Geoff Brown & Associates Ltd

REVIEW OF WESTERN POWER'S ACTUAL CAPITAL EXPENDITURE DURING AA3 (2012-2017)

Prepared for

ECONOMIC REGULATION AUTHORITY

Final

10 April 2018

Report prepared by: Geoff Brown

TABLE OF CONTENTS

SECTIONS

DISCLAIMER

This report has been prepared for the Economic Regulation Authority to assist it in its review of Western Power's proposed revisions to its current access arrangement. Geoff Brown and Associates Ltd accepts no responsibility to any party other than the Authority for the accuracy or completeness of the information or advice provided in this report and does not accept liability to any party if this report is used for other than its stated purpose.

Geoff Brown & Associates Ltd
77 Taylors Rd
Mt Albert
Auckland 1025
New Zealand
www.gbassoc.com

Ph/Fax: 64-9-846 6004
Mob: 64-21-466 693
Email geoff@gbassoc.com

Version Control

Version	Date	Comments
Preliminary	18 November 2017	For client information
Draft 1	20 December 2017	For client comment
Draft 2	2 April 2018	Minor changes in response to client comments
Final	10 April 2018	Changes in response to Western Power's review for issues of fact and confidentiality.

EXECUTIVE SUMMARY

GENERAL

Over the course of AA3, Western Power has significantly improved the efficiency of its management of capital expenditure (capex). These improvements relate both to the selection of capex projects and to the use of capital once projects have been committed for implementation. Total capex over AA3 was 22% lower than the approved expenditure forecast at the start of the regulatory period, and despite this, Western Power has still been able to meet or exceed the service levels that it promised its stakeholders. While some capex reductions were due to forecast demand growth not materialising, we think that improved project identification and expenditure management were significant factors in delivering this result.

NFIT EFFICIENCY TEST

The only project we identified that, in our view, did not meet the NFIT efficiency test requirements was the refurbishment of Western Power's head office under Project Vista. This was a legacy project commenced in 2008 and inherited by Western Power's current Board and management. Our analysis indicated that the original Project Vista head office refurbishment budget was exceeded by 40% and the final revised budget by 8%, although the final budget overrun was masked by savings in the depot components of the Vista program, where elements of the original work scope did not proceed.

The reported final cost of the head office refurbishment was $76.5 million, but this cost included only a $1.5 million internal cost component. We estimate the reported project cost would have been approximately $94.8 million if internal direct and overhead costs had been included in accordance with the cost allocation practices that Western Power now applies to network capital projects.

Project inefficiencies arose from the high quality of the internal fit-out, which we note was accepted by the Authority during the AA2 access arrangement review, and a loss of control of project costs during implementation. AA3 capex on the head office refurbishment exceeded $10 million and it is open to the Authority to claw back some of these inefficiencies by not permitting some or all this AA3 capex to be included in the AA4 opening RAB. However, we are not able to recommend the quantity of any such reduction.

OTHER NFIT REQUIREMENTS

The following expenditures included in Western Power's AA4 opening RAB do not, in our view, fully meet other NFIT requirements.

- Western Power has included provisions totalling $7.16 million (real 2017) in the AA4 opening RAB for the future decommissioning and site restoration of the Shenton Park, Herdsman's Parade, British Petroleum and Durlacher substations, which (except for part of the Shenton Park site) are all located on sites that are no longer required for electricity transmission. In addition, it has included a provision of $2.6 million (real 2017) for the removal of asbestos from its offices, depots, and other buildings. Western Power considers that it is entitled to do this by paragraph 16c of the Australian Accounting Standard AASB116, which states that the cost of an asset can include the initial estimate of the cost of dismantling and removing the item and restoring the site on which it is located. Our view is that provisions of this nature are forecast costs that clause 6.49 of the Code precludes from being included in the RAB. Furthermore, there is an admitted error in Western Power's accounting for these costs in its proposal and the intended treatment is still not entirely clear. Nevertheless, we think the treatment proposed by Western Power may lead to the decommissioning costs being over-recovered.

- The business case for undergrounding three spans of the Manning-Osborne Park 132 kV transmission line in Ewen St, Woodlands, concluded that this project did not meet NFIT requirements. We agree with this assessment. However, Western Power has inadvertently included the $2.13 million cost of this project in the AA4 opening RAB. This should be removed.

- Western Power has also advised us that, in its view, $1.78 million (real 2017) of the capex incurred in installing a battery energy storage system at Perenjori as a research and development project may not meet NFIT requirements and should not have been included in the AA4 opening RAB. Nevertheless, we have reviewed the business case for this small-scale project and consider the expenditure to be reasonable and to fully meet NFIT requirements. Removal of this expenditure from the RAB would suggest that the Authority is not prepared to support Western Power undertaking small scale, well designed research and development projects related to the impact of new and emerging technologies on electricity distribution. The business case also indicated that the project would likely qualify for a research and development tax incentive. In this event, we think any tax incentive should be treated as a capital contribution to the project rather than a windfall gain to Western Power.

- Western Power's proposed AA4 opening RAB includes a $6.70 million capitalisation for "intellectual property" for work completed in preparation for transition to the national regime. We do not think this expenditure should be capitalised as intellectual property is an intangible asset rather than a "network asset" as defined in the Code.

ACCOUNTING ISSUES

When Western Power identifies a project, a work in progress (WIP) account is created at the early scoping stage of the project development process. Its regulatory accounts treat WIP as part of the RAB, which means that the expenditure starts to be depreciated immediately after it is incurred. Should it subsequently be decided not to proceed with the project, the amount in the WIP account is journaled out of the RAB. For some projects, the time lag between when an expenditure is incurred and when it is reversed out can be many years. We are not accountants, and detailed consideration of the implications of this treatment is not part of our scope, but we raise these issues for the consideration of the Authority.

- Depreciation of expenditure of an asset that has still to be commissioned is not consistent with paragraph 55 of AASB116, which states that *depreciation of an asset begins when it is available for use, that is when it is in the location and condition necessary for it to be capable of operating in the manner intended by management.*

- We understand that when it is decided not to proceed with a project, expenditure that has been incurred on the project is reversed out of the RAB at its nominal WIP value at the time of reversal. However, the regulatory accounts revalue the RAB annually by the consumer price index and we think the revaluations between the date the expenditure is incurred and the date it is reversed out are left in the RAB. We also note that depreciation is a cost recovered from the regulated revenue base and we do not think that depreciation charged on the expenditure prior to its reversal is returned to network users.

We also note that Western Power has changed its approach to accounting for the cost of decommissioning and site restoration for substations located on sites that are no longer required for transmission purposes. The business case for Herdsman's Parade, for example, treated these costs as non-recurring opex, but Western Power has now capitalised this expenditure.

PRESENT VALUE ANALYSIS

Some of the present value analysis we reviewed assumed project lives of 40-50 years, on the basis that these lives are typical lives for network assets. In our view the assumption of such a long project life is not justified, due to the highly speculative capital cost assumptions over the latter half of such periods. Analysis over such a long project life will invariably favour network augmentations over non-network alternatives and may well result in the installation of excess capacity. We think that the assumed project lives in present value studies should be no longer than 20-25 years.

APPLICATIONS AND QUEUING POLICY

Stakeholders are generally positive about the changes to the applications and queuing policy (AQP) proposed by Western Power. However, some stakeholders have requested detailed review of some of the wording to ensure that the policy cannot be applied in a way that advantages Western Power at the expense of its stakeholders.

We saw no evidence of this and, while we acknowledge that the wording of the policy must be clear and unambiguous, we think the application of the policy is more important to stakeholders than its wording.

We suggest that the concerns raised by submitters would be addressed if a new clause was included that explicitly requires Western Power to:

- act as a reasonable and prudent person in all matters relating to the processing of network access applications;
- act in a manner consistent with the objectives and requirements of the Access Code; and
- be transparent in its processing of access applications and avoid withholding information from applicants without good reason.

For the avoidance of doubt the policy should also state that access applicants have recourse to the disputes procedure in Chapter 10 of the Access Code should they consider that Western Power is applying the AQP in a manner that is inconsistent with this new clause.

1. INTRODUCTION

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

Western Power's current access arrangement (AA3) covers the five-year period from 1 July 2012 to 30 June 2017. On 2 October 2017, Western Power submitted proposed revisions to its AA3 access arrangement that, once approved by the Authority, would apply over the AA4 period from 1 July 2017 to 30 June 2022. The Authority may require Western Power's proposed revisions to be modified before it grants approval.

Under clause 4.28 of the Code the Authority must not approve an access arrangement unless it is satisfied that meets the objectives of the Code and covers all matters specified in chapter 5 of the Code. As part of its review of Western Power's proposed revisions the Authority has engaged Geoff Brown and Associates to provide advice on the following matters:

- whether Western Power's actual capex over the AA3 regulatory period satisfies the requirements of the New Facilities Investment Test (NFIT);
- whether the proposed changes to Western Power's Access and Queuing Policy (AQP) meet the objectives of the Code and, more specifically, the requirements of sections 5.7 – 5.11 of the Code.

The New Facilities Investment Test (NFIT) is specified in clause 6.52 of the Code, which states:

> *New facilities investment satisfies the new facilities investment test if:*
>
> *(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:*
>
> > *(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and*
> >
> > *(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;*
>
> *and*
>
> *(b) one or more of the following conditions is satisfied:*
>
> > (i) *either:*
> >
> > > *A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or*
> > >
> > > *B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;*
> >
> > *or*

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

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

The test in the "first leg" of NFIT, Section 6.52(a), is often referred to as the *efficiency* test and the tests in the "second leg", 6.52(b), are referred to as the *incremental revenue test,* the *net benefits test,* and the *safety and reliability test* respectively. To satisfy NFIT, a project must satisfy the efficiency test in the first leg and one of the alternative tests in the second leg.

An ex-post review of whether Western Power's actual AA3 capex satisfies NFIT is required to confirm that this expenditure can be included in the opening RAB for AA4, since section 6.51A of the Code states that only NFIT compliant expenditure can be included in the RAB. As part of its review of the AA4 access arrangement, the Authority must approve the AA4 opening RAB and the ex-post review of actual AA3 capex informs this decision.

In preparing the advice provided in this report, we have relied on the AA4 access arrangement information (AAI) that Western Power submitted to the Authority in support of its proposed revisions. We also relied on additional information provided to us by Western Power during this review. However, our review was not an audit and we were not required to independently verify, or satisfy ourselves of, the accuracy of the information provided. Therefore, while we clarified information that appeared incorrect or inconsistent, we generally took the information provided by Western Power at face value. It follows that we cannot be held responsible for misleading the Authority if the advice provided in this report is found to be based on the review or analysis of inaccurate or incomplete information provided to us by Western Power.

2. OVERVIEW OF AA3 CAPEX

2.1 INTRODUCTION

As indicated in Section 1, the terms of reference for our review require an assessment of Western Power's actual AA3 capex for compliance with NFIT requirements. We have done this using both top-down and bottom-up analyses. Our top-down analysis involved comparing capital expenditure in different asset categories with both the equivalent expenditure during AA2 and the forecast expenditure for AA3, as approved by the Authority during the AA3 regulatory review. Further explanation was sought from Western Power to justify expenditure that appeared abnormally high. As AA2 was a three-year regulatory period and AA3 lasted five years, expenditure comparisons between the two periods were generally done using average annual expenditure.

A bottom-up approach, where we examined a small sample of individual projects and programs in more detail, supported this top-down analysis.

2.2 TOTAL CAPITAL EXPENDITURE

Table 2.1 and Figure 2.1 compare Western Power's actual capex over for AA3 with its equivalent capex during the AA1 and AA2 regulatory periods, the approved expenditure in the Authority's AA3 final decision, and its proposed expenditure for the AA4 regulatory period. To provide a valid comparison, the expenditures shown are annual averages over the regulatory period[1], and have been adjusted to real 2017 dollars using actual CPI as the escalator. Forecast AA4 capex throughout this report is estimated, to the extent that, where necessary, we have added our estimated real cost escalation and capitalised overheads to the base project costs provided by Western Power.

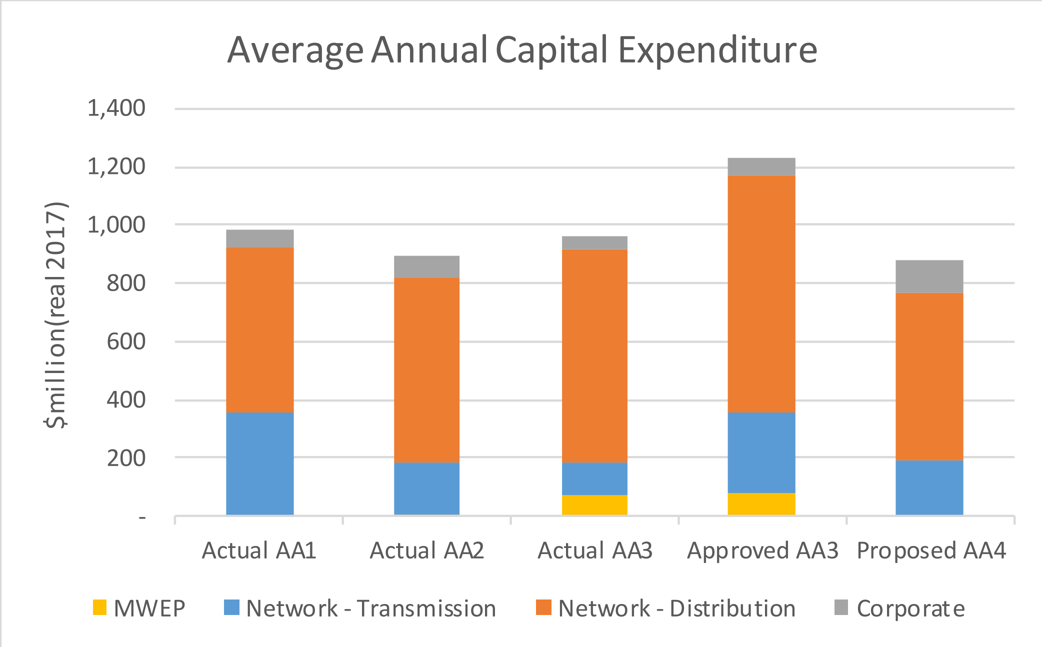
Table 2.1: Total Average Annual Capital Expenditure ($ million, real 2017)

	Actual AA1	Actual AA2	Actual AA3	Approved AA3	Proposed AA4
MWEP		5.95	72.54	76.81	0.10
Transmission[1]	354.98	178.40	111.98	277.84	189.37
Distribution	568.91	635.91	728.88	815.49	575.47
Corporate	62.29	76.46	30.90	62.31	113.77
Total	**986.18**	**896.72**	**944.31**	**1,232.45**	**878.71**

Note 1: Excludes MWEP
Note 2: Includes gifted assets and capital contributions

[1] Average annual expenditure is used to provide a valid comparison across regulatory periods, given that AA1 and AA2 were three-year regulatory periods, whereas AA3 and AA4 are five years.

Figure 2.1: Actual, Approved and Proposed Total Capex ($ million, real 2017)



Western Power's average annual total capex during AA3, while 5.3% higher than during AA2, was 22% lower than the forecast approved by the Authority. Capex in AA3 was higher than in AA2 primarily due to construction expenditure on the Mid-West Energy Project (MWEP), which made up almost 40% of its total AA3 transmission capex and is Western Power's largest one-off capex project in more than 25 years. Western Power is typically spending about 20% of its total capital expenditure on the transmission network, 70% on the distribution system and 10% on corporate support, which includes buildings, IT infrastructure and fleet.

Western Power's total capex since the beginning of AA1 has averaged under $1 billion per year. It is progressively decreasing, with its proposed AA4 capex over 10% lower in real terms than its actual capex during AA1. The increased spend in AA3 did not conform to this decreasing trend only because of the impact of the one-off MWEP.

3. TRANSMISSION CAPITAL EXPENDITURE

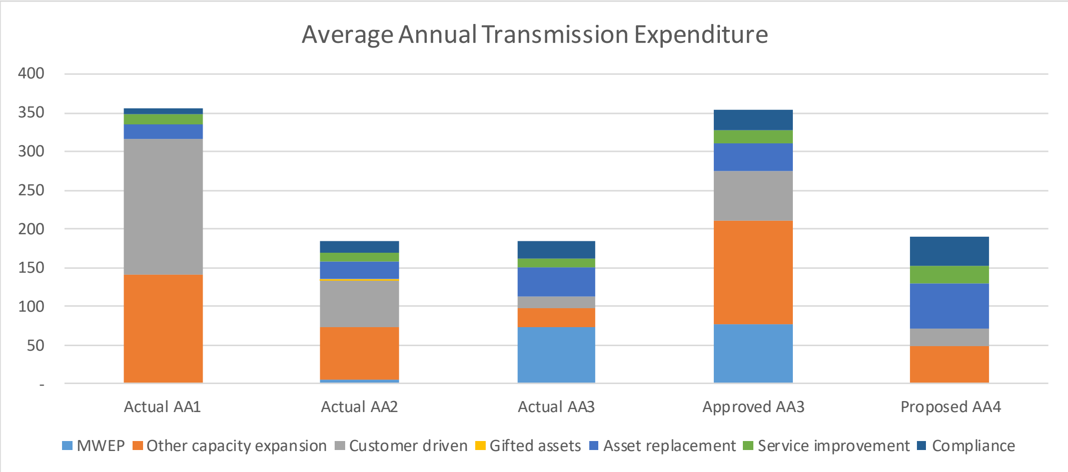
Table 3.1 and Figure 3.1 disaggregate Western Power's transmission capex into its major expenditure categories and compare its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA1 and AA2 expenditure and Western Power's proposed AA4 expenditure.

Table 3.1.: Total Average Annual Transmission Capital Expenditure ($ million, real 2017)

	Actual AA1	Actual AA2	Actual AA3	Approved AA3	Proposed AA4
MWEP	-	5.95	72.54	76.81	0.12
Other capacity expansion[1]	141.82	67.26	25.01	134.52	48.27
Customer and generation driven.	174.23	60.72	15.28	63.21	22.77
Gifted assets		0.57			
Asset replacement	19.83	23.51	37.26	35.40	59.24
Service improvement	12.55	11.48	12.04	16.63	21.68
Compliance	6.56	14.86	22.39	28.08	37.39
Total	**354.98**	**184.35**	**184.52**	**354.65**	**189.47**

Note 1: Excluding MWEP, customer driven expenditure and gifted assets
Note 2: Expenditure includes capital contributions

Figure 3.1: Actual, Approved and Proposed Transmission Capex ($ million, real 2017)



Western Power's transmission capex has averaged under $200 million (real 2017) per year since the beginning of AA2 and accounts for around 20% of its total capital expenditure. This is substantially below the $350 million real that it spent annually in AA1 and forecast to spend in AA3. The nature of this expenditure is also changing over time, with significant reductions in capacity expansion expenditure and increases in asset replacement expenditure, reflecting very little growth in the demand for electricity since 2008[2] and an aging network. The expenditures shown in Table 3.1 understate this trend since the

2 This does not suggest that there is no requirement to expand the network in response to demand growth. While across the network there has been little growth in total demand since 2008, there are still localised areas where demand continues to grow and a need to increase the capacity of parts of the network to accommodate this localised growth.

primary driver for many capacity expansion projects is the need to replace existing assets that have reached the end of their economic life.

Western Power classifies all new assets installed on the network as capacity expansion expenditure, except where an asset is a direct "like for like"[3] replacement of an existing asset. Hence, some projects where the primary driver is asset replacement are classified as capacity expansion, because these projects involve the installation of new assets that are not "like for like" replacements to optimise the configuration of the network. The proposed new 132 kV cable between the Hay and Milligan Street substations in the Perth CBD to allow the retirement of the 66 kV network fed from the East Perth terminal station is a good example.

The MWEP is also a large one-off project that accounted for almost 40% of Western Power's AA3 transmission capex. This is the nature of large transmission projects, where expenditure tends to be lumpy rather than incremental. Figure 3.1 indicates that Western Power has been able to accommodate the large one-off cost of the MWEP without materially exceeding its overall capex budget by deferring expenditure in other categories.

3.1.1 Transmission Capacity Expansion Capital Expenditure

Western Power categorises transmission capacity expansion capex as voltage, thermal management, supply, and land. MWEP expenditure is categorised separately because of the size and uniqueness of the project.

