the management of Western Power's Type 1 obligations. The amount of additional capex required for the same purpose is not large and we have therefore not examined the requirement for this funding in detail. However, Western Power has indicated that the expenditure would increase its ability to monitor its low voltage network from its ENMAC system. An enhancement of this nature could potentially help Western Power ensure compliance with its Type 1 obligations using its existing resources, possibly by ensuring that operators responsible for managing the high voltage network are at least aware of where customers using life support equipment are located.

We suggest the additional expenditure be allowed. This adjustment is shown in Table 4.10.

Table 4.10: Additional SCADA and Communications Capex for ENMAC System Enhancements ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
ENMAC System Enhancements	0.4	0.6	0.3	-		1.3

4.8 AMENDED METERING CODE

In Section 8.2.2.5 of its Amended AAI, Western Power is proposing to increase its forecast AA3 capex to include $12.5 million for high voltage interval metering to be installed at Verve Energy's generator sites. In August 2011, the Office of Energy published a final report detailing amendments to the Electricity Industry Metering Code 2005. This included an amendment to clause 3.14 to remove the exemption that had allowed for metering installations commissioned prior to the commencement of the Code. This amendment affects licensed generators' metering installations, primarily Verve Energy, which does not currently have interval metering in place at a number of its generation sites. The amendment requires the majority of Verve sites to install meters capable of meeting the accuracy requirements of the Metering Code before 30 June 2017.

Western Power considers that these costs are the responsibility of Verve Energy. However it has included these additional costs in its capex forecast in case Western Power must pay these costs.

This position differs from the Original AAI where Western Power stated in Section 8.10.1:

> *This recommended change, which had not previously been considered in the April 2011 Recommendations report or April 2010 Issues Paper released by the Office*

> *of Energy, would require expenditure to be included in the AA3 submission to install interval meters of the accuracy required at all of Verve Energy's power stations. Subject to NFIT assessment, the costs to install the meters may require a capital contribution from Verve Energy.*
>
> *We have not yet had an opportunity to fully cost the installation of the proposed Verve metering, and to consider the extent to which that cost should be recovered through reference tariffs and/or customer contributions. We anticipate costs to be more than $10 million. We expect that these costs and associated benefits will be subject to a regulatory impact assessment.*

It is not within the Terms of Reference of this review to comment on whether or not these costs should be paid by Western Power. However, the question of whether or not provision should be made in regulatory forecasts for possible new costs that could arise as a result of legislative or regulatory changes often arises in this type of review and we generally advise regulators that they should be very reluctant to approve such costs. This is because we think monopoly service providers should resist legislative changes that adversely affect their costs to the extent that service providers in a competitive environment would reasonably be expected to do so. If provision for such costs is included in regulatory forecasts, the incentive for a monopoly service provider to resist the changes is reduced. Alternatively, should the changes not eventuate, the service provider could capture a windfall gain.

However, should the Authority not allow these costs, and Western Power eventually has to pay, it is not clear how it could recover the expenditure. Clauses 6.6-6.8 of the Access Code provides for changes to the target revenue as a result of "unforeseen events" while clauses 6.9-6.12 provides for changes as a result of changes to the Technical Rules. There do not appear to be provisions allowing Western Power to recover costs resulting from changes to other legal or regulatory instruments.

In its Original AAI, Western Power indicated that it would recover these costs under the provisions of clause 6.6-6.8 of the Access Code. However, these clauses are written around force majeure events and the proposed change to the Metering Code does not fall within what is normally understood to be a force majeure event. Nevertheless, the definition of *force majeure* in the Metering Code glossary is sufficiently wide that it may cover this situation.

4.9 CORPORATE CAPITAL EXPENDITURE

4.9.1 Wood Pole Testing Facility

Western Power's revised AA3 capex forecast includes new expenditure of $2.4 million for the provision of a wood pole testing facility. The cost of operating this proposed new facility is discussed in Section 3.3.3.