- Capex to maintain the voltage stability of the network and to ensure that voltage levels remain within the prescribed operating envelope for all credible load and generation scenarios, even when a transmission element is out of service due to an unplanned fault or a planned maintenance interruption, is categorised as *voltage*;

- Capex to ensure that the load on network element does not exceed its rated thermal capacity is categorised as *thermal management*;

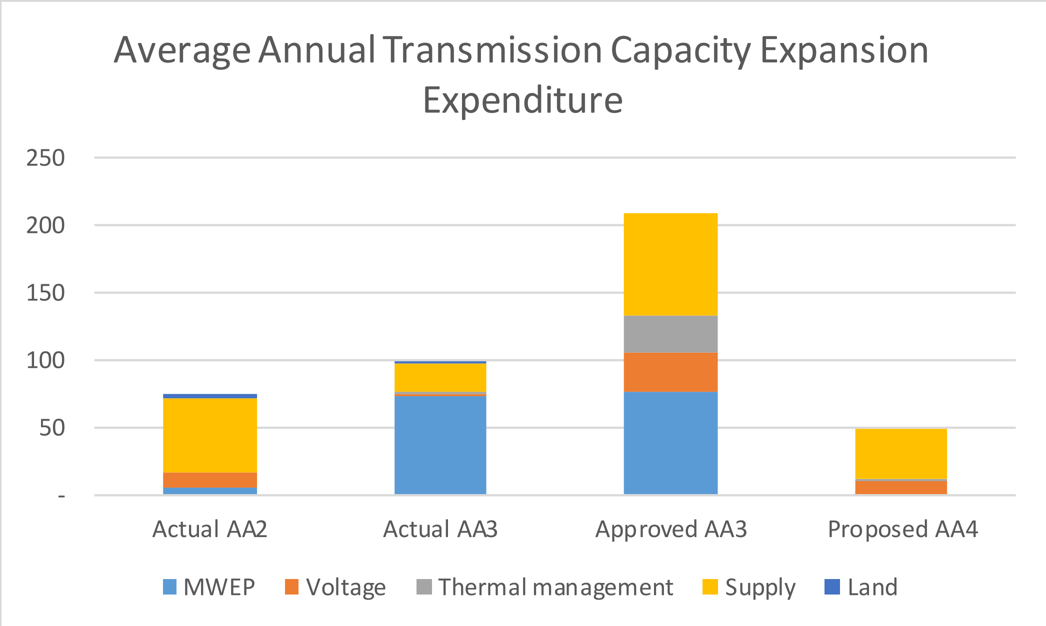
- Capex to ensure that there is sufficient capacity at the interface between the transmission and distribution network to supply the forecast demand is categorised as *supply.* This applies to incremental load – capacity expansions specifically intended to accommodate large block load or generation connections are considered customer driven and may be partly funded by a capital contribution from the proponent; and

- Capex to purchase land or easements for future substations or transmission lines is categorised as *land*.

Figure 3.2 disaggregates Western Power's transmission capacity expansion capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and Western Power's proposed AA4 expenditure.

[3] In this context "like for like" refers to the function and capacity of the asset rather than its design technology. It is good industry practice to replace an existing asset with a modern equivalent, which may use a different technology.

Figure 3.2: Actual, Approved and Proposed Transmission Capacity Expansion Expenditure ($ million, real 2017)



Western Power's total capacity expansion expenditure during AA3 was $488 million, less than 50% of the approved expenditure of $1,043 million forecast at the AA3 regulatory reset. Of this $363 million (75%) was spent on the MWEP, which came in marginally below the AA3 budget. If the MWEP is excluded, then the residual expenditure of $125 million was less than 20% of the approved $622 million forecast.

The demand growth forecast at the time of the AA3 review has not materialised and Western Power is now putting much more focus on quantifying the risk of deferring or not proceeding with a capacity expansion project and on identifying lower cost means of mitigating that risk. This has led to 40 of 68 capacity expansion capital projects in the approved forecast not proceeding during AA3, as shown in Appendix B. Many projects that have proceeded have come in under budget.

3.1.1.1 *Capex on Committed Projects*

Table A3.2 shows the AA3 capex on projects that have been completed or still under construction at the start of AA4. Some of the projects under construction may have been partly commissioned.

We note that the final costs of most of the completed projects shown in Table 3.2 were well below their forecast cost – in some cases the final cost was well under 50% of forecast. While this is evidence that the expenditure was efficient and met NFIT requirements, it calls into question the robustness of the processes used by Western Power to prepare its AA3 forecast and whether the escalation and risk provisions included in its project cost estimates were high.

Table 3.2: Significant AA3 Capacity Expansion Capital Expenditure Projects ($ million, real 2017)

Project	AA3 Forecast	AA3 Actual	Current Status	AA4 Forecast[1]	Comment
New Balcatta substation	5.42	5.09	Complete	-	Efficiencies identified during project development and implementation
MWEP	384.03	362.70	Closeout	0.49	See Section 3.3.1.1
Shenton Park reinforcement	27.94	30.61	Execution	3.43	See Section 3.3.1.2
Busselton capacitor bank	5.34	3.46	Complete	-	Efficiencies identified during project development and implementation
Meadow Springs – 3rd transformer	6.14	5.27	Execution	3.26	Efficiencies identified during project development and implementation
Convert KEM-MRR to double circuit line	4.08	3.30	Complete	-	Efficiencies identified during project development and implementation
South Metro network reconfiguration	49.67	5.62	Execution	0.08	Efficiencies identified during project development and implementation
Uprate JDP-WNO 81 line	6.18	0.40	Complete	-	Efficiencies identified during project development and implementation
Uprate Joel Terrace to 132kV	17.92	15.34	Complete	-	Efficiencies identified during project development and implementation
MJ – Additional transformer	9.89	9.29	Complete	-	
MOR – Additional transformer	4.16	2.04	Complete	-	Savings due to relocated rather than new transformer
Uprate KOJ-ALB 132kV line	-	3.20	Complete		Uprate line due to need to address clearance issues
BSN – Partial conversion to 132kV	9.59	9.34	Execution	0.05	
RAN – 3rd transformer	6.48	3.10	Execution	7.39	Construction underway and will continue into AA4
Uprate under fault rated transformer assets	-	2.08	Execution	0.24	Project not included in AA3 forecast.

Note 1: Base cost provided by Western Power and estimated capitalised overheads.

3.1.1.2 *Capex on Uncommitted Projects*

Table 3.3 shows AA3 expenditure on capacity expansion transmission projects that had still to be committed for construction at the end the regulatory period.

We asked Western Power to clarify its treatment of capital expenditure incurred on a project before it was committed for construction. Western Power responded:

> *When an investment is delivered (whole or in part) through a capital project, the project development lifecycle begins that capital project at Gate 1 with costs captured as construction work in progress (WIP). Capital project costs are not capitalised until the constructed asset is brought into service at Gate 4 (with close out costs capitalised at Gate 5).*
>
> *If at any point between Gate 1 and Gate 4 Western Power decides not to proceed with the delivery of the capital project, the project is cancelled and all associated costs will be expensed, from construction WIP to the [profit and loss account].*

Table 3.3: Capital Expenditure on Uncommitted Projects

Project	AA3 Forecast	AA3 Actual	Current Status	AA4 Forecast[1]	Comment
Joondanna – new substation	-	(2,533)	-	-	Credit due to expenditure incurred in AA2
Hay St – Milligan St Supply Reinforcement	9.36	3.01	Planning	28.82	The Authority recently gave regulatory test approval for this project based on a forecast nominal cost of $38.5 million, including risk. Western Power's AA4 forecast does not include a risk provision.
WGA – 2nd transformer	6.36	(0.01)	-	-	Project deferred due to reduction in peak demand forecast
132kV Picton-Busselton transmission line	33.28	0.84	Scoping	23.24	Project deferred. The installation of a capacitor at Busselton makes the need for this substation less likely.
BUH – 4th transformer	39.32	0.15	Initiation	7.44	Project deferred due to reduction in peak demand forecast
Osborne Park Area – New zone substation	31.35	(0.05)	-	-	Project deferred due to reduction in peak demand forecast
New Bennett St CBD Substation	67.79	1.06	Initiation	75.30	Project scoping costs
KAT – Reactive support	24.10	0.28	Scoping	4.01	Project deferred due to reduction in peak demand forecast
ZTS – new substation	29.80	0.01	-	-	Project deferred due to reduction in peak demand forecast

Note 1: Base cost provided by Western Power and estimated capitalised overheads and real cost escalation.

While Western Power states that AA3 expenditures on uncommitted projects are not capitalised until the project is brought into service, their inclusion in the opening RAB means that depreciation in the forecast regulatory accounts will commence before the asset is commissioned. This is inconsistent with paragraph 55 of Accounting Standard AASB116, which states:

> *Depreciation of an asset begins when it is available for use, that is, when it is in the location and condition necessary for it to be capable of operating in the manner intended by management.*

This aside, we think Western Power's treatment of expenditure on uncommitted projects in its regulatory accounts may result in an unjustified increase in its capital costs.

- As we understand it, once it is decided not to proceed with a project, Western Power journals the value of the WIP for the project out of the capital account and into profit and loss at the value of its nominal expenditure, without considering any revaluations over the intervening period. This treatment leaves the revaluations in the RAB, even though they relate to assets that were never commissioned. This can be seen from the smart grid project, which the Western Power Board decided to discontinue in March 2013. Western Power has calculated a residual AA3 expenditure of $45,000, which it has included this in its proposed opening AA4 RAB, even though there was no residual expenditure in nominal terms.

Table 3.4: Treatment of AA3 Smart Grid Expenditure ($ 000)

Year ending	2013	2014	2015	NFIT Amount
Nominal Capex	781	549	1,330	-
Revalued (real 2017) Capex	841	574	(1,369)	45

We have used this project as an example because Western Power has confirmed the above treatment. While considered in isolation the residual NFIT amount is not material, the impact could become more significant when aggregated across all Western Power's credit adjustments to the RAB. To offset this anomaly in the regulatory accounts, the credit adjustment would need to reflect revaluations from the date the expenditure was incurred rather than from the date of the adjustment.

- Once the expenditure is included in the opening AA4 RAB, the subsequent depreciation is a cost recovered from the revenue cap. If the project does not proceed to construction, the revenue allowed to fund this depreciation will not be returned to users.

Some of the projects shown in Table 3.3, such as the Hay St – Milligan St cable, are almost certain to proceed, whereas Western Power has said that the Bennett St substation will not go ahead. We are uncertain whether the Picton-Busselton transmission line will proceed, given the current low growth environment and the installation of a capacitor bank at Busselton during AA3.

It is possible that there are other credit adjustments to the RAB where there is a residual impact on customers. For example, Western Power's schedule of customer driven transmission projects shows a total $29.68 million (real 2017) credit adjustments. While $21.18 million of this relates to an adjustment between RAB transmission categories relating to the MWEP, the balance appears to be WIP write-offs.

We make no recommendation in respect of this accounting treatment as the scope of our review is limited to the extent to which AA3 expenditure meets NFIT requirements. However, given that we identified it as a possible issue, we considered it prudent to include it in our report for the Authority's consideration.

3.1.1.3 Mid-West Energy Project

The MWEP involved the construction of a double circuit 330 kV transmission line between Pinjar and Three Springs and a 330/132 kV substation at Three Springs. The project had the following objectives:

- to supply planned mining load in the Mid-West region including the Karara magnetite mine, which commenced operation in 2012;
- to provide capacity to allow the connection of new renewable and gas fired generation located in the Mid-West; and
- to provide additional capacity required to supply growing incremental demand around Geraldton.

The Authority provided regulatory test approval for the project in February 2011[4] and NFIT pre-approval for an amount of up to $377.8 million (real dollars as at 30 June 2010) in January 2012[5]. The project was fully commissioned in 2015 and is currently in the closeout phase.

Western Power's actual and forecast closeout expenditure on the MWEP is shown in Table 3.5.

4 *Final Determination on the Regulatory Test for the Mid-West Energy Project (Southern Section);* Economic Regulation Authority, 3 February 2011.

5 *Final Determination on the New Facilities Investment Test Application for the Mid-West Energy Project (Southern Section);* Economic Regulation Authority, 27 January 2012.

Table 3.5: MWEP Expenditure ($ million, real 2017)

Actual AA2	Actual AA3	Forecast AA4	Total
17.86	362.70	0.48	381.04

The approved NFIT amount of $377.8 million as at 30 June 2010 inflates to $436.8 million as at June 2017. This is almost 15% higher than Western Power's actual expenditure on the project.

3.1.1.4 Shenton Park Substation

An analysis of this project, which is still in execution and not expected to be fully closed out until 2018/19, is provided in Appendix A1. We do not consider the inclusion of a $2.48 million provision in 2012/13 for the decommissioning costs of the two 66 kV substations is appropriate and this is discussed further in Section 3.1.1.5 below.

The processes used by Western Power to develop and implement the project were robust and generally in accordance with Western Power's business processes. We therefore consider that all Western Power's expenditure on this project during AA3 meets NFIT requirements, apart from a potential adjustment to correct the treatment of decommissioning costs.

We do not think that Western Power should have relied on A0 cost estimates in its business case analysis[6]. We also do not think it should have assumed a 50-year project life in its net present cost analysis, since costs in the second half of such a period were highly speculative. The logic in the business case was difficult to follow and we are not suggesting that these decisions affected the selection of the final project design for this project.

We also think that it may have been possible to defer the installation of 11 kV capacitors but have seen nothing to indicate that this was considered. Any cost savings from such deferral would have been small relative to the total cost of the project and we are not suggesting this concern be the basis for a reduction in the approved NFIT amount.

3.1.1.5 Decommissioning Provisions

Western Power's breakdown of its AA3 actual transmission capacity expansion expenditure includes four separate line items that are characterised as decommissioning provisions and described as *capitalised decommissioning costs for assets meeting the asset recognition criteria stated in Western Power's capital expenditure and depreciation standard; and in compliance with paragraph 16c of Australian accounting standard AASB116, Property Plant and Equipment.* Western Power has included these provisions in full in its AA4 opening RAB and included the actual decommissioning cost in its analysis, including in its AA4 forecast expenditure.

These entries are summarised in Table 3.6.

6 Western Power's structured project development business process specifies three progressively more accurate cost estimates. An initial A0 cost estimate uses standard building block costs and is considered to have an accuracy of +/- 50%. A scoping phase A1 cost estimate takes project specific factors into account and has an accuracy of +/- 30%. The planning phase estimate is even more accurate (+/-10%) and is the basis for business case approval of the preferred option.

Table 3.6: Treatment of Decommissioning Costs ($ million, real 2017)

Substation	AA3 Decommissioning Provision		AA4 Forecast Decommissioning Cost	
	Project No	NFIT Amount	Project No	Forecast[1]
Shenton Park	T0384182	1.04	-	-
Herdsman's Parade	T0384189	1.45	T0380517	1.26
British Petroleum	T389229	1.18	T0389229	0.21
Durlacher	T043131	3.49	T0416018	3.95

Note 1: Includes estimated capitalised overheads and real cost escalation

Western Power has since advised that the above table misrepresents the accounting treatment. The provision is raised as a separate project number and then as decommissioning expenditure occurs, it is credited to (subtracted from) the provisional amount and debited (added) to the decommissioning project (which in the case of Shenton Park was the construction project discussed in Section 3.1.1.4). We suspect this means that the AA3 NFIT amounts for Shenton Park, Herdsman's Parade and British Petroleum have been overstated as credits relating to decommissioning expenditure incurred in AA3 have not been taken into account. Western Power has indicated that it will correct this in its response to the draft decision.

Western Power has justified its treatment as follows:

- Paragraph 16c of AASB116 provides that the cost of an item of property should include the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located; and

- AASB 137-Provisions, Contingent Liabilities and Contingent Assets provides that a provision shall be recognised where a legal or constructive obligation has arisen from a past event, that will more likely result in outflow of benefits and the amount can be measured reliably. Western Power's legal obligation towards land rehabilitation arises from the completion and/or removal of an asset (past event) and it is highly probable that this obligation will result in the outflow of benefits and that the amount can be measured reliably.

We note that Paragraph 16c of AASB would not normally apply to the construction of new transmission and distribution assets on a greenfield site since it is generally assumed that at the end of an asset's economic life an asset will need to be replaced and the cost of decommissioning and removing the asset would be included in the cost of installing its replacement. Western Power has recognised this and has only capitalised decommissioning provisions when the site is no longer required for transmission purposes.

Notwithstanding Western Power's explanation for its accounting treatment, we have the following concerns.

- Section 6.49 of the Code specifically states that the RAB must not include a forecast new facilities investment. In our view, the decommissioning provisions raised as capital expenditure by Western Power are forecast investments.

- If our understanding is correct (and we accept that it may not be) then when decommissioning expenditure is incurred the expenditure is debited (added to) to a decommissioning account, which is included in the RAB and then fully recovered through depreciation in the normal way. Any recovery over and above this would seem to be unjustified, and therefore a windfall gain to Western Power. The fact that the expenditure is credited against the decommissioning provision at the same time does not change this.

- As the asset is removed without being replaced, there are no ongoing economic benefits to Western Power, so it is not clear that capitalisation of the decommissioning cost is the appropriate accounting treatment. It may be more appropriate to treat the expenditure as an asset disposal cost or to offset it against revenue from the disposal of the site. We have no view on this.

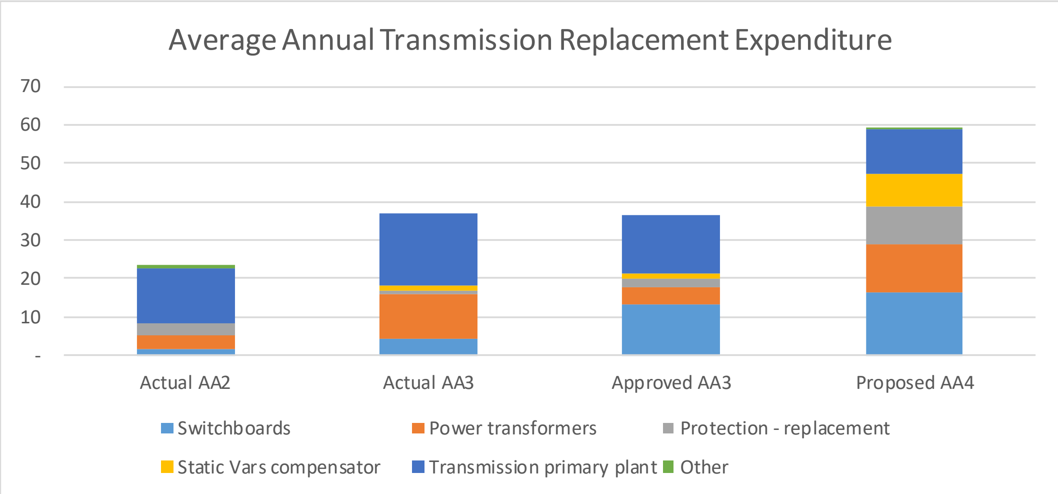
Conclusion

While we have no view on the correct accounting treatment of decommissioning costs where a site is no longer required, we do not think that decommissioning provisions meet NFIT requirements for inclusion in the RAB. In our view, this treatment is not permitted by the Code and, should the Authority decide that it is appropriate for these costs to be capitalised, as we understand it they will be fully recovered without the inclusion of any decommissioning provision.

3.1.2 Transmission Asset Replacement and Renewal Expenditure

Figure 3.3 disaggregates Western Power's transmission replacement capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure. Western Power's transmission replacement and renewal capex was around $37 million per year in AA3, which was approximately 20% of its total transmission capex.

Figure 3.3: Actual, Approved and Proposed Transmission Replacement Expenditure ($ million, real 2017)



The ongoing increase in asset replacement capex is to be expected, given Western Power's aging transmission network. In reality, Figure 3.3 understates expenditure on asset replacement as pole and cross-arm replacements are categorised as regulatory compliance and, as we have already noted, new assets installed to implement replacement driven network optimisations are categorised as capacity expansion when the new assets are not direct replacements. Furthermore, much of the expenditure in the regulatory compliance and SCADA and communications expenditure categories involve the replacement or renewal of existing assets.

3.1.2.1 Muja Power Transformer Replacements

While the total AA3 spend on transmission asset replacement is in line with the forecast, the amount spent on power transformer replacement is about 160% higher than forecast. Western Power has noted that, in addition to the transformers committed for replacement during AA3, there were unexpected mid-life transformer failures, resulting in the reallocation of expenditure intended for switchboard replacement. These included the two bus tie transformer failures at the Muja power station, which are discussed in Appendix A3.

BTT1 at Muja failed unexpectedly in September 2012 and BTT2 subsequently failed, also unexpectedly, in February 2014, The BTT2 failure, which occurred before the replacement for the failed BBT1 transformer could be put into service, caused network constraints that required available generation to be dispatched out of merit for some months, at a significant cost to the wholesale electricity market.

Following the Muja transformer failures, the Authority made management of Western Power's transformer fleet an area of special focus for the independent asset management reviews undertaken in 2014 and 2017 in accordance with the requirements of Western Power's electricity transmission and distribution licences. The reviewers found that the transformer inspection and maintenance practices in place prior to the failures was consistent with good electricity industry practice. The reviewers also examined the maintenance records for all three Muja bus tie transformers in the period leading up to the failures and found no untoward condition indicators. They commented that, if anything, the maintenance records showed that the BBT3 transformer, which remained in service, was the one more likely to fail. We note that Western Power rewrote its power transformer management strategy in July 2016, which is not to suggest that we think its old strategy written in 2011 was fundamentally flawed.

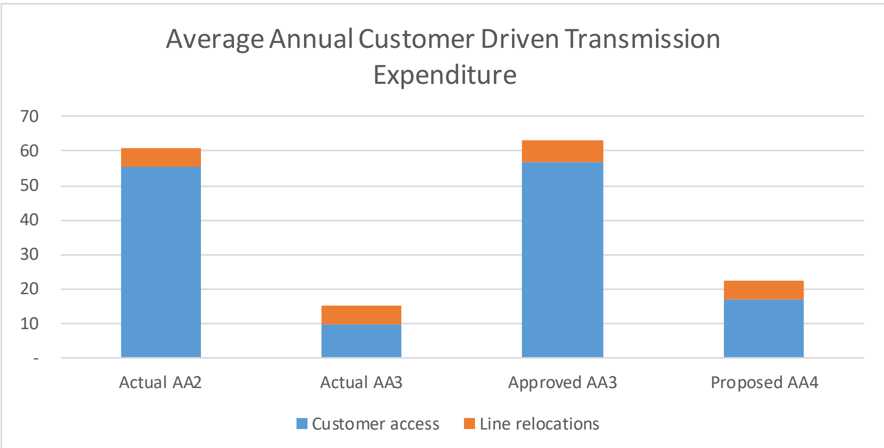
As discussed in Appendix A3, we consider Western Power's responses to the two Muja transformer failures were appropriate and timely, and note that Western Power could not be held responsible for the manufacturing problems that prevented the BTT1 replacement transformer being put into service before BTT2 failed. We also consider that, in the circumstances, the decision to order a second 330/132 KV transformer as a strategic spare and contingency if required was appropriate.

Western Power has advised that it received insurance payouts in respect of both transformer failures and these recoveries were treated as revenue from asset disposals rather than as capital contributions to the cost of replacing the units. It stated that including these amounts as asset disposal revenue ensures that they are not passed to the RAB. We have not considered whether this accounting treatment is appropriate.

3.1.3 Customer Driven Transmission Capital Expenditure

Figure 3.4 disaggregates Western Power's customer driven transmission capex into its two major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure. Western Power's customer driven transmission capex was around $15 million per year in AA3, which was approximately 8% of its total transmission capex.

Figure 3.4: Actual, Approved and Proposed Transmission Customer Driven Expenditure ($ million, real 2017)



Expenditure on assets to allow new customers to connect to the transmission network during AA3, totalled $48.90 million (real 2017), 83% lower than the forecast $283.41 million. Due to the economic conditions some mining projects have not proceeded. Other reasons included the introduction of the revised AQP, which caused delays in progressing some projects. The introduction of the electricity market reform program has also reduced the expenditure requirement, as customers adopted a wait and see approach before committing expenditure on new projects. The $48.90 million total capex was offset by customer contributions of $17.69 million (36%), leaving a net $31.21 million to be added to the opening AA4 RAB. This capital contributions recovery amount is broadly consistent with AA2, when approximately 44% of customer driven transmission capex was recovered through capital contributions.

Major customer access projects included the new Medical Centre substation and the project list includes the undergrounding of three spans of the 132 kV Manning to Osborne Park transmission line. These two projects are discussed in Sections 3.1.3.1 and 3.1.3.2 below.

Line relocation expenditure during AA3 totalled $27.52 million, 16% lower than forecast, and according to Western Power was fully funded by capital contributions of $29.19 million. The fact that capital contributions are higher than the actual spend is attributed to timing differences between the expenditure being incurred and the capital contributions being recognised in the regulatory financial statements.

3.1.3.1 Manning – Osborne Park Transmission Line Undergrounding

This project involved the undergrounding in Ewen St, Woodlands of three spans of the 132 kV Manning to Osborne Park transmission line. This section of the line had been relocated in December 2010 to enable a commercial development. The relocation, which was paid for in full by the developer, moved the line 30 metres closer to houses than the original line.

Following the relocation, residents raised concerns about the visual impact of the new steel poles, the potential health impact caused by the proximity of the line to houses, the potential reduction in property values, the closeness of the line to a child care centre and ineffective community consultation. The issue became politicised with two letters being sent to the Minister for Energy and one to the office of the Premier. In response to continuing community concerns, Western Power acknowledged that the community consultation on the original line relocation was insufficient and in December 2012 committed to undergrounding the three spans concerned.

The business case for the undergrounding acknowledged that the cost of the undergrounding did not meet NFIT requirements and would therefore not be able to be recovered through regulated revenue. We agree with this assessment. Western Power has subsequently advised that it erred in including the cost of this project in its proposed AA4 opening capital base. The opening AA4 RAB should be reduced by $2.13 million (real 2017) to correct for this error.

We further noted that this project was included as a customer access rather than a line relocation activity. The reason for this is not clear but it could be that line relocation projects should be fully funded by the external party requesting the relocation.

3.1.3.2 Medical Centre Zone Substation

This project is discussed in Appendix A2. We consider the capital expenditure during AA3 to be efficient and to meet NFIT requirements subject to the following provisos:

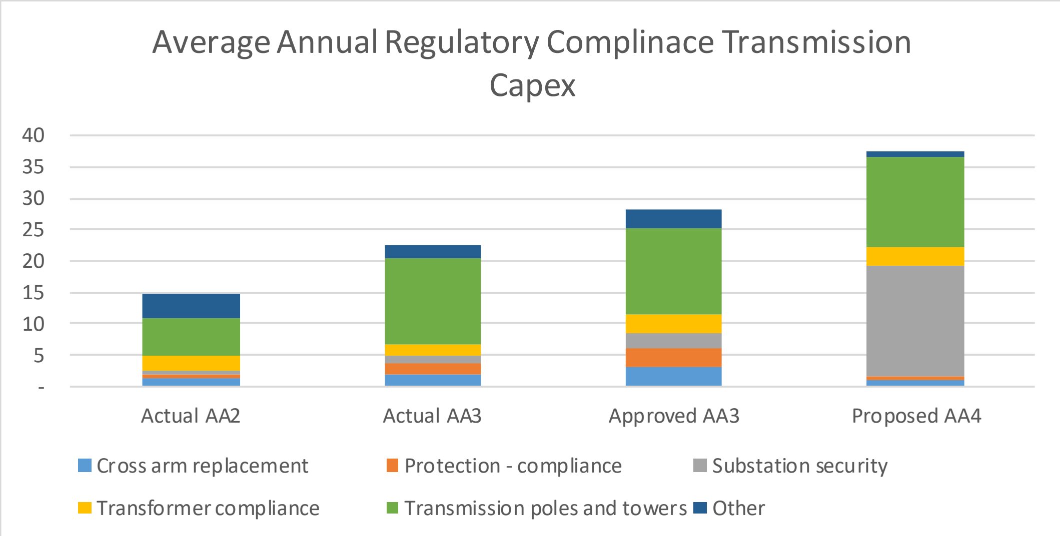
- Capital contributions do not meet NFIT requirements. Western Power has advised that it received a $0.7 million bring-forward customer contribution for this project, notwithstanding the Authority's finding in its NFIT pre-approval determination that no bring-forward contribution was warranted as construction in 2014 could be justified as meeting NFIT requirements given the poor condition of the assets that the substation would replace

- While the decommissioning of the University substation was treated as non-recurring opex in the business case, Western Power is now planning to capitalise this expenditure and has included the decommissioning costs in its AA4 capex forecast. While we are not accountants, it is not clear to us that Western Power should be capitalising decommissioning costs on a site it no longer requires. This is discussed further in Section 3.1.1.5.

3.1.4 Transmission Regulatory Compliance Expenditure

Figure 3.5 disaggregates Western Power's regulatory compliance transmission capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure. Western Power's regulatory compliance transmission capex was around $21 million per year in AA3, which was approximately 11% of its total transmission capex. Approximately two-thirds of this expenditure ($13.92 million per year) was on the replacement of transmission towers and poles.

Figure 3.5: Actual, Approved and Proposed Transmission Regulatory Compliance Expenditure ($ million, real 2017)



As noted in Section 3.1.2, much of the expenditure in this category involves the replacement or renewal of existing assets. We asked Western Power to clarify the distinction between regulatory compliance and asset replacement and why transmission pole, tower and cross arm replacements were categorised as regulatory compliance rather than asset replacement and renewal. It advised that this categorisation had been in place since AA2.

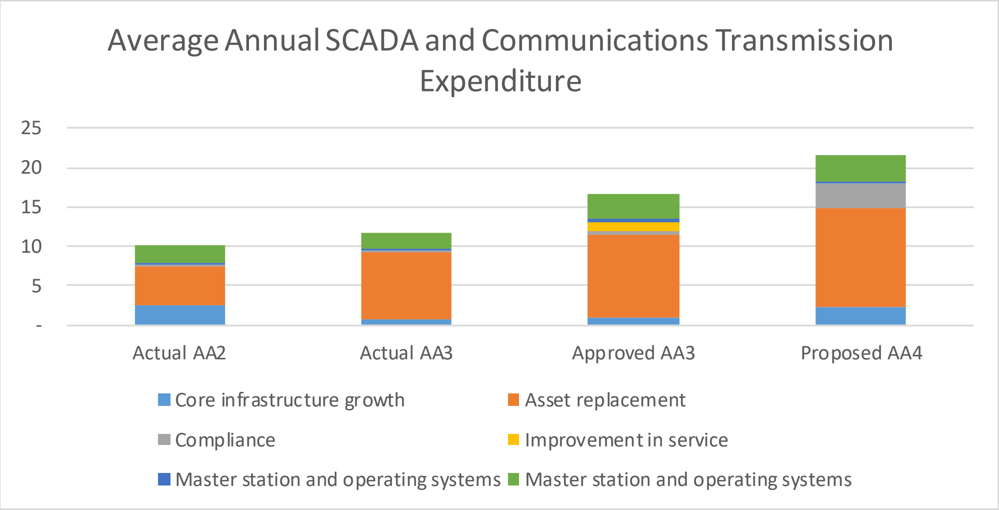
3.1.5 Reliability Driven Expenditure

Reliability driven expenditure during AA3 averaged $0.59 million per year compared to an annual average of $1.22 million in AA2. This expenditure involved the procurement and installation of additional power quality monitoring equipment. Western Power is no longer focusing expenditure on reliability improvement, as its current objective is to maintain, rather than improve on, its current level of reliability.

3.1.6 SCADA and Communications Expenditure

Figure 3.6 disaggregates Western Power's SCADA and communications transmission capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and Western Power's proposed AA4 expenditure. Western Power's SCADA and communications transmission capex was $11.68 million per year in AA3, which was approximately 6% of its total transmission capex. Almost 75% of this expenditure ($8.64 million per year) was on the replacement of SCADA and communications assets.

Figure 3.6: Actual, Approved and Proposed Transmission Regulatory Compliance Expenditure ($ million, real 2017)



4. DISTRIBUTION CAPITAL EXPENDITURE

Table 4.1 and Figure 4.1 disaggregate Western Power's distribution capex into its major expenditure categories and compare its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA1 and AA2 expenditure and Western Power's proposed AA4 expenditure.

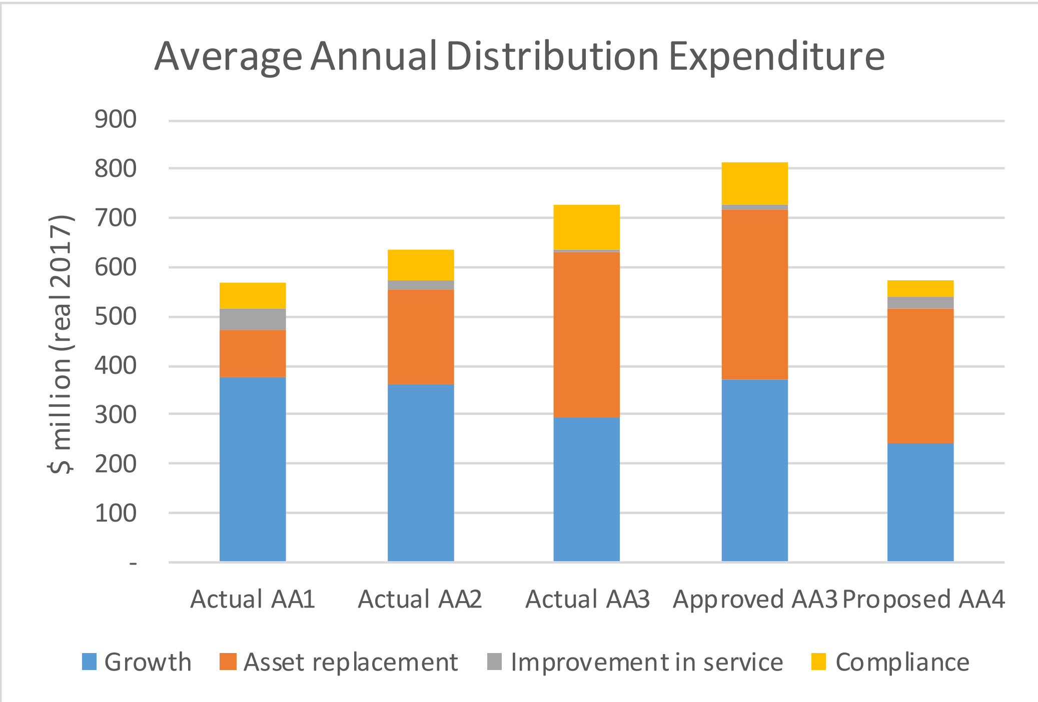
The analysis in this section uses the expenditure categories that Western Power uses in its regulatory model. Hence growth expenditure includes expenditure on expanding the capacity of the existing network to cater for incremental growth, all customer driven expenditure (including non-growth expenditure such as line relocations) and the value of gifted assets. Asset replacement and renewal expenditure includes not only like-for-like replacements and wood pole management, but also the State Underground Power Program, smart grid, and metering expenditure. Improvement in service includes reliability driven expenditure, and SCADA and Communications.

Table 4.1.: Total Average Annual Distribution Capital Expenditure ($ million, real 2017)

	Actual AA1	Actual AA2	Actual AA3	Approved AA3	Proposed AA4
Growth	376.65	360.56	296.85	369.59	241.44
Asset replacement	94.67	194.05	335.01	350.04	275.12
Improvement in service	46.25	16.56	4.92	7.15	22.66
Compliance	51.34	64.73	92.10	88.71	36.25
Total	**568.91**	**635.91**	**728.88**	**815.49**	**575.47**

Note: Expenditure includes gifted assets and capital contributions

Figure 4.1: Actual, Approved and Proposed Distribution Capex ($ million, real 2017)

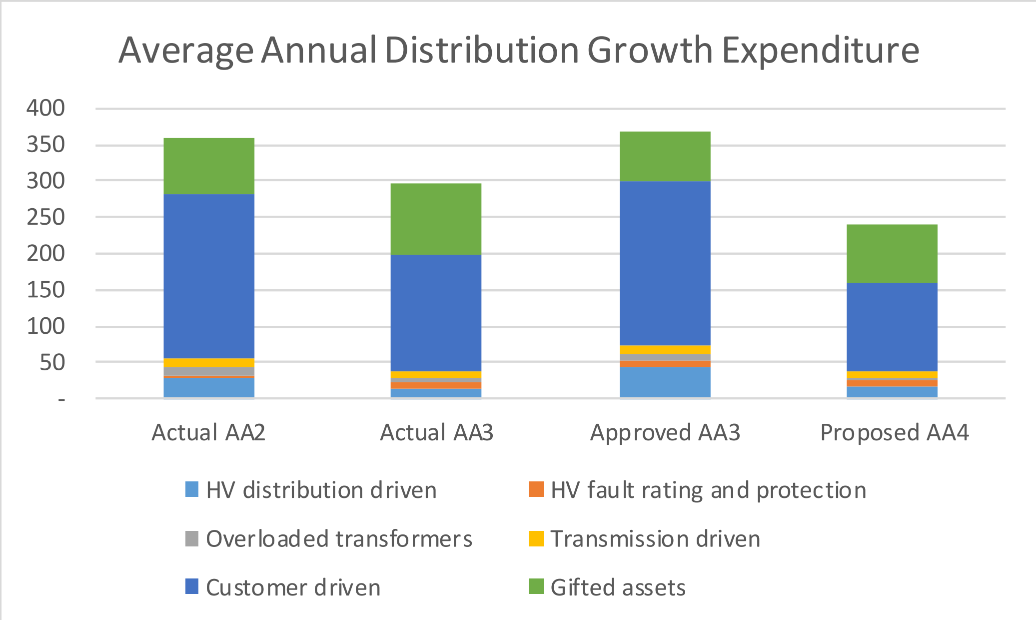


Western Power's distribution capex has progressively increased from approximately $570 million (real 2017) per year in AA1 to $730 million per year in AA3 and currently accounts for more than 70% of its total capex. The two major expenditure categories are growth and asset replacement, which together account for more than 85% of capex on the distribution network. However, growth related capex is gradually reducing, and asset replacement capex is increasing; trends driven by a continuing decline in the rate of growth in electricity demand and stakeholder concerns over the safety and reliability of the aging network.

4.1 GROWTH RELATED DISTRIBUTION CAPITAL EXPENDITURE

Figure 4.2 disaggregates Western Power's growth-related distribution capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding approved AA3 forecast expenditure as well as the actual AA2 expenditure and proposed AA4 expenditure.

Figure 4.2: Actual, Approved and Proposed Growth-Related Distribution Capex ($ million, real 2017)



Growth related distribution capex is predominately customer driven and during AA3 amounted to $999.68 million (real 2017), excluding gifted assets. This was 33% lower than the AA3 forecast due primarily to the decline in the rate of demand growth. This decline can be attributed to the depressed state economy, a substantial increase in behind-the-meter solar generation and the impact of energy efficiency initiatives.

Of the total growth-related distribution capex during AA3, $817.99 million or 82% is customer driven and includes the installation of connection assets (which are fully funded by the customer), and extending or reinforcing the distribution network to connect new customers. Customer driven shared network augmentations are partly funded by capital contributions, which in principle are calculated by subtracting the network augmentation amount that satisfies the incremental revenue test from the total cost of the customer driven augmentation. However, the access arrangement currently provides for a distribution headworks scheme and a distribution low voltage connection headworks scheme, where capital contributions are calculated on a levelized basis rather than independently calculated for each project.

During AA3 capital contributions totalled $407.44 million. To calculate the NFIT component, Western Power has simply subtracted the capital contributions from its total AA3 expenditure leaving a balance of $410.55 million to be included in the AA4 opening RAB. This approach assumes that all customer driven distribution capex funded by Western Power satisfies NFIT, but there is some evidence that this might not be the case. Western Power stated in paragraph 1132 of its AAI that:

> *The outstanding costs rarely meet the NFIT (due to being outside natural load growth scenarios) and, given the lack of growth in regional areas, the upgrade costs are*

rarely recovered from the actual customer or customers served. Instead, these costs are being recovered from all customers (where the costs meet NFIT) or borne by Western Power directly (where the costs do not meet NFIT).

Western Power has advised that it considers that the application of NFIT was individually applied for distribution headworks scheme projects during AA3. Where a distribution headworks scheme project did not meet NFIT (either in part or in full), it reverted to the full cost minus NFIT approach to charging capital contributions. It also noted that a portion of the 1,186 distribution headworks scheme projects within the AA3 period did not progress beyond the design stage. As such, Western Power incurred design expenses but did not receive any contribution from the customer. It has recently initiated a design fee for customer-driven projects to ensure such fees are recovered directly from enquiring customers.