The Alliance Power and Data Report estimated the cost of building a new wood pole testing facility to be $1.76 million and we asked Western Power to explain why its forecast was higher than this. Western Power advised that this was primarily due to the planning and development costs that would be incurred by Western Power, which were not included in the Alliance Power and Data estimate.

We propose that these additional AA3 capex costs be allowed by the Authority. This adjustment is shown in Table 4.5.

Table 4.11: Additional Capex for Wood Pole Testing Facility ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
Wood Pole Testing Facility	1.2	1.2	-	-		2.4

4.9.2 Business as Usual IT Capex

In Section 9.2 of our Technical Report, we supported Western Power's requested AA3 capex for SPOW and IT infrastructure, but proposed that its proposed "business as usual" IT capex be reduced to reflect the average annual AA2 expenditure in real terms. This was on the basis that the SPOW project represented a major upgrade of Western Power's IT systems to support industry standard business practices and we would expect this to reduce, rather than increase, the need for incremental system enhancement.

Western Power responded:

> *As outlined by the Authority's technical consultant, Western Power utilises its 'IT Business As Usual' expenditure to undertake ongoing minor business system enhancements. Increases compared to AA2 period and in the later years of AA3 are to accommodate the need to undertake minor enhancements of new systems, which were previously delivered by the enterprise systems modernisation program.*
>
> *…increases in IT Business As Usual expenditure over the latter years of AA3 correspond with the finalisation of several Enterprise System projects. Western Power has demonstrated the efficient spend on the Enterprise System projects and therefore forecast incremental increases in maintenance costs to support the programs are justified.*
>
> *In the context of the wider IT capital expenditure, the AA3 forecast continues to be constrained below level of expected demand to force prioritisation of candidate projects and avoid excessive tactical spend, in line with Western Power's governance process for IT projects.*

We interpret this response as saying simply that the new IT systems introduced under the SPOW (also called Enterprise Systems) program are going to require more maintenance than the obsolete legacy systems they replace. However, Western Power has not indicated why this should be the case – it is not the case for physical assets and we question why IT assets should be different.

One issue could be that Western Power has focused on purchasing and installing the new systems and has given inadequate attention to how the systems will be used to support its core operations. As a result it is expecting software modifications to be needed once Western Power starts to integrate these new systems into its operational processes. We have already noted, for example, that the design of the field survey data capture project does not appear to have considered maintenance of the enhanced database. If this is a problem, we suggest that it is a project development shortcoming and that customers should not subsequently be called on to cover the cost of rectifying the issues that arise as a result.

4.9.3 Type 1 Obligations

In its Amended AAI, Western Power has requested an additional $2.7 million capex over AA3 for software upgrades to its ENMAC and DNAR systems to provide visibility of the low voltage network[134]. We support this request for the reasons discussed in Section 4.7. This adjustment to the capex forecast in the Technical Report is shown in Table 4.12.

Table 4.12: Additional IT Capex for ENMAC and DNAR Software Upgrades ($ million real, 2011-12)

	2012-13	2013-14	2014-15	2015-16	2016-17	Total
ENMAC And DNAR IT Enhancements	0.8	1.1	0.5	0.1	0.1	2.6

[134] Amended AAI Section 8.2.3.2, p140.

4.9.4 People and Culture Plan

In its Amended AAI, Western Power has included $2.2 million for the development of IT and system enhancements required to ensure the success of the people and culture initiative. This expenditure will enable:

- development of an online system for managing performance appraisal and development plans; and
- automated HR forms and other system enhancements to promote simplified human resource policies and processes.

As indicated in Section 3.6.1, we think the cost of this program should be funded by the shareholder.

4.10 SUMMARY OF PROPOSED ADJUSTMENTS TO TECHNICAL REPORT

In this section we summarise the overall impact of the capex adjustments discussed in this chapter of this report on the forecast capex in our Technical Report.