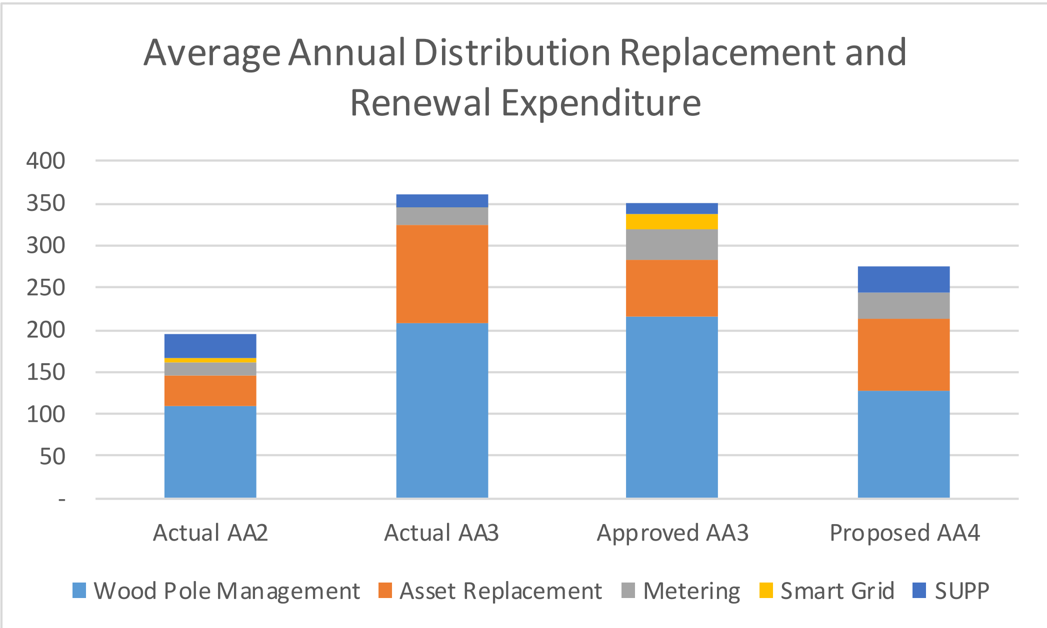
We suspect that some customer driven distribution capex during AA3 would not meet NFIT requirements. However Western Power's internal systems do not have the capacity to disaggregate this expenditure to the extent necessary to make a reliable estimate of any NFIT non-compliant amount. We acknowledge that Western Power is moving to address the issues raised, in discontinuing the distribution headworks scheme in AA4 and in recovering design fees directly from enquiring customers. We think that the total expenditure in this category that is not fully NFIT compliant is likely to be small compared to the total category expenditure and are therefore not proposing any adjustment to the amount determined by Western Power to be NFIT compliant.

The other major growth-related category is gifted assets, which are not subject to NFIT as they are not included in the RAB.

4.2 ASSET REPLACEMENT AND RENEWAL

Figure 4.3 disaggregates Western Power's distribution asset replacement and renewal capex into its major expenditure categories and compares its actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure.

Figure 4.3: Actual, Approved and Proposed Replacement and Renewal Distribution Capex ($ million, real 2017)



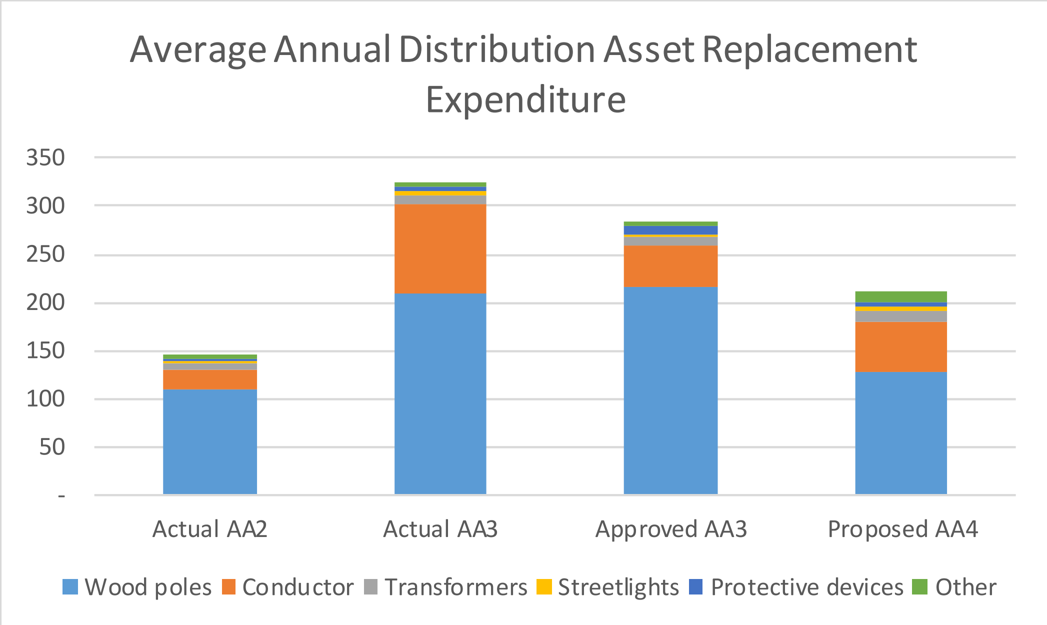
Wood pole replacement and renewal, which includes pole reinforcement, while down marginally on the AA3 forecast, accounted for 58% of Western Power's distribution replacement and renewal expenditure during AA3. The smart grid program, which is included for completeness, has now been discontinued. As the smart grid expenditure during AA3 was not material this is not considered further.

4.2.1 Asset Replacement Expenditure

In accordance with a requirement of the Authority in its AA3 final decision, Western Power has treated wood pole management as a stand-alone asset category. However, we have considered it an asset replacement expenditure for this analysis, since the substantive difference between it and other asset replacement expenditure sub-categories is one of scale.

Figure 4.4 disaggregates this distribution asset replacement expenditure into its major asset categories and compares the actual AA3 expenditure in each category with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure.

Figure 4.4: Actual, Approved and Proposed Asset Replacement and Renewal Distribution Capex ($ million, real 2017)



Taken together, wood pole and conductor replacements comprised 91% of Western Power's expenditure on the replacement and renewal of distribution assets and 32% of Western Power's total distribution network capex. These are discussed in Section 4.2.1.1 and 4.2.1.2 below.

4.2.1.1 Distribution Wood Pole Replacement

Western Power's distribution wood pole replacement program is discussed in detail in Appendix A4. This expenditure was significantly higher in the first years of AA3 because poles were replaced that in hindsight were still in satisfactory condition and were not overloaded. At the time Western Power was under intense pressure from both Energy*Safety* and the Government to reduce the public safety risk of its wood pole fleet and to comply with the requirements of the Energy*Safety* Order. It now uses a much-improved wood pole management strategy, which we understand analyses the need to replace or reinforce each individual pole using highly granular data, that has been developed over several years and required a significant investment in research and development. It was not available to Western Power until the middle of the AA3 period.

Over the whole of AA3, Western Power has replaced 15% less poles and reinforced 29% less poles than forecast at the beginning of the period. Notwithstanding this, Energy*Safety* has confirmed that Western Power has fully complied with the intent of its 2009 Order and has also endorsed its current wood pole management strategy as an appropriate basis for managing its wood pole fleet going forward.

While Western Power was able to deliver its wood pole reinforcements at an average unit rate 10% lower than the AA3 forecast its average pole replacement unit rate across the period was 32% higher than forecast. It has provided explanations for this increase that we consider satisfactory.

We therefore consider that all distribution wood pole expenditure over the AA3 period meets NFIT requirements and should be included in the AA4 opening RAB. This expenditure amounted to $1,041.8 million[7] (real 2017) compared to a forecast of $1,085.1 million (real, 2017). As distribution wood pole management was subject to the investment adjustment mechanism, a reduction of $43.3 million (real, 2017) is indicated.

4.2.1.2 Distribution Conductor Replacement

This program is discussed in Appendix A5. Approximately 40% of the 69,000 circuit-km of distribution conductor on Western Power's network is now more than 40 years old. As conductor failures pose a public safety risk in that they can start bush fires and potentially cause electric shocks, this age profile indicates that Western Power is prudent in proactively undertaking a conductor replacement program, to avoid a repeat of the situation it found itself in some years ago with its wood pole fleet.

The total circuit-km of conductor replaced during the AA3 period was 88% of the circuit length forecast at the start of the period, but the cost of the program was more than double the approved forecast. While this was due to several factors, the decision by Western Power to focus on reducing the potential consequences of a conductor failure when prioritising projects to be included in the program, rather than on simply reducing the number of failures, was a significant driver of the higher unit rates since it meant that a much larger proportion of the program involved the replacement of conductors on three phase circuits in populated areas and in extreme and high bushfire risk zones. As a result, the unit rates assumed at the time of the AA3 review ceased to be relevant. We consider circuit-km a crude normaliser for assessing unit rates of conductor replacement because of the wide spectrum of rates involved – the cost of replacing the conductor on a three-phase circuit in a built-up area is many times the cost of replacing the conductor on a similar length of single phase circuit in a sparsely populated rural area. We are satisfied that Western Power took appropriate steps to minimise the cost of the work undertaken under this program.

We note that, as a result of a business transformation initiative, Western Power is now using conductor sampling and metallurgical testing to assess conductor condition more accurately and therefore giving condition a higher weighting when assessing projects to be included in the program. This is a worthwhile initiative.

While the total expenditure on this program was more than twice the approved AA3 forecast, we consider that it fully meets NFIT requirements and should all be included in the opening AA4 RAB.

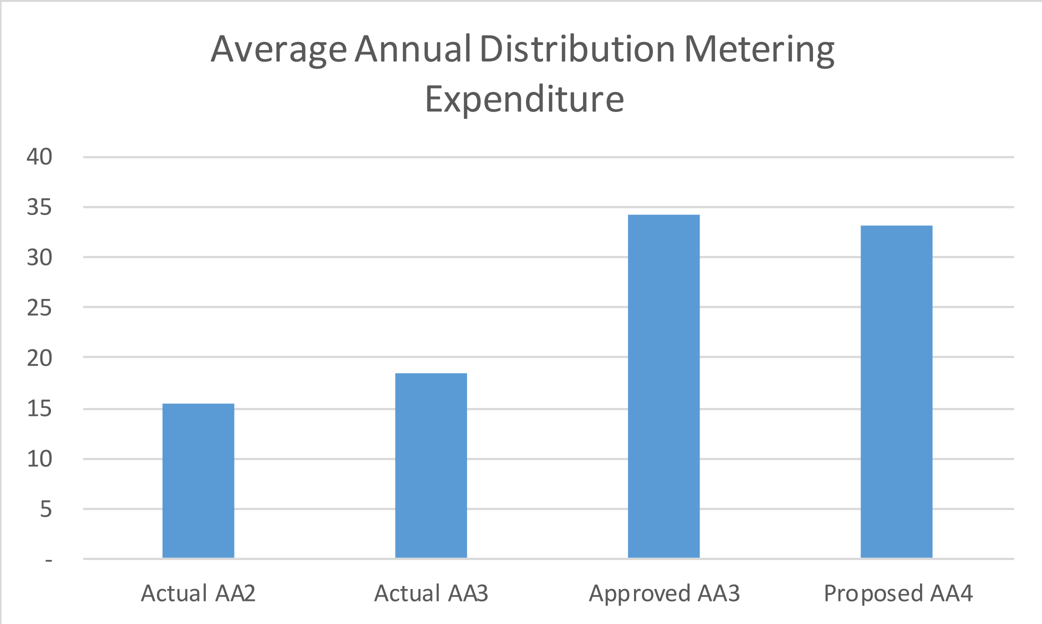
4.2.2 Metering

Figure 4.5 compares Western Power's actual AA3 distribution metering capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure.

---

7 This is higher than the $1,036.7 million shown in Table A4.1. This is because the actual AA3 costs shown in the tables were taken from Western Power's compliance summaries and differ from the numbers in its revenue model. While the difference is not material Western Power has confirmed that the expenditure of $1,041.8 million used in its revenue model is accurate.

Figure 4.5: Actual, Approved and Proposed Distribution Metering Capex ($ million, real 2017)



The actual AA3 expenditure was lower than forecast primarily because the forecast included a provision for the replacement of 280,000 three phase meters that were deemed non-compliant under the Electricity (Supply Standards and System Safety) Regulations 2001. However, the gazettal of the Electricity (Network Safety) Regulations 2015 relaxed this requirement and only a subset of 54,000 meters needed to be replaced. This work was undertaken during the final two years of AA3 at a cost of $25.52 million.

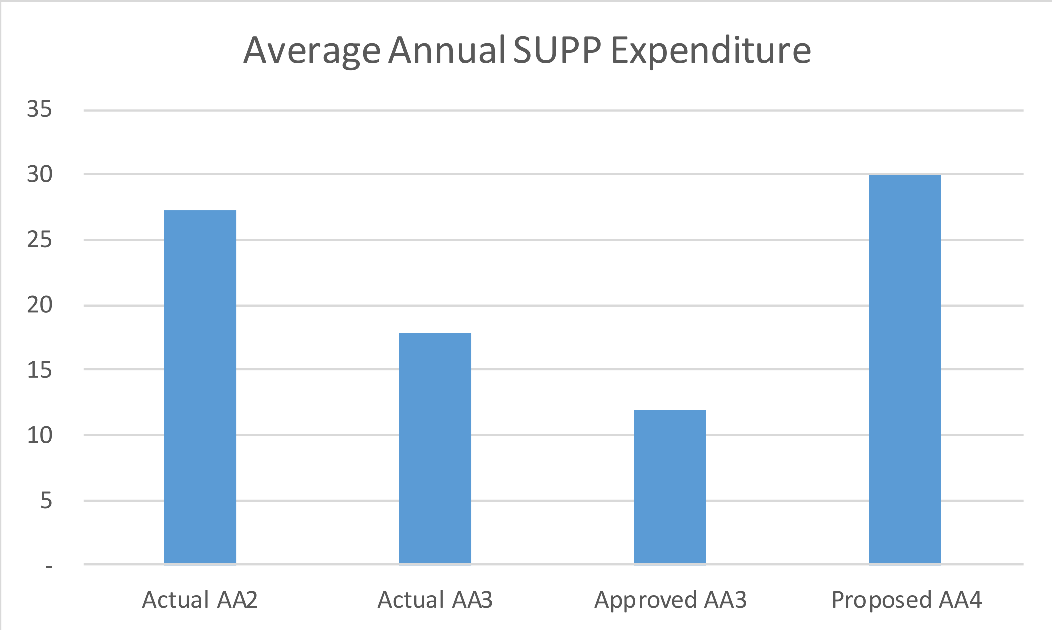
Expenditure of $2.28 million that was not provided for in the AA3 forecast was required after Telstra decided to shut down its 2G network. Western Power, like other metering providers, relies on the cellular network to provide the communications links needed for the remote reading of interval meters used by contestable customers.

The remaining AA3 expenditure of $65.10 million was used for the provision and installation of new and replacement low voltage meters.

4.2.3 State Underground Power Program

Figure 4.6 compares Western Power's actual AA3 SUPP capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and Western Power's proposed AA4 expenditure.

Figure 4.6: Actual, Approved, and Proposed SUPP Capex ($ million, real 2017)



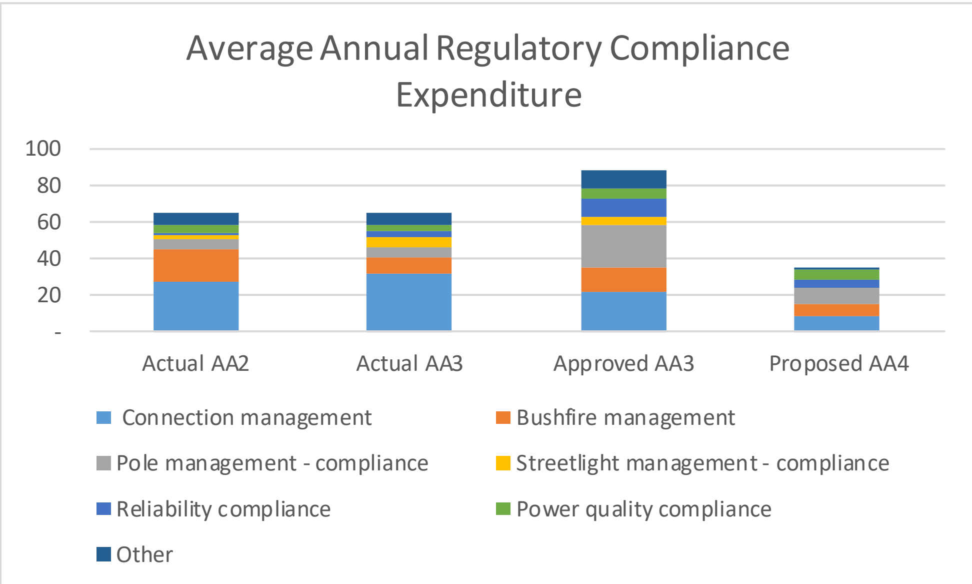
Note: Includes State Government and local council contributions.

The SUPP is a partnership between the State Government, local councils, and Western Power, with funding for the program shared between the three parties. Western Power is responsible for implementing projects approved under the program. It's contribution to the cost of the program is justified by the lower maintenance costs of underground reticulation compared to the cost of maintaining overhead assets to provide the same level of service. During AA3, Western Power's SUPP expenditure was $83.90 million, of which $47.72 million was funded through capital contributions from the other program partners. Only Western Power's contribution to the program has been included in its proposed AA4 opening RAB.

4.3 REGULATORY COMPLIANCE CAPITAL EXPENDITURE

Figure 4.7 compares Western Power's actual AA3 regulatory compliance capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and Western Power's proposed AA4 expenditure.

Figure 4.7: Actual, Approved and Proposed Regulatory Compliance Capex ($ million, real 2017)



Regulatory compliance expenditure ensures that distribution network assets maintain compliance with legal and regulatory requirements. The major expenditures in this category during AA3 are discussed briefly below.

- Connection management, which describes the replacement or renewal of overhead customer service connections (OCSC) due to low ground clearance or for other safety reasons. Western Power's program to remedy unsafe service connections was completed in 2015/16. Total expenditure on this program during AA3 was $162.05 million, which was 50% of Western Power's total regulatory compliance expenditure over the period.

  The program was initiated following two fatalities in 2003, for which the root cause was the insulation failure of OCSC preformed steel helical type service terminations. Western Power made a commitment to Energy*Safety* in April 2005 to address these safety issues. This commitment and Western Power's overarching safety objective drove substantial remediation and rectification works during AA2 and AA3.

- The bushfire management program, which is designed to prevent the clashing of conductors in high risk bushfire areas to reduce the risk of sparks initiating a bushfire. Expenditure on this program was $39.13 million over the AA3 period, which was 12% of the regulatory compliance spend. This was 44% lower than the approved AA3 forecast, after Western Power implemented strategy changes leading to a more efficient targeting of clashing conductor risk. Almost 78% of this expenditure was incurred over the first two years of AA3.

- Expenditure on pole management compliance and pole top management during AA3 was $40.49 million or 12% of Western Power's regulatory compliance expenditure over the period.

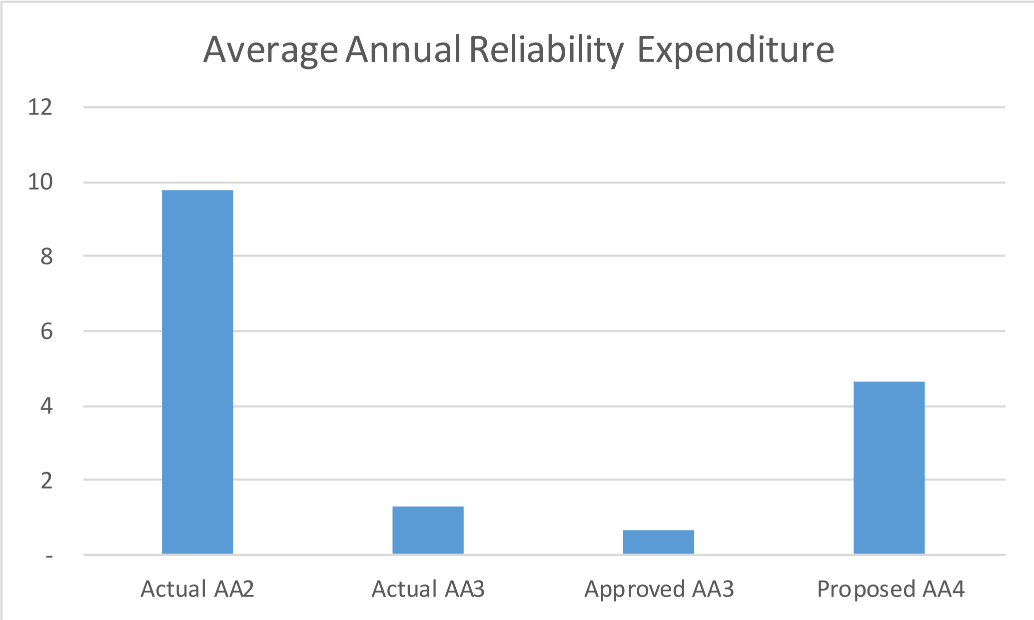
Regulatory compliance expenditure reduced over the period, from $110.9 million during 2012/13 to $13.77 million in 2016/17. Western Power advises that this was due to the completion of safety programs including the replacement of all known streetlight switch wire and at-risk overhead customer service connections. It has also introduced zonal treatment instead of standalone programs for some asset categories, which has resulted in a reduction of replacement volumes as only known defects in each zone were addressed. Finally, it has identified and adopted alternative risk-based treatment options to address some compliance issues.

4.4 IMPROVEMENT IN SERVICE EXPENDITURE

4.4.1 Reliability Driven

Reliability driven expenditure relates to projects that involve the use of new technologies. Figure 4.8 shows Western Power's average annual expenditure in this category. Key projects in this category during AA3 were the Perenjori battery energy storage system and the Kalbarri microgrid project. The Perenjori project is discussed in Section 4.4.1.1 below while the Kalbarri project is ongoing and will continue into AA4.

Figure 4.8: Actual, Approved and Proposed Reliability Capex ($ million, real 2017



4.4.1.1 Perenjori Battery Energy Storage System

This project, which is discussed in Appendix A6, involved the installation of a battery energy storage system (BESS) to improve the reliability of supply to users in the town of Perenjori, which is located on the edge of the distribution system at the end of the Morawa feeder supplied from the Three Springs zone substation. In the event of a loss of supply due to a fault on the feeder, the Perenjori town will be disconnected from the grid and supplied by the energy stored in the utility sized battery in less than 150 milliseconds.

Western Power has advised that some expenditure on the Perenjori project does not meet NFIT requirements and should therefore not be included in the RAB. This would result in a reduction of $1.78 million (real 2017) in the AA4 opening RAB. This conclusion is based on a perception that the current regulatory framework does not support small scale research and development initiatives unless that can be shown to be economic.

Notwithstanding this, we reviewed the business case to make our own assessment of NFIT compliance. The primary objective of the project was to trial the use of utility scale BESS as an alternative means of providing a reliable power supply and improvement in reliability to users in Perenjori town was secondary to this. We therefore question the relevance of much of the economic analysis since this analysis suggested that reliability improvement was the primary benefit.

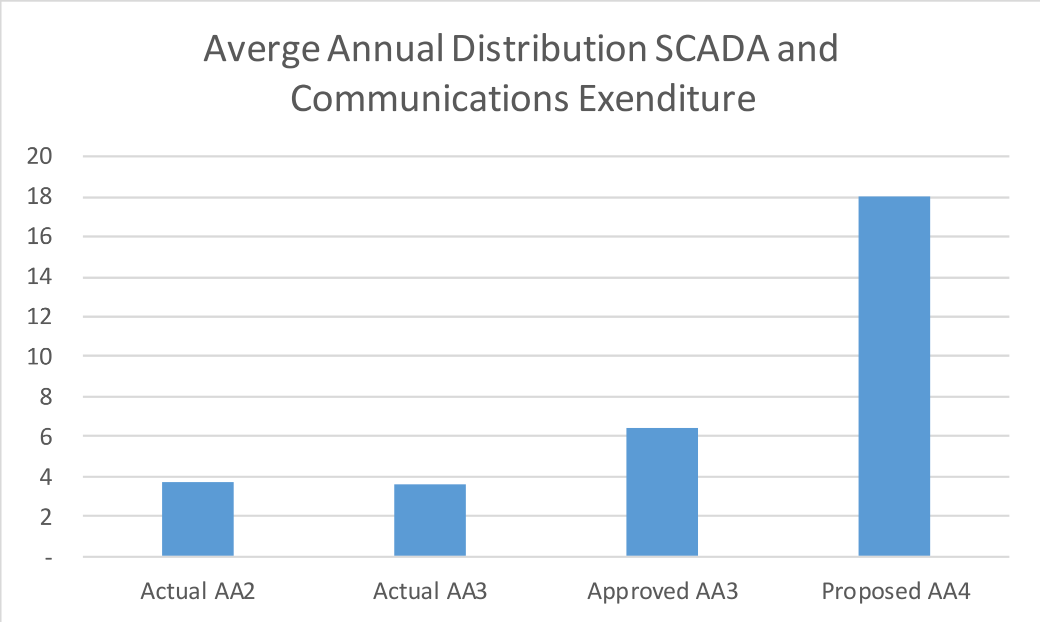
Our NFIT compliance assessment has been influenced by our view that a regulator should not put impediments in the way of a distribution business undertaking appropriately developed, *small scale* research and development into the likely impacts of new and disruptive technologies on electricity distribution. We note from the public submissions on Western Power's AA4 access arrangement information that many stakeholders would agree with this, and that the primary concerns in the regulatory scrutiny of initiatives involving the use of new and disruptive technologies relate not to the use of the technologies but to the scale of the rollout and the magnitude of the cost to users if the forecast benefits do not materialise.

In our view all capital investment on this project meets NFIT requirements in that it maintains the reliability of the covered network and is of a size and scale appropriate to a research and development project. However, the business case indicates that the project may attract a $1.89 million research and development tax incentive. We think any such tax incentive should be treated in the regulatory accounts as a capital contribution to the project rather than a windfall gain to Western Power.

4.4.2 SCADA and Communications

Figure 4.9 compares Western Power's actual AA3 distribution SCADA and communications capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure. Expenditure was comparable to that in AA2, but 30% below the approved AA3 amount and well below the amount proposed for AA4. Western Power has stated that, while critical work has been undertaken, resources were redirected to other projects and business transformation initiatives, so that some work in this area has been deferred.

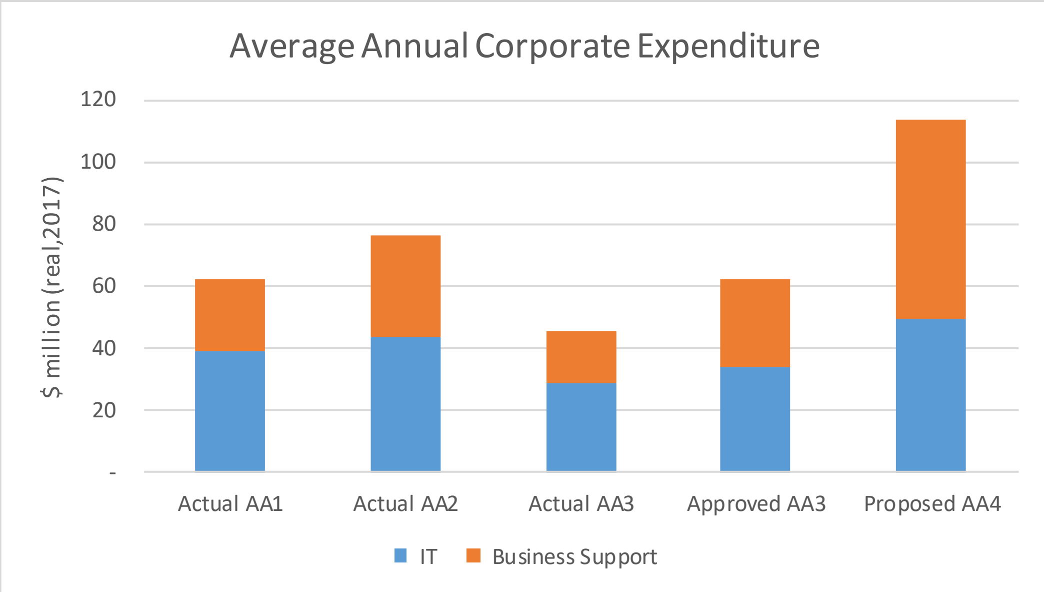
Figure 4.9: Actual, Approved, and Proposed SCADA and Communications Capex ($ million, real 2017



5. CORPORATE CAPITAL EXPENDITURE

Corporate capex includes IT and business support expenditure. Western Power's regulatory model also classifies equity raising costs incurred during AA3 as corporate capital expenditure, but these are not considered in this report. Figure 5.1 compares Western Power's total AA3 business support capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure.

Figure 5.1: Actual, Approved and Proposed Corporate Expenditure ($ million, real 2017)

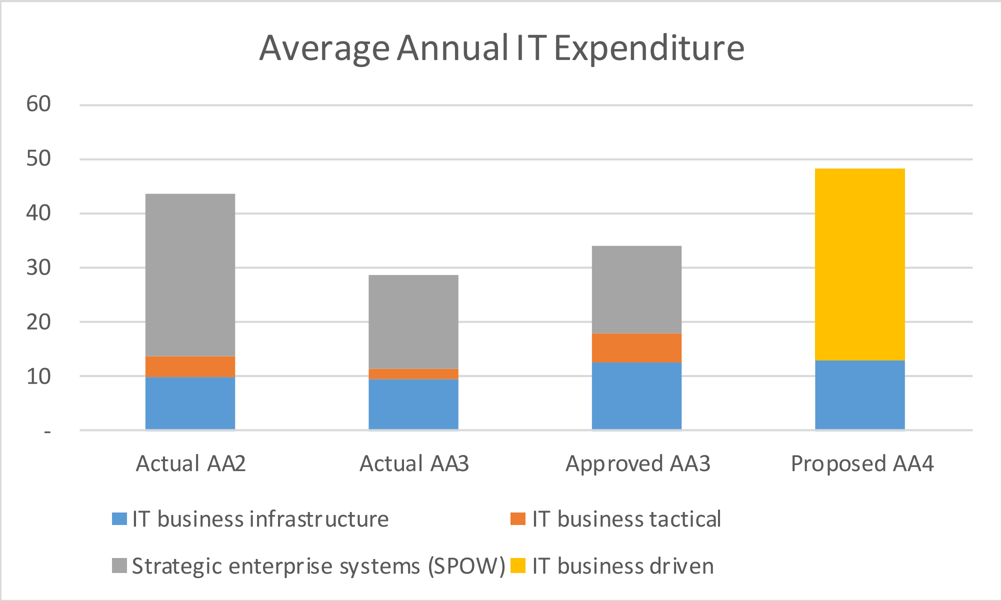


Western Power's corporate capex was relatively low during AA3, particularly in the business support area, where expenditure was primarily related to the refurbishment of the head office building in Wellington Street. In total, corporate capex represented less than 5% of Western Power's total AA3 capex.

5.1 IT CAPITAL EXPENDITURE

Figure 5.2 compares Western Power's actual IT capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 expenditure and proposed AA4 expenditure. AA3 expenditure was lower than forecast, notwithstanding the introduction of the business transformation program and the aggressive approach Western Power has taken to improving its asset management efficiency.

Figure 5.2: Actual, Approved and Proposed IT Expenditure ($ million, real 2017)



5.1.1 Mobile Workforce Solutions and Field Mobility Services

Our review of the extent of NFIT compliance of Western Power's AA2 expenditure found that IT was at the time the area where Western Power had most difficulty delivering project outcomes within budget. In our final report we noted, in respect of the Mobile Workforce Solutions (MWS) project, which has continued into AA3, that[8]:

> *The problems that have beset this [MWS] 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.*

To assess whether Western Power's management of IT project had improved since AA2 we reviewed the project closing report for the MWS project and documents related to the implementation of the Field Mobility Services (FMS) project.

Western Power commenced the MWS implementation during AA2. The ultimate intent of the project was to provide a mobile solution to the field to optimise schedule and dispatch and enable real time capture of asset data. The solution was based on the Mincom Mobile platform and the initial implementation focused on distribution inspections. The implementation of the inspection component was completed in AA3 with AA3 expenditure being $2.5 million (real 2017), additional to the expenditure incurred during AA2.

Before embarking on the extension of the Mincom Mobile platform to work beyond inspections, Western Power undertook a review of the platform and options for field mobility for work types other than inspections. It concluded that the use of the Yambay solution, which was based on the mobile platform in use at Western Power for distribution outage management, was a better fit. The solution based on this Yambay platform was internally

---

8 *Technical Review of Western Power's Comments on the Economic Regulation Authority's AA3 Draft Decision;* Geoff Brown & Associates Ltd, 4 September 2012, p66.

branded "Field Mobility Solution" (FMS). FMS was implemented successfully for distribution overhead maintenance work during AA3. Today, both solutions are in use at Western Power: MWS for inspection work, including related asset data collection; and FMS for distribution field maintenance.

The FMS solution was delivered within the business case budget for $8.5 million. However, there was a significant scope reduction between Gates 2 and 3 of the development process, indicating that many of the lessons from the implementation of IT projects during AA2 had been taken on board[9]. Some of the functionality removed from the project scope, such as transmission maintenance and construction implementation, will be the subject of a separate business case.

Together, the MWS and FMS solutions are delivering real benefits to Western Power. Prior to their implementation, the updating of Western Power's asset management systems to reflect the results of asset inspections and field work was paper based and manual and it could take up to three months for asset data to be uploaded into the asset management systems. This has now been reduced to around two days.

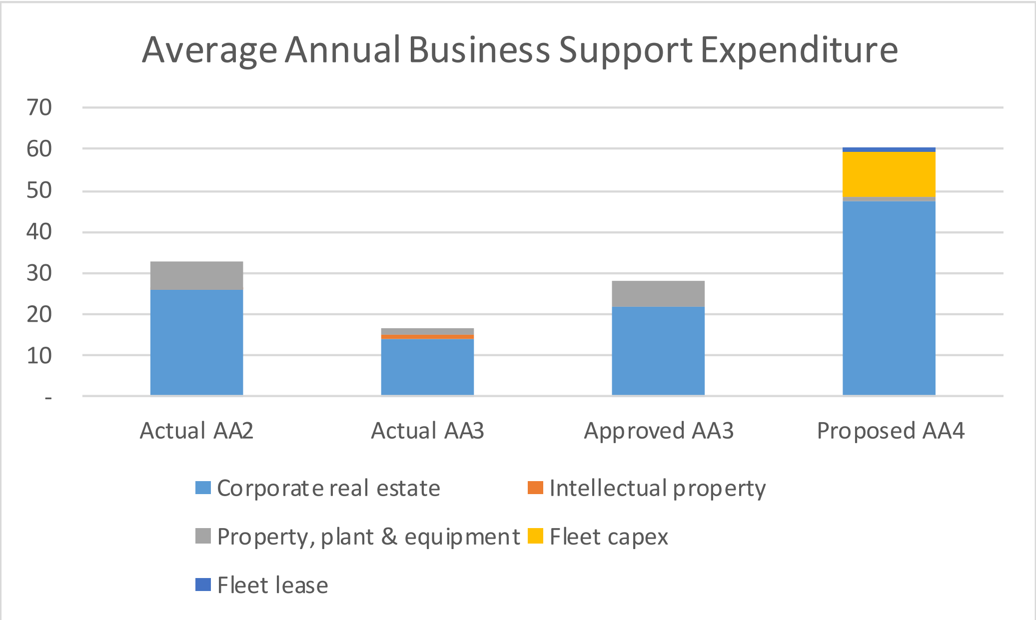
Conclusion

We conclude that over the course of AA3, there have been significant improvements in Western Power's implementation of IT systems projects and we are satisfied that all IT expenditure during AA3 meets NFIT requirements.

5.2 BUSINESS SUPPORT EXPENDITURE

Figure 5.3 compares Western Power's actual business support capex with the corresponding forecast expenditure at the AA3 regulatory reset as well as the actual AA2 and proposed AA4 expenditure.

Figure 5.3: Actual, Approved and Business Support Expenditure ($ million, real 2017)



Business support expenditure in AA3 included the following expenditure categories.

9 One of the problems in delivering IT solutions during AA2 was the management of scope creep, as stakeholders had unrealistic expectations of the benefits that IT projects might deliver, and were disinclined to accept reduced functionality.

- Corporate real estate, which includes Western Power's Wellington Street head office and its works depots from which it provides fault and other field services that are resourced internally

- Intellectual property. This is discussed in Section 5.2.3 below.

Total AA3 capex on corporate real estate was $69.7 million, of which $36.1 million was for a total of seven projects individually valued at more than $2 million. This includes expenditure on the head office refurbishment under Project Vista, which is discussed in Section 5.2.1 below and the provision for asbestos removal discussed in Section 5.2.2 below. The balance was on a range of smaller projects spread across Western Power's corporate real estate.

5.2.1 Project Vista – Head Office Refurbishment

This project is discussed in Appendix A7. Information provided for our review states that Western Power spent a total of $11.6 million (real, 2017) during AA3 on refurbishment works to the ground floor and basement, as well as levels 1 and 2 of its head office building. It also spent an additional $2.1 million (real, 2017) on refurbishment of the building lifts. This latter cost is not identified as a Project Vista cost and, while the Project Vista business case proposed an upgrade of the internal fit-out of the whole building, it does not explicitly discuss lift refurbishment.

While much of the scope of the head office refurbishment comprised essential works, the business case proposed a high-quality upgrade justified largely by unquantified benefits relating to improvements in staff productivity and morale and improvements to Western Power's reputation as a good corporate citizen. This is not to suggest that the refurbishment has not delivered savings in energy and other operational costs and Western Power has provided some evidence of this. We also note that the Authority endorsed the original scope when it approved the AA2 capex forecast.

In November 2010, the Western Power Board approved a 20% increase in the project budget. As we have not seen the business case for this increase we cannot comment on the drivers or the extent to which the Board or management reviewed the costs of the project prior to this approval. We think an independent review of the project scope and costs at this time should have been commissioned, but we do not know if this occurred. We have also seen a reference to an approved budget increase in April 2012, but we have no further information on this.

The final head office refurbishment cost as reported by Western Power exceeded the final budget by about 12% and the business case budget by 40%, but these cost overruns were masked to some extent by savings made from scope reductions in work at the metropolitan depots. While some of the budget overrun is likely to have been justified, there is also evidence that Western Power lost control over the costs of the project and this would have also contributed to the cost escalation.

The reported final cost of the project does not fully capture the internal costs of managing the project or the overheads that are normally capitalised into the cost of a project. Had these costs been included in accordance with the cost allocation rules Western Power now applies to its network projects, we conservatively estimate that the reported head office refurbishment cost would be at least $94.8 million.

The efficiency test for NFIT compliance requires that the investment does not exceed the amount that would be invested by a service provider efficiently minimising costs. We are not satisfied that the total expenditure on the head office refurbishment meets the requirements of this test but are unable to reach a conclusion on how much of this expenditure should be considered NFIT compliant.

Expenditure on Project Vista through to the end of AA2 has already been deemed to have met NFIT requirements. Any component of the total capex on this project that is considered not to meet NFIT requirements could be managed by not including some or all the AA3 Project Vista expenditure in the opening AA4 RAB.

Finally, we note that Project Vista is a legacy project that was initiated in 2008 and inherited by the current management of Western Power, who cannot be held responsible for most of the problems we have identified.

5.2.2 Asbestos Provision

The business support expenditure includes a $2.6 million (real 2017) provision for the removal of asbestos. Western Power has advised that the provision was raised for all identified remedial work necessary in relation to asbestos as per accounting standard requirements. Of the initial $2.6 million provision, $546,000 was related to works completed in the AA3 period and the remainder applied in AA4. The asbestos is located in assets across the network including the Murray St offices, depots, and substations.

While we agree that the removal of asbestos from Western Power's buildings should be capitalised, we do not believe that a provision for future expenditure meets NFIT requirements for inclusion in the RAB. This issue is discussed in Section 3.1.1.5.

5.2.3 Intellectual Property

Western Power's proposed AA4 opening RAB includes $6.70 million for "intellectual property" for work completed in preparation for transition to the national regime. It does not suggest that that the expenditure meets NFIT but argues that it is covered under the unforeseen events adjustment mechanism.

In paragraph 943 of the AAI, Western Power stated that costs that were incurred of a capital nature were capitalised (e.g. IT costs) and that costs that had potential to provide a benefit to Western Power should it transition to the National Electricity Rules (NER) in the future were also capitalised.

We sought more information from Western Power on the IT costs that were capitalised and were advised:

> *In preparation for regulation by the AER, Western Power was required to reclassify the split between the transmission and distribution network. This involved work from our IT team to extract and reclassify historic data from 2006 onwards. The cost of this work was coded against a specific work order and represented a total cost of $150,423 being labour costs. On confirmation that Western Power would no longer be transitioning to the AER, this expenditure was classified as operating expenditure.*

We do not see any justification for including any expenditure related to possible transition to the NER in the AA4 opening RAB and note that:

- intellectual property is, by definition, an intangible asset and it is not usual to include intangible assets in the *regulatory* asset base of an electricity lines business;
- the state government has indicated that it has no plans for Western Power to be regulated by the Australian Energy Regulator under the NER;

Furthermore, the code defines the *capital base* (or RAB) as the value of network assets used to provide covered services. *Network assets* are defined as:

> *the apparatus, equipment, plant, and buildings used to provide or in connection with providing covered services on the network, which assets are either connection assets or shared assets.*

This definition would appear to preclude intangible assets being included in the RAB.