4.10.1 Transmission Capex

We suggest the adjustments shown in Table 4.13 below to the AA3 transmission capex forecast proposed in our Technical Report.

Table 4.13: Proposed Revisions for the AA3 Forecast Transmission Capex ($ million, real 2011-12, excluding real cost escalation).

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
East Perth to new Bennett Street Substation - two 132kV cable circuits	-	-	0.5	0.7	4.9	6.1	Table 4.1
New Bennett St Substation	0.4	1.0	10.6	10.3	35.5	57.8	Table 4.1
Hay Street to Milligan Street 132 kV cable	0.1	0.4	1.5	5.1	0.6	7.8	Table 4.1
Complete Joel Terrace 132 kV Conversion	0.7	4.4	9.9	0.9	-	15.8	Table 4.1
James Street - Single Transformer	0.1	0.3	0.9	5.9	13.2	20.4	Table 4.1
Impact of modified adjustment for reduced load growth	0.9	4	0.4	-	-	5.3	Table 4.3
Clean Energy Future	0.4	0.4	0.4	0.5	0.5	2.2	Section 4.3.1
Pole Management	5.3	4.8	3.3	3.2	1.9	18.5	Table 4.5
Total Adjustment	**7.9**	**15.3**	**27.4**	**26.6**	**56.7**	**133.8**	

4.10.2 Distribution Capex

We suggest the adjustments shown in Table 4.14 to Western Power's AA3 distribution capex forecast proposed in our Technical Report.

Table 4.14: Proposed Revisions for the AA3 Forecast Distribution Capex ($ million, real 2011-12, excluding real cost escalation).

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Transmission driven	6.6	3.6	3.3	4.9	5.0	23.4	Table 4.7
Asset replacement	50.9	58.5	60.0	60.8	59.0	289.3	Table 4.8
Regulatory Compliance	14.9	8.8	7.9	10.0	9.5	51.0	Table 4.9
SCADA and Communications	0.4	0.6	0.3	-		1.3	Table 4.10
Total	**72.8**	**71.5**	**71.5**	**75.7**	**73.5**	**365.0**	

4.10.3 Corporate Capex

We suggest the adjustments shown in Table 4.15 to Western Power's AA3 corporate capex forecast proposed in our Technical Report.

Table 4.15: Proposed Revisions for the AA3 Forecast Corporate Capex ($ million, real 2011-12, excluding real cost escalation).

	2012-13	2013-14	2014-15	2015-16	2016-17	Total	Reference
Wood pole testing facility	1.2	1.2	-	-		2.4	Table 4.11
ENMAC And DNAR IT Enhancements	0.8	1.1	0.5	0.1	0.1	2.6	Table 4.12
Total	**2.0**	**2.3**	**0.5**	**0.1**	**0.1**	**5.0**	

5. AA2 CAPITAL EXPENDITURE

5.1 MOBILE WORK FORCE SOLUTIONS

In our Technical Report[135] we concluded that we were not satisfied that the $5.7 million cost overrun on the first phase of the mobile workforce solutions project met NFIT requirements and noted that there had been a $1 million cost overrun on the initial budget allocation for this phase without proper approval being given in accordance with Western Power's project implementation procedures.

Western Power does not accept this assessment and the Amended AAI provides detailed reasons why it considers this capex should be included in the AA3 opening capital base[136]. We have therefore further assessed the documents provided to us by Western Power on this project for our original review.

- The first document was a Statement of Program Intent dated 30 June 2009. This estimated the cost of the SPOW program as $8 million for a full rollout over AA2 and is discussed in Section 3.9.1.

- The second document was the first business case dated November 2009. This was for $3 million expenditure to carry the MWS project through to 30 June 2010 with the objective of:

  - Completing the roll-out of the MWS for distribution wood pole inspections and developing a strategy for extending the use of the system to other maintenance activities. This extension to other activities would be implemented over the following two years of AA2 (after 30 June 2010) and additional funding for this would be sought in subsequent business cases. The business case did not include a cost benefit analysis but estimated opex benefits from implementation of the complete MWS program to be at least $10 million per year. Capex savings would exceed $4 million per year.