6. APPLICATIONS AND QUEUING POLICY

6.1 INTRODUCTION

Under Section 5.1(g) of the Access Code, Western Power's access arrangement is required to have an Access and Queuing Policy (AQP) that sets out the way Western Power will process applications to connect loads and generators to the network and to transfer power to and from the network. Sections 5.7 to 5.9 of the Code set out certain requirements as to the nature of the policy and what the policy must contain. The AQP helps Western Power manage access applications in an orderly, transparent, and fair manner, especially when network capacity is scarce.

Appendix 2 of the Code contains a model AQP, but Section 5.9(b) clarifies that Western Power's AQP may be formulated without any reference to this model AQP and is not required to reproduce this model AQP in whole or in part.

Western Power's proposed AA4 access arrangement includes 26 proposed amendments to its current AQP as well as administrative changes to improve its application. Significant changes were made to the AQP in the AA3 access arrangement, particularly around the management of situations where a single network augmentation could be developed to meet the needs of a number of access applications if all benefitting applicants shared the cost. Western Power states that its proposed amendments have been developed in consultation with stakeholders and through its experience in implementing the AQP during AA3.

Under Section 5.11 of the Code in approving these changes the Authority must have regard to the model AQP in determining whether the revised AQP is consistent with Section 5.7 to 5.9 of the Code and the Code objective.

6.2 DEVELOPMENT OF PROPOSED AMENDMENTS

The development of the proposed amendments was guided by a two-stage customer consultation process.

The first stage was managed by GHD and involved the following steps:

Assessment of required changes

GHD assessed, reviewed, and confirmed with Western Power the required changes to the AQP. It documented these changes and produced a briefing paper to guide and inform stakeholders on the proposed changes and the consultation process.

Stakeholder engagement

This involved:

- A stakeholder forum. This was held on 3 May 2017. Attendees were provided with the briefing paper before the forum and were given the opportunity to provide input to the review process at the structured forum.
- One-on-one interviews. These were held in person and by telephone to extend the reach to stakeholders in the more remote regions of the network geography.

Written submissions

Stakeholders were provided with the opportunity to provide a written submission detailing their input to the review process.

Following this consultation process, GHD prepared a written report outlining stakeholder feedback in the issues raised in the briefing paper and identifying a number of issues not raised in the briefing paper that stakeholders considered needed to be included in the amended policy.

Following completion of the GHD report Western Power prepared a draft AQP that took into account its experience during AA3 and stakeholder feedback. It provided this draft together with a summary of changes to stakeholders and received three responses to this draft. The AQP that Western Power proposes for AA4 takes these submissions into account and Attachment 12.3 includes a commentary by Western Power on these submissions and, where applicable, gives reasons why comments made by submitters have not been incorporated into the policy. We also understand that Western Power has taken legal advice on the wording of the policy.

6.3 COMMENT

6.3.1 Stakeholder Feedback

Stakeholders, with the possible exception of Synergy, are generally positive about the policy changes proposed by Western Power. Any concerns generally relate to the detailed wording of the document and the possibility that Western Power might interpret this wording in a way that provides an unnecessary impediment to access. Given that there has not been feedback to suggest that Western Power has applied its current policy in such a manner, we suspect that most concerns expressed by submitters will not materialise in practice.

For example, Perth Energy is concerned about the requirement in clause 3.7(e) to provide all the information required by the technical rules with an access application – it comments that committing to a manufacturer, make and model early in the application stage will constrain the best investment decisions being made. Western Power does not propose to remove this requirement and considers that this information is necessary to effectively assess and process a connection application. We question whether, if both parties act in good faith as reasonable and prudent persons, there is an issue that needs to be addressed. The concern relates primarily to the connection of large generators to the network, which is a process that necessarily must take some time before Western Power, acting reasonably, is able to make an access offer that complies with clause 4.1 of the AQP[10]. The process is likely to start with pre-enquiry discussions in accordance with clause 17A, and must then include a compulsory enquiry notification under clause 18.1 before the applicant makes a formal connection application. After receiving a connection application, Western Power is likely to require system or other studies provided for in clause 20.2 before it can issue a formal access offer. We suspect that the level of detail required of an applicant will become progressively more comprehensive as the application moves through this process, but it will need to fully compliant with the technical rules by the time a formal access offer is made.

Synergy has provided a more forensic examination of the policy which considers, largely from a legal perspective, the extent to which the policy is consistent with the requirements of the Code and the extent to which the policy is worded in a way that provides an opening for Western Power to apply it in a manner that is inconsistent with the policy objectives or the intent of the Access Code.

Our view is that a policy is not a legal document and it is unrealistic to expect the wording to cover all situations in which the policy might need to be applied. It follows that, while we expect the policy wording to be clear and unambiguous, the actual wording is less important than the way in which the policy is applied in a specific situation.

To this end, we think the policy is deficient in that, while section 1 is entitled *Operation and Objectives,* there is nothing in this section on the *operation* of the policy. In our view, most of the concerns raised by submitters would be addressed if a new clause 1.2 was included in the AQP that explicitly requires Western Power to:

- act as a reasonable and prudent person in all matters relating to the processing of network access applications;

[10] This clause requires the access offer to be signed by Western Power and be in a form that can become an access contract when signed by the supplicant.

- act in a manner consistent with the objectives and requirements of the Code; and
- be transparent in its processing of access applications and avoid withholding information from applicants without good reason.

For the avoidance of doubt the policy should also state that access applicants have recourse to the disputes procedure in Chapter 10 of the Code should they consider that Western Power is applying the AQP in a manner that is inconsistent with this new clause.

6.3.2 Potential Developments during AA4

Currently the AQP has been prepared on the basis that Western Power's network will provide unconstrained access and that applicants will not be permitted to connect unless sufficient network capacity is available to allow transfer of their contracted capacity at all times. The Government has signalled its intention to move to the constrained access model used in the National Electricity Market, whereby generators and loads are able to connect to the network provided they meet the technical requirements. Under a constrained access model, access to network capacity is not guaranteed and available network capacity is allocated in real time in accordance with a generator's position on the dispatch schedule.

It is also possible that, before the end of AA4, the Government will reduce, or even remove, the 50 MWh per annum threshold at which a load becomes contestable.

Both these developments may require changes to the AQP if the policy is to be consistent with the new model. We see this as a further reason to avoid detailed consideration of the wording of policy, if stakeholder concerns can be addressed by inclusion of an overarching clause specifying how the policy is to be applied in practice.

6.3.3 Transparency

We detect in some submissions a concern that Western Power might apply the policy to its own advantage and in a manner that is not consistent with the objectives of the Code. This concern might be mitigated, and potential disputes avoided if Western Power is more transparent in its application of the policy.

We note that Western Power considers the GHD report to be confidential and has redacted the stakeholder submissions in Attachment A12.3 to the AAI. We acknowledge that withholding this information may be at the request of one or more submitters, although we note that both Synergy and Perth Energy, as well as other submitters, have publicly commented on the AQP in their submissions on the AAI. We have read both the GHD report and the unredacted Attachment 12.3 and cannot understand why any information in either document should be considered confidential.

Western Power is a publicly owned natural monopoly that is not exposed to competition and, in our view, should have less reason than many organisations to withhold information about its own operations. Withholding information about stakeholder input to the development of its policies can create the suspicion that it is developing and applying the policy for its own benefit, rather than for the benefit of its stakeholders.

6.4 CONCLUSION

Stakeholders, with the possible exception of Synergy, are generally positive about the changes to the AQP proposed by Western Power. In our view, most of the concerns raised by submitters would be addressed if a new clause 1.2 was included that explicitly requires Western Power to:

- act as a reasonable and prudent person in all matters relating to the processing of network access applications;
- act in a manner consistent with the objectives and requirements of the Access Code; and

- be transparent in its processing of access applications and avoid withholding information from applicants without good reason.

For the avoidance of doubt the policy should also state that access applicants have recourse to the disputes procedure in Chapter 10 of the Access Code should they consider that Western Power is applying the AQP in a manner that is inconsistent with this new clause.

If such a clause in added to the AQP, we see no need for further changes.

APPENDIX A

REVIEW OF SELECTED AA3 CAPEX PROJECTS AND PROGRAMS

A1 SHENTON PARK 132/11kV SUBSTATION

A1.1 SCOPE OF WORKS

Western Power is constructing a new 132/11 kV substation on land it owns adjacent to its existing 66/6.6 kV Shenton Park substation to accommodate load growth in the Western Terminal load area and allow the decommissioning of both the Herdsman's Parade and Shenton Park 66/6.6 kV substations. The Authority determined that the construction of the new substation met the requirements of the regulatory test in September 2012[11] and the project was committed for construction by the Western Power Board based on a very detailed business case dated April 2013. This business case included:

- construction of the new Shenton Park substation with two 66 MVA transformers;
- decommissioning the existing Herdsman's Parade and Shenton Park substations; and
- conversion of the distribution network supplied by the two substations from 6.6 kV to 11 kV.

A1.2 REGULATORY TEST

Western Power's regulatory test submission provided for the following:

- construction of the new Shenton Park substation with two 66 MVA transformers;
- construction of two new incoming 132 kV circuits between Western Terminal and the new substation; and
- conversion of the distribution network supplied by the two substations from 6.6 kV to 11 kV.

The submission supported this proposal with an analysis that compared four options for the development of the Western Terminal load area. Three of these options, including the two with the lowest net present cost, included the new substation at Shenton Park. The Authority determined that the substation satisfied the regulatory test but noted that this should not imply that it considered the proposed design met NFIT requirements. The determination suggested that further consideration be given to whether the substation could be supplied from the existing 132 kV line between the Western and Northern terminal stations, which is routed close to the Shenton Park site, and whether 66 MVA was an optimal transformer size, given that it had been decided to use 33 MVA in preference to 66 MVA transformers at the new Medical Centre substation.

Western Power's estimated cost for its regulatory test proposal was $39.55 million in 2011/12 dollars. This was an A1 estimate that included a risk provision of $1.67 million and an escalation provision of $3.97 million. It did not include the costs of decommissioning the two 66/6.6 kV substations, which Western Power said would be treated as non-recurring opex. The $39.55 million cost inflates to $43.61 million in 2017 dollars using the inflators in Western Power's regulatory model.

A1.3 BUSINESS CASE

The business case approved by the Board mirrored the regulatory test proposal except that:

- the substation would be supplied from the existing 132 kV line rather than from two new incoming circuits from Western terminal station;

[11] *Final Determination on the Regulatory Test for the Establishment for a new Shenton Park Zone Substation;* Economic Regulation Authority, September 2012.

- the cost of decommissioning the existing Shenton Park 66kV substation was included in the capital cost of the transmission project. Decommissioning of the Herdsman's Parade substation was included in the business case as a separate non-recurring opex project; and

- the business case cost estimate was \$47.35 million (nominal) compared to the regulatory test estimate of \$39.55 million (real, 2012). This updated estimate included the cost of decommissioning the existing Shenton Park 66kV substation, which was not provided for in the regulatory test submission.

According to the business case, the decommissioning of the existing Shenton Park substation would be treated as a sub-component of the substation construction project (T0348702) and was to be capitalised, possibly because part of the site was to be used for 11 kV capacitors. The decommissioning of the Herdsman's Parade substation, where the site would no longer be required for transmission purposes. was to be treated as a nonrecurring opex project. Table A1.1 shows the business case cost estimate in both nominal and real 2017 dollars.

It should be noted that the regulatory test estimate was a scoping phase estimate with an accuracy of +/-30%. Scoping phase estimates are used primarily for ranking alternative solutions to the need that a project is trying to address. The business case estimate was a planning phase estimate with an accuracy of +/-10%. Planning phase estimates use updated costs and incorporate project specific information acquired in the development of the preferred option. After developing a planning phase estimate, Western Power normally reviews its scoping phase options analysis to confirm that use of the more accurate estimate would not have altered the rankings of the various options.

[redacted]

[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note 1: Source: Business case – Table 4.
Note 2. Escalators taken from Western Power's AA4 regulatory model.

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]

A1.4 EXPECTED COST AT COMPLETION

Our analysis of the expected cost at completion based on the information provided by Western Power, and converting from nominal to real using the multipliers used by Western Power in its regulatory model, is shown in Table A1.3. This analysis suggests that the final project cost will be marginally lower than estimated in the business case. A cost overrun on the construction of the transmission works and the decommissioning of the 66 kV substations was offset by savings in the distribution component of the project.

Table A1.3: Expected Cost at Completion ($ million, real 2017)

Year Ending	AA2	AA3					AA4		Total
		2013	2014	2015	2016	2017	2018	2019	
Shenton Park construction	0.85	1.06	4.63	14.83	9.63	0.40	2.20	0.70	**34.30**
Shenton Park decommissioning		1.08							**1.08**
Herdsman's Parade decommissioning		1.40				0.10	1.00		**2.50**
Distribution works		0.32	2.82	4.84	2.55	1.70	0.50		**12.73**
Total	**0.85**	**3.86**	**7.45**	**19.67**	**12.18**	**2.20**	**3.70**	**0.70**	**50.61**

Reasons for the cost overrun in the transmission component included increased design complexity discovered during detailed design, the award of the contract to the second lowest tenderer due to safety considerations and ongoing contractual disputes, and environmental clean-up costs after asbestos fragments were discovered in the soil. Distribution costs were reduced by working collaboratively with existing high voltage customers to upgrade their networks to 11 kV, avoiding the need for step-down 11/6.6 kV transformers and a competitive market for the distribution works resulting in lower than expected costs for outsourced works.

A1.5 COMMENT

A1.5.1 Project Costs

While Western Power manages transmission and distribution works as separate projects, each subject to its own change control process, we have considered them together to be consistent with the business case and to recognise that the transmission and distribution works were interdependent. The project is still in execution, so the final cost of the project is not known. Nevertheless, cost information provided by Western Power suggests that the final cost of both transmission and distribution works taken together is likely to be very close to the business case cost estimate.

Table A1.3 shows decommissioning costs being incurred in 2013. Western Power has indicated that these are provisional amounts that have been added to the capital base in accordance with paragraph 16c of Australian Accounting Standard AASB116. This use of decommissioning cost provisions is discussed in Section 3.1.1.5. We suspect these provisions mean that decommissioning costs may have been double counted in Table A1.3 and the project cost has therefore been overstated.

We are not concerned by the increase in the cost estimated for the business case, compared with that for the regulatory test. The business case estimate was more carefully prepared, and incorporated additional information acquired during the planning phase.

A1.5.2 Economic Analysis of Design Options

Western Power considered two substation design alternatives, two 66 MVA transformers and three 33 MVA transformers. It selected the 66 MVA transformer arrangement because it had the lower net present cost and provided a higher N-1 security standard.

In commenting on the net present cost analysis of the two design alternatives, [redacted]

[redacted]

[redacted]

[redacted]

The larger spend requirements referred to occur in 2054 for the central growth requirement and 2045 for the high growth scenario. We are not impressed with this justification for the for the two-transformer option since we do not believe that a private sector investor would, in the normal course of business, consider it reasonable to commit to a higher up-front capital cost to avoid further capital expenditure that might occur in 2045. Had the net present cost been undertaken over a 25-year life, the three-transformer option would have been recommended as the cost of the replacement transformers in 2045 or 2054 would have dropped out of the analysis.

[redacted]

[redacted]

We assume that Western Power is saying that, notwithstanding the analysis it used elsewhere in the business case, had updated costs been used the outcome would have favoured the two-transformer option under all growth scenarios.

While we do not dispute this, we find the logic of the economic analysis in the business case difficult to follow. We do not think that A0 cost estimates, which use standard building blocks and have a level of accuracy of only +/-50%, should be used at a business case level as a basis for selecting between two competing options, particularly after more accurate scoping phase estimates were used for the regulatory test. We also think that once A1 cost estimates were available for both scenarios, the net present cost analysis should have been repeated using these more accurate costs and the result included in the business case.

A1.5.3 Design

A complication with the use of 66 MVA 132/11 kVA transformers, which are larger than Western Power's standard size of 33 MVA is that they have two 11 kV windings and the voltage on both is regulated by a single voltage regulator. This can be a constraint as situations can arise where independent regulation of the two windings is needed.

The final design for Shenton Park provides for this by incorporating:

- double bus 11 kV switchboards, that allow the load on individual switchboard feeders to be switch between the two transformer windings; and
- switchable 11kV capacitors which can be used to regulate the voltage of individual windings. These are being installed on the land where the old 66 kV substation was sited.

We understand the rationale for installing double bus switchboards as a second bus cannot be retrospectively added to a single bus design. However, it is not clear to us that the 11kV capacitors are also needed, particularly during the early years of service, when the load on the substation would be comparatively light. It may have been more cost effective to have designed the substation to provide for the later addition of capacitors, which would only be installed if control of network voltage became a problem. This would have reduced the initial cost of the project.

A1.6 CONCLUSION

We do not consider the inclusion of a $2.48 million provision in 2012/13 for the decommissioning costs of the two 66 kV substations is appropriate. It isn't clear to us that paragraph 16c of AASB116 should apply in Western Power's situation and we also note that clause 6.49 of the Access Code does not allow any amount in respect of forecast new facilities investment to be included in the RAB. We also think that decommissioning costs may have been double counted in Western Power's cost analysis. If this is the case, the project cost has been overstated by Western Power, and an adjustment is required.

The processes used by Western Power to develop and implement the project were robust and generally in accordance with Western Power's business processes. We therefore consider that all Western Power's expenditure on this project during AA3 meets NFIT requirements, apart from a potential adjustment to correct the treatment of decommissioning costs.

We do not think Western Power should have relied on A0 cost estimates in its business case analyses and it should also not be using 50-year lives in net present cost analyses, since any costs in the later years of such an analysis are highly speculative. However, we have not seen anything to suggest that these decisions affected the selection of the final project design.

We also think that it may have been possible to defer the installation of 11 kV capacitors but have seen nothing to indicate that this was considered. Any cost savings from such deferral would have been small relative to the total cost of the project and we are therefore not suggesting this concern be the basis for a reduction in the approved NFIT amount.

We note that the business case for this project was approved in the first year of AA3 and it may be that the issues raised in this review may already have been considered through Western Power's business transformation programme.

A2 MEDICAL CENTRE ZONE SUBSTATION

A2.1 SCOPE OF WORKS AND BUSINESS CASE

Western Power has constructed a new 132/66/11 kV zone substation in the grounds of the QEII Medical Centre to meet the following needs:

- Meet a customer request to upgrade the capacity of the substation to meet an increase in demand, driven by a redevelopment program within the health complex. Demand was forecast to increase from 12.5 MVA in 2012 to 23 MVA in 2015 and then to 27.5 MVA in 2020;

- Accommodate requests by both QEII and the University of Western Australia to increase the voltage at which they took supply from 6.6 kV to 11 kV;

- To increase the capacity and reliability of the distribution network by increasing the ability to transfer load between adjacent substations; and

- To replace zone substation assets at the existing 66/6.6 kV Medical Centre and University substations that were in poor condition and approaching the end of their economic lives. The new substation is replacing both substations.

In April 2008 the Authority approved a regulatory test waiver for the project and in October 2011 confirmed its ongoing validity.

As business case dated November 2012 was approved by the Board for the construction of a new Medical Centre substation (MCE) containing three 33 MVA, 132/66/11 kV transformers, associated distribution works, including the upgrading of the local distribution system from 6.6 kV to 11 kV and transferring all load on the existing Medical Centre (MC) and University (U) 6.6 kV substations to the new MCE substation and decommissioning the existing MC and U substations. The works covered by the business case did not include distribution works at the QEII complex, which were to be implemented separately by the customer as part of its redevelopment plans.

The business case considered the following configurations for the substation:

1. Two 66 MVA, 132/66/11 kV transformers;

2. Three 33 MVA, 66/11 kV transformers; and

3. Three 33 MVA, 132/66/11 kV transformers.

Option 2 above was rejected as having a higher nominal capital cost than the other two options[12] and because it didn't provide for a probable future upgrade of the transmission system in the Western Terminal load area to 132 kV. The cost of Options 1 and 3 were very similar so the main reason that Option 3 was preferred was that Western Power does not have any other 132/66/11 kV transformers in its fleet.

Two other features of the business case were of note:

- Western Power determined that replacement of the existing MC substation was not required until 2016. However, the customer required two transformers to be in service by 2014, and the business case provided for a customer capital contribution of $1.67 million to compensate Western Power for bringing the project forward by two years.

[12] We do not understand the reason for this as intuitively a 66 kV substation is less costly to build than a 132 kV substation of the same size. However, we are also surprised that this option was seriously considered given the very high probability that the transmission system will be upgraded to 132 kV.