    The document supported the benefit estimates by quoting published claims of the benefits captured by implementation of similar systems by Yorkshire Water in the UK, the Lower Colorado River Authority in the US and FortisAlberta in Canada. Interestingly, no Australian service provider was quoted and only one of the three quoted companies is an electricity network operator.

    While not clear from the information provided, we assume that the business case was approved by the Managing Director, as the cost estimate did not exceed the threshold requiring Board approval.

- The third document was dated March 2011 and was a business case / change request for an additional $2.2 million to cover expenditure on the MWS project through to April 2011. It explicitly did not include approval for funds to be spent of the project after that date. The business case stated that the MWS project *had already overspent its approved budget by $1 million* and had been *reported as red against budget in the Program Status Report since 1 July 2010.* The business case requested funding of $1.8 million to complete the wood pole inspection component of the project (including the $1 million unapproved overspend). At the time, this component was expected to "go live" in April 2011. There was also $400,000 for preliminary work to investigate extension of the project to include other components of the maintenance effort.

  Problems with the project, as reported in the business case, included:

135 Technical Report, Section 5.3.2.2, pp56-57.
136 Amended AAI, Section 7.2.1.1, pp91-93.

  - Incompatibility of the MWS software with the current version of Western Power's Ellipse business information software. We think this problem should have been foreseen – the primary reason for the selection of the MWS software was that it was developed by Mincom, the provider of Ellipse. The two packages were designed to be compatible and it was always known that the Ellipse software was to be upgraded as part of the SPOW program;
  - Fluidity of the project business requirements;
  - Allocation of insufficient business resources to the project – and when appropriate resources were provided the solution was changed "to better suit the business";
  - Lack of experience in the team in the implementation of mobile solutions, which meant the team "learnt from [its] mistakes after [it] made them";
  - Inappropriate leadership and direction; and
  - Resignation of the project manager in November 2010.

  Options considered in this business case included stopping the project and limiting the scope of the project to rolling out the wood pole inspection component. The business case also covered actions to be taken to address the problems that the project had encountered. Significantly, there was nothing in the business case to indicate that there was any impediment to a full roll out of the wood pole inspection component by April 2011. As will be seen below, only a pilot roll out was actually achieved by that time and further resources were needed to complete a full roll out of the wood pole component.

  In this context, from a process implementation perspective, two points are of note.

  - The business case was dated March 2011, only a month prior to completion of the work that was the subject of the document. While it appears that much of the content was written earlier, by the time the business case was completed and submitted it should have been clear that the project was in further trouble and that only a pilot roll out would be achieved; and
  - By the time the business case was approved most of the funds would have already been spent. The Managing Director was effectively presented with a fait accompli for retrospective approval.

- The fourth document was dated July 2011 and was an interim business case / change request to allow funding to be approved for continuation of the project while a full business case for completion of the project was finalised. The business case was for $3.4 million to cover project expenditure between 1 May and 30 September 2011. The purpose was to bridge the gap before the full business case was approved.

  In this business case the wood pole inspection component of the larger project had been split into two phases. The first phase involved modification of the solution to incorporate the "significant" learning from the pilot project and deployment of the modified solution to all wood pole inspection crews. The second phase was to implement changes made to the software to streamline the quality control process and extend the user base to include the Western Power Quality Control Mentors. The focus of this phase was on improving the quality and timeliness of inspection data. The funding in this business case included completion of Phase 1 and development of Phase 2 to the point of testing the software modifications. The business case also included extending the solution on a pilot basis to cover the inspection of current transformers, voltage transformers and surge arrestors.

- The final business case, which required Board approval, was dated August 2011 and was for $10.9 million to cover funding on the project between October 2011 and September 2012. This is a much more comprehensive document that, for the first time, applied the net benefits rather than safety and reliability component of the NFIT to demonstrate compliance of the expenditure with the requirements of the Access Code. The scope of the work to be undertaken includes completion of the roll-out of Phase 2 of the wood pole inspection component by February 2012 and development and application of the solution to other components of the inspection program using a phased and prioritised approach.

  The business case also noted the low morale of the project team due to the slow progress, inexperience of some resources and the stability / functionality of software delivered to date.

The problems that have beset this project do not reflect well on Western Power's ability to effectively manage the implementation of complex IT systems. As of September 2011 the wood pole inspection component, which was originally forecast to be implemented by June 2010 for a cost of under $3 million, had (under a best case scenario) been only partly implemented for a cost of up to $8.6 million. In the course of project implementation, Western Power's expenditure management procedures had been compromised to the extent that the Managing Director signed off approvals for significant budget over-runs on a retrospective basis. Because of the incremental approach to signing off these over-runs, the total cost of this project component was well in excess of the $5 million threshold for which Board approval is required, yet we have seen no evidence of the Board being formally advised of the status of this project component. It is also difficult not to conclude that, for much of the project implementation, the project team was out of its depth.

It is possible that the original project budget was unrealistic, reflecting misplaced optimism and a lack of awareness of potential pitfalls. Notwithstanding Western Power's contrary view, as expressed in the Amended AAI, we consider that the amount of research undertaken prior to submission of the first business case was inadequate and our suspicion that this was, at least in part, due to the desire to respond quickly to external stakeholder criticism of Western Power's wood pole management practices, remains.

We are not suggesting that staff within Western Power have not acted in good faith and we are not trying to attribute blame. However, under the terms of reference for this review we are obliged to form an opinion on whether mistakes were made that should have been avoided and whether the cost of these mistakes had been material. Our view, based on the evidence we have seen, is that this is the case in respect of the MWS project.

5.2 OTHER SPOW COST OVERRUNS

Leaving aside the overrun on the MWS project discussed in Section 5.1, our Technical Report noted that at the time of the AA2 review, the forecast capex for SPOW was $68 million. In the Original AAI, Western Power reported that its expected total SPOW capex during AA2 was $82.7 million. We commented that we only reviewed 44% of the total SPOW capex and, in the light of our findings on the MWS project, we were unable to form an opinion on the efficiency of those projects we did not review[137]. In its Draft Decision the Authority decided to allow only the $64 million in the original SPOW budget to be included in the opening AA3 capital base.

Western Power provided summaries of the current status of three major SPOW projects that we did not review and these are individually discussed in the following sections. These assessments are necessarily high level – a more detailed assessment would

[137] Technical Report, Section 5.3.2.2, p57.

require examination of additional project documents, including business cases, and time precluded this.

5.2.1 Equipment and Works Management Data Warehouse.

5.2.1.1 Purpose

The equipment and works management data warehouse (EWD) will provide a single repository for asset data for asset data on a common platform accessible to all parts of the business. Presently this information is held by Western Power in a large number of bespoke databases within the business.

5.2.1.2 Cost

The estimated cost of the project as included in the AA2 capex forecast was $6.63 million. In the approved business case this was increased to $7.87 million (+19%) and then through change control to $8.04 million (+21%).

Expected expenditure in AA2 is $7.19 million, with the balance to be spent during AA3. Western Power currently expects to complete the project within the current project budget.

5.2.1.3 Schedule

The project was originally scheduled for completion by June 2012, coinciding with the end of AA2. There has been some slippage on this program and implementation will be completed in the early part of AA3.

5.2.1.4 Comment

- We accept the justification for project implementation. However, it appears that in the business case Western Power indicated that the project would pass NFIT using the safety and reliability test. We suggest that this is not the relevant test – the net benefits test, which requires the cost of the system to be assessed in relation to the benefits that it would provide the business, is more appropriate. However, we would be surprised if this project could not pass a net benefits assessment.