- It was planned to install all three transformers at the same time, even though the third transformer was not required until 2016. This was because it was cheaper to install all three transformers as a single project than setting up a separate project for the third transformer. We concur with this.

The project is now complete apart from the decommissioning and site restoration of the old University substation, which is forecast for completion in 2017/18.

A2.2 PROJECT COSTS

A comparison of the actual (and forecast costs to completion) with the business case costs is given in Table A2.1. Business case costs include a risk provision and an escalation allowance.

Table A2.1: Estimated Project Costs ($ million, nominal)

	Project Numbers	Expenditure Type	Business Case	Actual
Construct new MCE substation	T0367820 T0368532	capex	29.07	26.67[1]
Decommission U substation	T0342732	opex	3.02	
		capex		1.80[1]
Distribution works	N0348860	capex	11.46	8.35
Total			**43.55**	**35.71**

Note 1: Estimated based on cost data provided by Western Power

The costs shown in Table A2.1 are our best estimate based on the information provided by Western Power. However, we are satisfied that the total cost of delivering the project was less than the business case cost estimate and there was no budget overrun.

We note that the cost of decommissioning the University substation and restoring the site is now being capitalised, even though it was treated as non-recurring opex in the business case. We assume this is due to a change in accounting policy. The business case had this expenditure occurring in 2017/18 outside the AA3 period and the $1.80 million decommissioning cost shown in Table A2.1 is also forecast AA4 expenditure. Given that the reported decommissioning expenditure in AA4 is significantly lower than the business case estimate there may have been some decommissioning expenditure during AA3, but we have not explored this[13].

A2.3 NFIT PRE-APPROVAL

On 13 June 2013, the Authority gave NFIT pre-approval[14] for expenditure of $24.43 million for this project. This NFIT preapproval covered:

- construction of the new 132/66/11 kV MCE substation with two 33 MVA transformers;
- upgrading Western Power's distribution system supplied from the 6.6kV MC substation to 11 kV and transferring this load to the new substation; and
- decommissioning the old MC substation.

Hence this NFIT pre-approval covered only part of the works approved by Western Power's November 2012 business case. It did not include installation of the third transformer, upgrading the distribution network supplied from the University substation to 11 kV and

[13] In information provided for our review, Western Power stated that there was $3.9 million (real, 2017) expenditure on Project T0368532 during AA3 and noted that: *This project has works performed over a number of projects in addition to the customer project.*

[14] *Final Determination on the New Facilities Investment Test Application for a 132-66/11 kV Medical Centre Zone Substation;* Economic Regulation Authority, 13 June 2013.

transferring this load to the new MCE substation or decommissioning and site restoration of the University substation.

NFIT pre-approval is provided for in Section 6.71 of the Electricity Networks Access Code, and provides an assurance that expenditure of up to the pre-approved amount on the works covered by the pre-approval will meet the requirements of the NFIT test. Pre-approval does not imply that expenditure over this amount will not meet NFIT requirements, but any expenditure over the approved amount would still be subject to ex-post approval. Therefore, it is not necessary to consider the implications of NFIT pre-approval for this review if we are satisfied that all the capital expenditure incurred on this project in AA3 meets NFIT requirements.

However, there is one aspect of the Authority's NFIT pre-approval that we do consider relevant. The pre-approval determination stated that while it was in order for Western Power to charge the customer for connection works, it should not charge a bring forward amount, since it considered that construction of the substation in 2014 would meet NFIT requirements, even if the customer had not required the provision of an 11 kV supply by that date. The rationale for this was that Western Power had previously stated that the assets the substation would replace were in very poor condition and the Authority's technical advisor considered that Western Power was taking a high risk continuing to run them. Hence the advice the Authority had was construction of the substation by 2014 could be justified on asset replacement grounds without considering any customer requirement for a higher voltage supply or additional load.

We tried to clarify this point with Western Power and were advised:

> *The Customer capital contribution was considered based on the associated brought-forward cost. The AA3 customer contribution was $0.7 million. Subsequent network development plans had forecast a need for completion of the new Medical Centre substation project by 2016. However, an access application submitted by the Department of Health has brought forward to 2014, the requirement for the new substation but with two transformers instead of three. Construction of the third transformer is not required to meet the customer's brought forward requirement but is to address identified network performance and compliance issues. Installation of the third transformer will also be brought forward to 2014, as this is demonstrated to be more cost efficient than installing it as part of a separate project in 2016.*

We can only conclude that Western Power has accepted a brought forward contribution, notwithstanding the Authority's pre-approval determination on this matter. Capital contributions should not be included in the NFIT amount.

A2.4 CONCLUSION

We consider the capital expenditure on this project during AA3 to be efficient and to meet NFIT requirements subject to the following provisos:

- Capital contributions do not meet NFIT requirements. Western Power has advised that it received a $0.7 million bring forward customer contribution for this project notwithstanding the Authority's finding in its NFIT pre-approval determination that no bring forward contribution was warranted as construction in 2014 could be justified on asset replacement grounds;

- While the decommissioning of the University substation was treated as non-recurring opex in the business case, Western Power is now planning to capitalise this expenditure. While we are not accountants, it is not clear to us that Western Power should be capitalising decommissioning costs on a site it no longer requires.

A3 MUJA TRANSFORMER FAILURES

A3.1 INTRODUCTION

In September 2012, bus tie transformer BTT1 at the Muja power station switchyard, rated at 490 MVA, 330/132 kV unexpectedly failed in service. Following this failure, in February 2014 BTT2 in the same switchyard, rated at 395 MVA, 220/132 kV also failed in service. The simultaneous unavailability of the two bus tie transformers in the same switchyard created an unforeseen operating situation where there was no infeed to the Muja 132 kV bus from the 330 kV network[15]. The failures constrained the power flow from Muja to the Eastern Goldfields and limited the ability of the network to supply Albany and other towns south of Muja connected to the 132kV system. To avoid these constraints System Management had to dispatch the old coal fired generators at Muja A and B power stations and the open-cycle gas turbines at Kalgoorlie out of merit, imposing significant additional generation costs on the West Australian Electricity Market.

A3.2 TRANSFORMER MANAGEMENT

Both transformer failures were unexpected in that the transformers were only half way through their economic lives and Western Power's routine condition assessments had not shown any indication of imminent failure. The most likely cause of the BTT1 failure was arcing in the tap changer which was most likely a result of a defect during manufacture or assembly on site. BTT2 most likely failed due to an internal fault in the blue phase tertiary winding.

The management of transformers at Muja was an area of special focus for the 2014 independent asset management review undertaken by Jacobs in accordance with the requirements of Western Power's electricity transmission and distribution licences. Jacobs reviewed the maintenance history and historic condition assessment results for all three bus tie transformers at the Muja power station and reported that the maintenance undertaken on the power transformers was appropriate and that condition assessments gave no cause for concern. Neither transformer had been heavily loaded during its life and, interestingly, it noted that more maintenance issues had been identified with the third bus tie transformer than with either of the two units that failed. It also considered that Western Power's actions following the failures, including the commissioning of independent reports and the installation of online dissolved gas analysis on BTT3 and BBT1's sister transformer at Southern Terminal station were appropriate.

A3.3 REPLACEMENT OF BTT1

Following the failure of BTT1, Western Power ordered a like for like replacement from a reputable manufacturer with a good market reputation, with an agreed delivery date of June 2013. However, this unit failed three consecutive factory acceptance tests and had still not been delivered when the second failure occurred

After the transformer failed the third factory acceptance teat, Western Power's emergency management team recommended the procurement of a new transformer and either renegotiating or terminating the original transformer procurement contract. In the event:

- Four vendors responded to a request for tender for the new transformer. The best offer was 20% higher than the contract price for the original transformer and had an indicative in-service date of November 2015.

- Western Power was able to renegotiate the original contract under the following terms:

[15] There is also a 330/220 kV bus tie transformer at Muja, which would normally provide an alternative 132 kV infeed from the 330 kV system via the 220 kV busbar.

- a reduction in the contract price of 40%, provided the transformer passed the 4th factory acceptance test. Should the transformer fail this test, then the contract would be terminated at no cost to Western Power;

- an in-service date of April 2015; and

- a warranty extension from 5 to 7 years.

Western Power decided to accept both offers. The first offer provided an earlier delivery date and a low-priced transformer. The second offer provided insurance if the original replacement failed a fourth acceptance test, and otherwise would be used as a strategic spare. Western Power has 15 transformers of the same rating in service, four of which are showing signs of deterioration.

The original transformer passed its fourth acceptance test and is now in service at Muja. The strategic spare was delivered for 9% below the approved budget and, despite a delivery delay, was available for use by the required in service date of November 2015.

A3.4 REPLACEMENT OF BTT2

Following the failure of BTT2 Western Power undertook several minor system interventions, such as the relocation of a reactor to address voltage issues at Albany, to improve system security. It also relocated a 120 MVA transformer from Merredin to Albany, as an interim replacement. However, this transformer was undersized and constrained the power transfer limit to the e/astern Goldfields to 100MW, whereas the peak power transfer in 2013 had been 156 MW.

Western Power is currently installing a new 250 MVA transformer at Muja as a permanent replacement for the failed unit. This should be in service by the end of 2017. Actual expenditure to the end of AA3 on installing this replacement unit and associated work was $9.0 million (real 2017) and the total expenditure on completion is expected to be within the business case budget. We note that the replacement 250 MVA transformer is smaller than the 395 MVA unit it is replacing, reflecting a prudent approach to transformer sizing.

Western Power has received insurance payouts in respect of both transformer failures and has treated these as revenues from the disposal of assets. We have not considered whether this accounting treatment was appropriate.

A3.5 CONCLUSION

Western Power's management of the two transformers prior to failure was in accordance with good electricity industry practice and the failure of the two units at the same site within such a short period appears to have been an unfortunate coincidence. Had the replacement unit for the BTT1 unit not failed successive factory acceptance tests, it would have been in service before BTT2 failed and the consequences for Western Power and the operation of the wholesale electricity market would not have been so serious.

Western Power's response to these events has been appropriate and the works have been undertaken in accordance with Western Power's capital expenditure development and implementation processes. We think the full capital expenditure on all three transformers, including the new strategic spare, meets NFIT requirements.

We have not considered whether the accounting treatment of the insurance payouts was appropriate.

A4 DISTRIBUTION WOOD POLE REPLACEMENT

A4.1 BACKGROUND

In 2006, Energy*Safety* audited Western Power's wood pole management practices. Following this audit and a subsequent 2008 review of Western Power's efforts to meet the recommendations contained in the audit report, Western Power was issued with Energy*Safety* Order 01-2009. The Order was comprehensive and covered condition assessment and management of the wood pole fleet. A key requirement was that Western Power replace or reinforce unsupported rural wood poles that did not meet specified wind speed design criteria. by 31 December 2015.

Non-compliance with the specified criteria can be due to (i) design deficiencies resulting in the pole being under strength at the time of installation, (ii) the subsequent addition of pole hardware such has a transformer without checking that the pole has sufficient strength to carry the extra load or (iii) deterioration in service, which most commonly manifests itself in the loss of good wood below ground level.

Initially Western Power had difficulty accurately identifying the poles that were required to be replaced under the Order because its condition assessment methodology was not reliable in assessing the strength of a pole below ground level and because it did not have a process in place to accurately determine the required pole strength based on the mechanical loading imposed by the hardware mounted on the pole.

Therefore, mid-way through the Order period, Western Power decided to discontinue its reliance on drilling poles to assess residual ground-line strength and moved instead to meet the intent of the Order through a deterministic approach that required reinforcing or replacing all untreated hardwood poles in rural areas that had been in service for 25 years or longer. At the time of the AA3 submission it estimated that this would involve the replacement of 140,000 wooden poles and the reinforcement of up to 110,000 poles. Since this volume of replacements and reinforcements was considered undeliverable, it based its AA3 wood pole replacement forecast on the replacement of 100,000 poles and reinforcement of a further 64,000 poles by the end of AA3. Many of these poles were already reinforced but the reinforcement methods were considered substandard, in that they were not considered to have the strength required to meet Energy*Safety's* requirements. At the time all parties acknowledged that this proposal would not fully meet the requirements of the Order

In its further final decision, the Authority accepted Western Power's proposal on the basis that, while it would not fully meet the requirements of the Order, it was the most that could be expected to be achieved given the financial and deliverability constraints. The decision also included wood pole replacements in the access arrangement's investment adjustment mechanism, which meant that if Western Power was able to treat more poles than forecast, the additional expenditure would be funded provided it met NFIT requirements.

A4.2 IMPLEMENTATION

The Western Power Board considered and approved two business cases for distribution wood pole replacements and reinforcements. The first business case in May 2012 covered the first two years of AA3 and was generally consistent with the draft decision. The second business case in March 2014 covered the final three years of AA3 and treated wood pole management as part of a wider asset replacement program that sought to remediate the highest risk assets across a range of asset classes and to optimise delivery by bundling the replacement of different asset types within a single maintenance zone. Actual costs, volumes and unit rates achieved are compared with the AA3 forecasts and the business cases in Tables A4.1 to A4.3 below.

Table A4.1: Cost of AA3 Pole Replacements and Reinforcements ($million, real 2017)

Year ending	2013	2014	2015	2016	2017	Total
AA3 Final Decision[1]	181.4	207.7	219.5	231.3	245.1	1,085.1
Replacements						
AA3 Final Decision	124.0	135.1	148.5	163.0	177.0	747.6
Business Case	127.3	141.4	228.0	225.7	221.4	943.8
Actual	170.5	225.1	184.9	168.8	80.9	830.2
Reinforcements						
AA3 Final Decision	58.4	72.7	73.4	74.2	75.8	354.6
Business Case	58.4	72.8	150.7	105.0	59.6	446.5
Actual	51.0	67.1	57.5	21.3	9.1	206.6
Total						
AA3 Final Decision	182.5	207.8	221.9	237.2	252.8	1,102.2
Business Case	185.8	214.2	378.7	330.7	281.0	1,390.4
Actual	221.5	292.2	242.3	190.1	90.6	1,036.7

Note 1: Forecast taken from Western Power's AA4 regulatory model as the numbers in the Authority's AA3 final decision did not include real cost escalation

Table A4.2: Volumes of AA3 Pole Replacements and Reinforcements

Year ending	2013	2014	2015	2016	2017	Total
Replacements						
AA3 Final Decision	16,500	18,000	19,500	21,000	22,500	97,500
Business Case	16,500	18,000	23,000	23,000	23,000	103,500
Actual	16,930	23,147	17,052	16,876	8,294	82,299
Reinforcements						
AA3 Final Decision	45,000	55,000	55,000	55,000	55,000	265,000
Business Case	45,000	55,000	135,000	95,000	55,000	385,000
Actual	47,677	66,841	53,256	13,601	7,545	188,920

Table A4.3: AA3 Pole Replacements and Reinforcements Unit Rates ($, real 2017)

Year ending	2013	2014	2015	2016	2017	Average
Replacements						
AA3 Final Decision	7,515	7,506	7,616	7,762	7,867	7,653
Business Case	7,718	7,854	9,914	9,813	9,626	8,985
Actual	10,071	9,724	10,841	10,003	9,754	10,079
Reinforcements						
AA3 Final Decision	1,299	1,322	1,335	1,349	1,378	1,337
Business Case	1,299	1,324	1,116	1,105	1,084	1,186
Actual	1,070	1,004	1,079	1,566	1,286	1,201

A4.3 ENERGY SAFETY REVIEW

As noted in Section A4.1, Energy*Safety* Order 01-2009 required Western Power to achieve full compliance by 31 December 2015. During the first half of 2016 Energy*Safety* reviewed Western Power's compliance with its order and on 10 June 2016 issued a report that found that:

> *…the principal public safety objectives set out in the Order have been achieved. The Director of Energy Safety is therefore satisfied that Western Power has complied with the Order as at 31 December 2015[16].*

The review found that:

- Western Power had replaced or reinforced to a safe standard all hardwood poles on its rural network by 31 December 2015 and in doing so met the intent of the order. It made this determination using a statistically valid sampling process; and

- Western Power had improved its wood pole management plan to the point where Energy*Safety* considered it to be an acceptable basis for managing the safety risks of its wood pole fleet going forward.

A4.4 COMMENT

At the time of submitting its AA3 proposal, Western Power faced three problems that constrained its ability to fully comply with the Energy*Safety* Order.

1. It had not found a methodology that would reliably assess the condition of its hardwood poles and, partly because of this, did not have a management plan in place that would allow it to identify individual hardwood poles that required replacement in accordance with the Order. Its solution was to replace or reinforce all hardwood poles in rural areas that had been in service for 25 years or longer;

2. It did not have the delivery capacity to replace or reinforce the number of poles that would need to be replaced in accordance with its deterministic replacement policy. Pole reinforcement was a problem, as many of its existing reinforcement systems were considered to have inadequate strength. There was only one pole reinforcement contractor available that was acceptable to Western Power and this contractor had capacity limitations;

3. The total cost of complying with the Order was considered prohibitive, given the number of poles believed to require treatment under its deterministic treatment policy.

Western Power has addressed these issues to the point where it has been able to comply with the Order to that satisfaction of Energy*Safety* and at the same time significantly reduce the forecast volume of pole replacements going forward without compromising its level of wood pole risk. It has done this by introducing significant improvements to its pole management strategy. We have not considered it necessary to review this strategy in detail as this was done by Energy*Safety,* but it is likely to involve implementation of a more reliable pole condition assessment approach and collection of sufficient data on each individual pole to enable the external pole load to be accurately determined and the residual strength to be calculated.

This increased data granularity should allow a decision on whether replacement or reinforcement is needed to be made at an individual pole level, based on the actual strength of the pole determined by accurate data on pole type and condition, the external pole loading determined by the hardware mounted on the pole and the number and types of conductor and span lengths supported, and the consequences of failure, which is dependent on pole location.

An assessment at this level of granularity of the need to replace or reinforce a pole is likely to significantly reduce the number of pole treatments required. For example, the initial estimate of required pole treatments assumed that all legacy pole reinforcements were inadequate and would require upgrading as part of the program. However detailed analysis and testing showed that 41 of the 72 legacy reinforcements were satisfactory, resulting a in significant reduction in the number of pole treatments required.

16 *Order No 01-2009, Review of Western Power's Compliance;* Energy*Safety* WA, Ref E2016-3162, 10 June 2016.

This impact can be seen from Table A4.2 above, which shows the number of poles treated during AA3 to be lower than both the approved forecast and the business case, with significant reductions in the final two years. The Energy*Safety* review notes:

> *On 13 December 2013, the Director of Energy Safety wrote to Western Power's Board to acknowledge that the new management plan along with the 'reinforce or replace' strategy would satisfy five of the six sections of the Order. His letter also confirmed the sixth section, concerning the rural electricity network poles, had not been met and would require greater effort if compliance was to be achieved by 31 December 2015, as required by the Order.*
>
> *On 17 December 2013, Western Power's Chairman wrote to the Director stating that reinforcing and replacement capacity were being increased significantly and Western Power expected to complete the Order requirements for the rural distribution system by the due date of 31 December 2015.*

and further:

> *Western Power wrote to the Director on 16 December 2015 … confirming it had properly reinforced or replaced all untreated and inadequately reinforced hardwood poles which had been in service for 25 years or longer in its rural networks.*

This 2013 change in strategy was to be implemented primarily by engaging a second contractor to increase the number of pole reinforcements that Western Power could deliver. This is shown in Table A4.2, where Western Power delivered 66,841 pole reinforcements in 2013/14 and obtained business case approval for reinforcing 230,000 poles over the two-year period 2014-16, most of which presumably would be installed prior to 31 December 2015. In the end, this number of replacements was not needed, presumably because of the impact of the improved asset management strategy described above.

A4.4.1 Unit Rates

It can be seen from Table A4.3 that Western Power was not able to achieve the unit pole replacement rates assumed at the time of the AA3 review and the preparation of the 2012-14 business case, and that there was a step change in the unit cost of pole reinforcement in 2015/16. Western Power has offered the following explanations for the increased cost of pole replacements:

- the impact of the need for greater utilisation of external contractors with higher unit rates to ramp up delivery to meet the Order;
- a higher proportion of complex poles being treated than forecast based on historical rates. For example, it costs more to replace a transformer pole than a pole that supports only a phase and earth conductor;
- more accurate recording of work types (now four different types of pole types and their corresponding costs can be tracked, rather than a single average)
- a change to the accounting treatment of unplanned pole replacements which increased the proportion of the replacement cost capitalised from around 40% to 100%.