- The budgeted project cost is now 21% higher than the AA2 estimate. Western Power indicates that this is because the AA2 estimate was high level and additional costs were identified during the business case development process. This is plausible. It is also possible that the business case identified additional features that were not included in the A2 estimate, even to the extent of "gold plating" the solution. We have no evidence of this (for this project) but note that a robust net benefits assessment could have provided the Board with an assurance that there was no gold plating.

- Western Power's F1 assessment of actual 2012 cost (based on actual expenditure at the end of the first quarter) put the AA2 expected capex on this project at $6.13 million (DM# 6621900, Table 3) whereas the compliance summary dated May 2012 (DM# 8600598, p3) states that actual AA2 capex will be $7.19 million. This could indicate that some expenditure on this project has been brought forward from AA3.

- Project implementation involves data migration from the existing disparate databases to the new system. Hence it could appear significantly less complex than the MWS system discussed in Section 5.1 above, where the full roll-out requires the cooperation of Western Power's entire maintenance work force including contractor staff. We think the potential for cost overruns on this project is correspondingly lower.

- We have seen nothing on this project to indicate that the actual AA2 capex should not be included in full in opening AA3 capital base.

5.2.2 Ellipse 6.3

5.2.2.1 Purpose

Mincom Ellipse is Western Power's core business resource planning and has been used by Western Power since 1999. It supports the organisation's core requirements across all streams of the business including:

- Asset and works management;
- Materials / logistics;
- Finance; and
- HR / payroll.

The purpose of the project was to upgrade from Ellipse 5.2.3.8 to Ellipse 6.3. This was critical to ensure vendor support arrangements were within Mincom's recommended supported version window (noting that the full standard support was no longer available with version 5.2.3.8) and to provide new functionality.

We accept the need for the upgrade.

5.2.2.2 Cost

The estimated cost of the project as included in the AA2 capex forecast was $4.29 million. In the approved business case this was increased to $4.50 million (+4.9%), although approval was given to sped up to $5.63 million (+31%) due to the extent of cost uncertainty at the time of approval. With approved variations, the final project budget was $6.10 million (+42%).

The final cost of the project was $6.46 million, 50% higher than the original project budget and 6% higher than the final approved budget.

5.2.2.3 Schedule

The project was originally scheduled for completion in October 2010. The base upgrade was completed on schedule while the remaining scope items were completed in September 2011.

5.2.2.4 Comment

- The 50% cost overrun on the AA2 planning estimate appears high given that the project was simply an upgrade to an IT system that was already in use. It also seems to have been seen by Western Power as an unusually complex project to implement. We think this is likely due to the decision to include additional modules to the upgraded package. It is not clear whether these additional modules were provided for in the AA2 estimate.

- This project was affected by many of the issues that affected the MWS project discussed in Section 5.1. Western Power reports that

  The total costs exceeded the business case estimate and the upper limit due to:

  - Significantly greater effort than planned in the business case to migrate customisations and reports and to configure and test the new payroll modules;

- Unavailability of key business resources planned in the business case, which were replaced with higher cost external resources;
- The loss of key resources, most importantly the Project Manager (who resigned from Western Power) and key Business Analysts (who were deployed to higher priority projects).
- The engagement of an external service provider at a higher unit cost and for a longer duration to allow the resources to acquire the necessary knowledge and understanding of the project was not factored into the business case.

5.2.3 NetCIS 3 Implementation

5.2.3.1 Purpose

The Network Customer Information System (NetCIS) is a network billing and customer relationship management solution, eliminating the dependency on Synergy for billing data and enabling improvements in processes supporting customer initiated work and in customer service activities.

NetCIS has been implemented in three phases. The third phase, NetCIS3, is the subject of this NFIT Compliance Summary. NetCIS3 implements the learning from NetCIS2 to expand functionality to stakeholders, further users and customer segments. NetCIS3 will capitalise on the implementation of a new geographical Information System (GIS), and works and asset management systems to bring together customer and network data, effectively integrating the customer into network operations and planning.

5.2.3.2 Cost

The estimated cost of the project as included in the AA2 allowed capex was $2.65 million. In the approved business case this was increased to $3.90 million (+47%). With approved variations, the final project budget was $4.50 million (+70%).

The final cost of the project was $4.45 million, marginally below the final approved budget. This is significantly below the expected amount in Western Power's earlier F1 forecast based on the actual 2011-12 expenditure as at the end of September 2011. This forecast the expected cost of the project at $5.9 million, which would have been more than double the provision in the AA2 allowed capex.

5.2.3.3 Schedule

The project was originally scheduled for completion in December 2011 and actual completion was May 2012.

5.2.3.4 Comment

The extent of the cost overrun on the AA2 estimate is the highest of any of the three projects reviewed in this Section 5.2. Western Power has provided little information on the reasons for the overrun other than to note that changed timing, changes to the project scope and uncosted activities were all contributing factors.

It also seems to us that much of the data held in NetCIS is likely to duplicate data required by Synergy. It is not clear whether the two organisations explored the possibility of sharing a common database. Confidentiality of data required by only one of the businesses might have been an issue but this could have been addressed by outsourcing to an external provider and introducing strict security protocols. Such an approach may have provided significant cost savings to both organisations and may eventually have facilitated the introduction of full retail competition. We note that the AEMO maintains a common customer information system (MSATS) for all market participants as does the New Zealand Electricity Authority.

5.2.4 Conclusion

In all three projects in reviewed in this section, the business case costs were significantly higher than the estimate in the allowed AA2 capex forecast and in all three cases the final project cost exceeded the original business case budget. Western Power notes that in all three cases that the cost estimates in the AA2 capex forecast were based on a preliminary analysis only. While this is undoubtedly true, it does seem that the project scope as outlined in the business cases generally included features that were not allowed for in the original AA2 capex estimate. Without a more detailed examination, we cannot comment on the extent to which this scope creep was justified.

It also seems that Western Power was over-ambitious in that the overall size of the SPOW program during AA2 was significantly greater than its implementation capacity. Costs increased as a result. The scope creep in the development of business cases exacerbated this problem. We note that AA2 coincided with the global financial crisis so resourcing should not have been as big a problem as might have been anticipated at the time the overall program was developed.

In the development of its capex business cases, Western Power requires, amongst other things, an assessment of whether or not the project meets the NFIT requirements of the Access Code. In most cases SPOW projects have been assessed as meeting the requirements of the second leg of the NFIT though the safety and reliability test; that is being necessary to maintain the safety and reliability of the network or Western Power's ability to provide covered services. In our view this is not an appropriate test to apply to capex on business system enhancements. Such expenditure is not needed to maintain the safety or reliability of the network or to provide covered services, but is intended to improve Western Power's operating efficiency. Western Power's management and Board should therefore require SPOW capex business cases to include a robust and quantitative cost benefit analysis in accordance with the requirements of the net benefits test within NFIT, and approval to proceed should only be given if the benefits exceed the costs by a threshold approved by the Board. This discipline would be routinely required by an efficient privately owned organisation operating in a competitive environment and the fact that Western Power is a public sector organisation operating in a monopoly environment is no reason for a lower standard to be applied.

5.3 PICTON-BUSSELTON 132 KV LINE

Western Power's Amended AAI discusses the Authority's decision to remove $102,000 from the capex forecast, being expenditure on the second Picton Busselton 132 kV line[138]. While we proposed this treatment in our Technical Report[139], we have not considered this treatment further in this report as the project has been deferred indefinitely. We assume that these costs are therefore included in the adjustment covered by Required Amendment 7 of the Authority's AA3 Draft Decision.

138 Amended AAI, Section 7.2.2, pp93-94.
139 Technical Report, Section 5.3.2.4, p57.