Reinforcement unit rates were stable across the first 3 years of AA3 and were below both the AA3 and internal unit rate forecasts. The obligation to ensure that all rural distribution wood poles are structurally safe by 31 December 2015 to satisfy the Order, required reinforcement of geographically disperse rural wood poles. This resulted in an additional $5 million in contractor variation costs hitting the reinforcement program and resulted in a step change in 2015/16 unit rate.

Reinforcement unit rates in 2015/16 and 2016/17 were also impacted by the substantial reduction in volumes which resulted in volume discounts that Western Power had agreed with the supplier being removed. AA3 forecast reinforcement volumes were informed by the assumption of a requirement to remediate all legacy reinforcements, as discussed in Section A4.4.

A4.5 CONCLUSION

Pole replacement and reinforcement costs were significantly higher in the first years of AA3 because poles were replaced that in hindsight were still in satisfactory condition and were not overloaded. However, Western Power was under intense pressure from both Energy*Safety* and the Government to reduce the public safety risk of its wood pole fleet and to comply with the requirements of the Energy*Safety* Order. The wood pole management strategy that it currently uses, which we understand analyses each individual pole using highly granular data, has been developed over several years and required a significant investment in research and development. It was not available to Western Power until the middle of the AA3 period

Over the whole of AA3, Western Power was replaced 15% less poles and reinforced 29% less poles than forecast at the beginning of the period. Notwithstanding this, Energy*Safety* has confirmed that it has fully complied with the intent of its 2009 Order and has also endorsed its current wood pole management strategy as an appropriate basis for managing its wood pole fleet going forward.

While Western Power was able to deliver its wood pole reinforcements at an average unit rate 10% lower than the AA3 forecast its average pole replacement unit rate across the period was 32% higher than forecast. It has provided explanations for this increase that we consider satisfactory.

We therefore consider that all distribution wood pole expenditure over the AA3 period meets NFIT requirements and should be included in the AA4 opening RAB. This expenditure amounted to $1,041.8 million[17] (real 2017) compared to a forecast of $1,085.1 million (real, 2017). As distribution wood pole management was subject to the investment adjustment mechanism, a reduction of $43.3 million (real, 2017) is indicated.

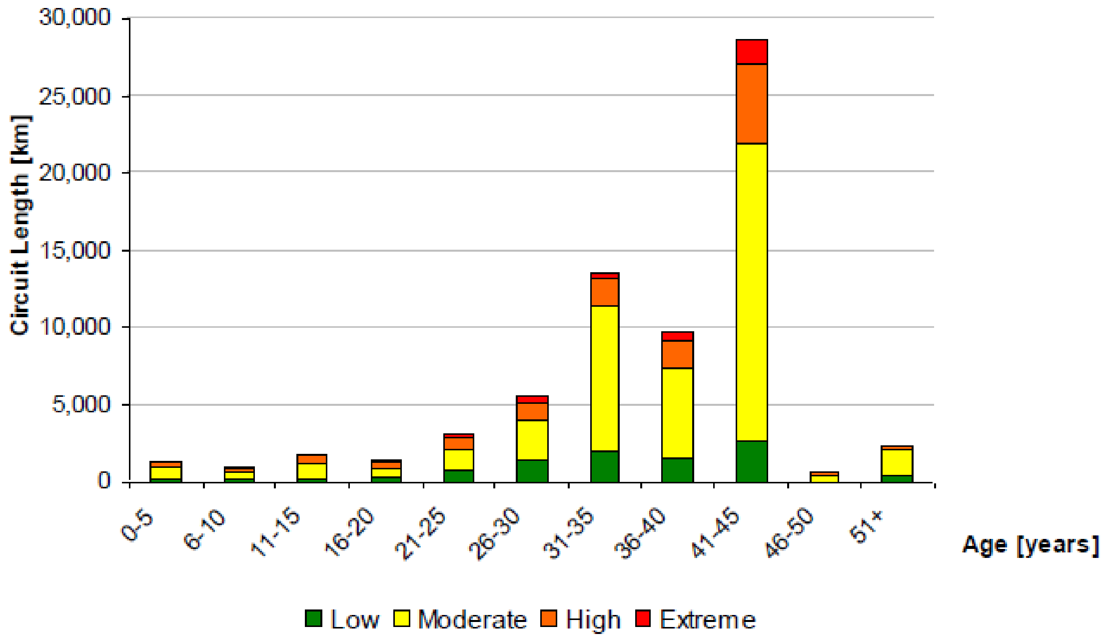
[17] This is higher than the $1,036.7 million shown in Table A4.1. This is because the actual AA3 costs shown in the tables were taken from Western Power's compliance summaries and differ from the numbers in its revenue model. While the difference is not material Western Power has confirmed that the expenditure of $1,041.8 million used in its revenue model is accurate.

A5 DISTRIBUTION CONDUCTOR REPLACEMENT

A5.1 BACKGROUND

The total length of Western Power's distribution overhead conductors is approximately 69,000 circuit km. Of this total, approximately 25,000 circuit km is approaching the end of its design life and presents a heightened likelihood of failure. Figure A5.1, which shows an age profile of distribution overhead conductors categorised by fire risk zone, illustrates this. The life of an overhead conductor is typically around 50 years but can vary with the size and type of conductor, and the environment in which it is installed.

Figure A5.1: Conductor Age Profile Categorised by Fire Risk Zone



Conductors that are shown to have the highest risk of failure are thin gauge copper, steel conductor older than 40 years and steel reinforced aluminium conductor (ACSR) between 20 and 40 years old, which has been shown to exhibit accelerated corrosion of the steel core due to an issue with the application of grease on the internal steel strands.

A5.2 IMPLEMENTATION

The Western Power Board considered and approved two business cases for conductor replacement replacements and reinforcements. The first business case in Jun 2012 covered the first two years of AA3. The second business case in March 2014 covered the final three years of AA3 and treated conductor replacement as part of a wider asset replacement program that sought to remediate the highest risk assets across a range of asset classes and to optimise delivery by bundling the replacement of different asset types within a single maintenance zone. Actual costs, volumes and unit rates achieved are compared with the AA3 forecasts and the business cases in Tables A4.1 to A4.3 below.

Table A5.1: Cost of AA3 Distribution Conductor Replacement ($million, real 2017)

Year ending	2013	2014	2015	2016	2017	Total
AA3 Final Decision	37.3	39.7	43.7	52.3	59.2	232.1
Business Case	40.1	66.5	150.8	203.3	241.4	702.0
Actual	60.6	96.5	107.4	109.6	92.0	466.1

Table A5.2: Volumes of Distribution Conductor Replacement (circuit-km)

Year ending	2013	2014	2015	2016	2017	Total
AA3 Final Decision	431	463	497	578	654	2,623
Business Case	250	450	550	653	718	2,621
Actual	279	417	418	679	503	2,296

Table A5.3: AA3 Conductor Replacement Unit Rates ($, real 2017)

Year ending	2013	2014	2015	2016	2017	Average
AA3 Final Decision	86,448	85,793	87,851	90,471	90,520	88,217
Business Case	160,235	147,739	274,105	311,265	336,212	245,911
Actual	217,299	231,375	256,949	161,383	182,903	209,982

The above tables indicate that while distribution conductor replacement expenditure was twice as much as approved in the AA3 forecast, the circuit length of conductor replaced was 12% less, resulting in a unit rate across the whole period 138% higher than forecast. It also shows that expenditure over the first two years of the period was 47% higher than the corresponding approved business case, while over the following three years it was 48% lower.

A5.3 COMMENT

At the time of preparing its AA3 forecast Western Power's conductor replacement program was largely driven by the location of conductor failures during AA2. As a result, 41% of the proposed conductor replacements by circuit length were in medium to low fire risk areas and involved the replacement of conductor on single phase lines. The remaining 59% targeted conductors in high fire risk areas where the replacement conductors were on a mixture of single phase lines and three phase lines in urban areas. As the unit cost is normalised by circuit-km, it is higher for three phase lines in populated areas than for single phase lines in rural areas.

Our analysis of the information provided by Western Power in the implementation of its conductor replacement program has highlighted the following issues.

A5.3.1 Risk Management

Early in the AA3 period Western Power changed the focus of its conductor replacement program from simply reducing to incidence of conductor failure to mitigating the potential consequences of such failure. This meant targeting population centres within extreme/high bush fire risk zones since the co-existence of bush fire risk and electric shock risk in these areas represented the greatest potential consequences from at-risk conductors. Given the equal weighting of bushfire and electric shock risk, the second tier of priority was remaining higher risk conductor in populated areas or in rural areas of extreme/high bush fire risk zones. Within these priority areas and through detailed analysis, further prioritisation occurred in line with the asset condition ranking to ensure the highest risk assets were addressed as a priority. A consequence of the change of focus was an increase in the unit costs of the program.

A5.3.2 Unit Costs

Notwithstanding the impact of the risk management focus, Western Power still had problems managing the cost of the work, as evidenced by the high unit costs over the first three years as shown in Table A5.3. Western Power has said that it introduced the following measures to manage this issue:

- check points to assist monitoring of cost over-runs at the post-design, pre-contract, and final estimate stages;
- a decision to hold or postpone conductor replacement projects if forecast cost over-runs were greater than 10%;
- a decision to take any forecast cost over-runs greater than those afforded by the increased business case value to Executive Managers for resolution;
- a revision of the building blocks that capture the materials requirements and associated costs for individual items used in the design of the network and adjustment of the Distribution Quotation and Management (**DQM**) system estimates for replacing conductors to reflect more accurate costs.

The revision of the cost estimation building blocks would seem to be reflected in the high business case unit costs for the final three years of AA3, as shown in Table A5.2. We note that the actual unit costs in 2015/16 and 2016/17 were lower than the previous three years although the extent to which this can be attributed to improved cost management is not clear. This could, in part, be due to efficiencies captured through adopting a zonal approach to distribution network maintenance.

A5.3.3 Change Control – 2012-14

As the total cost of conductor replacement in 2012/13 was $19.2 million greater than estimated in the Business Case, and the forecast total cost of conductor replacement was anticipated to be $25.4 million higher than that budgeted in the business case, a Change Control Request was approved on 3 December 2013 to increase the business case value by 44%. The impact of this is not shown in Table A5.1, which shows that actual expenditure over these two years was 47% higher than the budget in the original business case. This shows that the cost overrun was managed and approved at Board level, although the approval of the 2012/13 overrun was retrospective and thus not fully compliant with good practice or Western Power's expenditure management practices.

A5.3.4 Change Control – 2014-17

In 2014-17, the expenditure budgeted in the original business case was almost three times the amount provided for in the AA3 forecast but the planned replacement circuit length was only 11% higher. This reflected Western Power's conviction that the condition of much of its distribution conductor constituted a high public safety risk and it was therefore important to maintain the conductor replacement momentum planned for AA3, notwithstanding the substantially higher unit replacement costs. However, the Board's approval of this business case, was contingent on securing approval for additional expenditure of $979.4 million (nominal) above Western Power's 2014-17 state budget allocation.

As Western Power was not successful in securing this funding approval, a Change Control Request was approved on 21 December 2015, incorporating a revised budget and work plan, as shown in Table A5.4.

Table A5.4 Revised Budget and Work Plan, 2014-17

	2014/15	2015/16	2016/17	Total
Costs ($ million, real 2017)				
Change control request	52.9	162.1	133.6	348.6
Actual	107.4	109.6	92.0	309.0
Volumes (circuit-km)				
Change control request	236	602	866	1,704
Actual	418	679	503	1,600
Unit rates ($, real 2017)				
Change control request	224,280	269,227	154,273	-
Actual	256,949	161,383	182,903	-

TableA5.4 indicates that across the three-year period, the total circuit length of conductor replaced was 6% lower than forecast, whereas the cost was 11% below the revised budget.

The abnormally high unit cost in 2014/15 was due to in high cost of installing Hendrix type insulated conductor, which was not used in either of the following two years. Western Power has also noted that the lower unit rates in the final two years was partly due to an accounting adjustment that journaled out the pole replacement costs. This was a new initiative to improve the implementation of replacement works under specific programs to more accurately reflect the work completed.

Western Power also noted that during the latter part of the period a business transformation initiative focussed on obtaining better information regarding conductor condition by sampling and the use of metallurgical testing. As a result, some conductor replacements were cancelled.

One issue that Western Power has not explained is the budget overrun in 2015/16, where actual expenditure was substantially higher than the revised budget approved in December 2015, a full six months after the end of the financial year. We suspect that the budget overrun was due to the expectation that the business case budget would be approved by Government, but this does not explain why management went to the Board seeking approval for a budget that it already knew had been exceeded by a substantial margin.

A5.4 CONCLUSION

As can be seen from Figure A5.1, approximately 40% of the 69,000 circuit-km of distribution conductor on Western Power's network is now more than 40 years old. As conductor failures pose a public safety risk in that they can start bush fires and potentially cause electric shocks, this age profile indicates that Western Power is prudent in proactively undertaking a conductor replacement program to avoid a repeat of the situation it found itself in some years ago with its wood pole fleet.

The total circuit-km of conductor replaced during the AA3 period was 88% of the length forecast at the start of the period, but the cost of the program was more than double the approved forecast. While this was due to several factors, the decision by Western Power to focus on reducing the potential consequences of a conductor failure when prioritising projects to be included in the program, rather than on simply reducing the number of failures, was a significant driver of the higher unit rates. This change of focus meant that a much larger proportion of the program involved the replacement of conductors on three phase circuits in populated areas and in extreme and high bushfire risk zones. As a result, the unit rates assumed at the time of the AA3 review ceased to be relevant. We consider circuit-km a crude normaliser for assessing unit rates of conductor replacement because of the wide spectrum of rates involved – the cost of replacing the conductor on a three-phase circuit in a built-up area is many times the cost of replacing the conductor on a similar length of single phase circuit in a sparsely populated rural area. We are satisfied that

Western Power took appropriate steps to minimise the cost of the work undertaken under this program.

We note that, because of a business transformation initiative, Western Power is now using conductor sampling and metallurgical testing to assess conductor condition more accurately and therefore giving condition a higher weighting when assessing projects to be included in the program. This is a worthwhile initiative.

While the total expenditure on this program was more than twice the approved AA3 forecast, we believe it fully meets NFIT requirements and should all be included in the opening AA4 RAB.

A6 PERENJORI BATTERY ENERGY STORAGE SYSTEM

A6.1 BACKGROUND

Western Power has installed a battery energy storage system (BESS) at Perenjori on the Three Springs 611 Morawa feeder to:

- improve reliability of supply for customers in Perenjori township in line with its distribution network reliability performance strategy for AA3;
- understand the financial costs and benefits, reliability of systems and customer response to a BESS;
- identify the implementation / business model for best-practice in the development of a BESS as an alternative to traditional solutions to improve poor reliability performance in other parts of the network;
- provide Western Power with the opportunity to develop its capability in utility scale battery storage solutions on the network to potentially develop options for other areas with similar characteristics; and
- understand the most appropriate model for customer engagement.

Perenjori was selected as the Morawa feeder was a high contributor to SAIDI and SAIFI and was not meeting the distribution service standard benchmark for rural long feeders. It is a small town located on the edge of the distribution network.

The business case was approved in May 2016 with a capex budget of $4.66 million. Actual AA3 capex was $3.83 million but it is not clear whether any residual capex will be spent on the project in AA4.

A6.2 BUSINESS CASE ANALYSIS

We have not undertaken a detailed assessment of the financial analysis due to time constraints and relatively small project value, but our understanding from a high-level review is that:

- the main driver for the project was to gain experience in the application of utility BESS. The project will benefit only a small number of customers located close to Perenjori town, rather than all users on the Morawa feeder. Following a feeder fault the section of the network feeding these users will be islanded from the rest of the grid and will experience an interruption of less than 150ms, which is for practical purposes an uninterrupted supply, and supplied from energy stored in the BESS;
- the business case considered five different options, the BESS and four different network alternatives. The BESS had a much lower initial cost than the any of the network options ($4.66 million compared to $7.89 million) but had a marginally higher NPV over a 40-year project life than the lowest cost network alternative. The option of using a diesel generator instead of a BESS was not considered as it would make not provide a SAIFI benefit;
- the business case also reported an NFIT analysis of the project. This analysis estimated the annualised stakeholder benefit from the project, which comprised a reduction in energy not supplied, calculated at the value of lost load, and an annual benefit to Western Power in the rewards (or reduction in penalties) from the service standard adjustment mechanism. It then estimated that the total stakeholder benefits would sustain a capital investment of $2.49 million, calculated by equating the annualised cost of the capital investment to the annual benefits to Western Power and network users because of the project. The $2.17 million difference

between this and the actual cost of the project was considered to be "at risk" of not meeting NFIT requirements; and

- as this was a research and development project, the business case estimated that it would attract research and development tax benefit with a present value of $1.89 million.

A6.3 COMMENT

- We think it reasonable that Western Power engage in small-scale research and development projects of this type to gain experience in the application of emerging technologies and their potential impact on the network and Western Power's operations.

- We do not think the BESS system and the lowest cost network comparator were equivalent options. While the network option was not fully scoped in the business case it is likely to have a higher overall benefit because it would likely improve supply to all users connected to the Morawa feeder, not just those close to Perenjori town. That said, the BESS is likely to provide a much higher quality of supply to the Perenjori town users that the project benefits, to the extent that assuming the trial is successful Western Power may find it difficult to relocate the BESS when it does eventually upgrade the feeder.

- While we do not know what assumptions were used in the 40-year net present cost analysis, we do not think that this type of analysis should be undertaken over such a long project life, given the uncertainty of any assumptions beyond about 20 years. This has also been discussed in Appendix A1. For example, a battery life of 20 years has been assumed. In 20 years' time it is conceivable that the cost of small scale battery-solar generating systems will have reduced and the technology would have been refined to the point where supplying small towns like Perenjori though a long grid supplied rural feeder is no longer the most cost-effective solution.

- This is the only instance where we have seen Western Power use an annualised cost benefit analysis to justify the NFIT compliance of a project intended to provide reliability of supply. It has generally been Western Power's practice to assume that such a project meets the second leg of the NFIT test. The issue of NFIT compliance then rests on the first leg where Western Power must show that it has effectively minimised costs and that the project exhibits appropriate economies of scale or scope.

- If the project was to be subject to an NFIT assessment based on economic considerations, it is not clear that the diesel generation should have been dismissed so readily. A generator would have had a much lower capital cost, although operating costs would have been higher. Economic benefits from a reduction in lost load would have been similar and the project would still have delivered an (albeit smaller) service standard adjustment mechanism benefit through an improvement in SAIDI. It is also possible that a generator would have been more readily scalable so would have provided benefits to a greater number of users.

A6.4 CONCLUSION

It seems clear to us that the primary objective of this project was to trial the use of a utility scale BESS as an alternative means of providing a reliable power supply, and improvement in reliability to users in Perenjori town was secondary to this. We therefore question the relevance of much of the economic analysis, since the analysis was premised on reliability improvement being the primary benefit.

The business case concluded that 44.5% of the expenditure on this project is "at risk" of not meeting NFIT requirements, and we commend Western Power for voluntarily nominating this project for inclusion in this review for this reason. This conclusion was based on a perception that the current regulatory framework does not support small scale research and development initiatives unless they can be shown to be economic.

Our assessment of this project for NFIT compliance has been influenced by our view that a regulator should not put impediments in the way of a distribution business undertaking *small scale* research and development into the likely impacts of new and disruptive technologies. We note from the public submissions on Western Power's AA4 AAI that many stakeholders would agree with this, and that the primary concern in regulatory scrutiny of initiatives involving the use of new and disruptive technologies relate not to the use of the technologies but to the scale of the rollout and the magnitude of the cost to customers if the forecast benefits do not materialise.

In our view all capital investment in the project meets NFIT requirements, in that it maintains the reliability of the covered network and is of a size and scale appropriate to a small-scale research and development project. However, any research and development tax incentive received by Western Power because of the project should be treated as a capital contribution to the project rather than a windfall gain to Western Power.

A7 PROJECT VISTA – HEAD OFFICE REFURBISHMENT

A7.1 BACKGROUND

Project Vista was conceived as a comprehensive programme to refurbish the Perth head office and five metropolitan depots over a four-year period. It was approved by the Board in May 2008 subject to approval by the Authority as part of its AA2 review for expenditure to incurred on the project. Given that more than $10 million was spent in AA3 to complete this project, the Authority requested that this expenditure be examined for NFIT compliance as part of this review.

Our review has looked at expenditure on the head office building only, as much of the planned expenditure on depot refurbishment has been deferred pending implementation of a depot rationalisation programme.

The business case considered the following four options:

1. Vacating the building and moving to alternative premises;
2. Essential works including the removal of limpet asbestos from the head office building and refurbishment of all sites in scope;
3. Option 2 above plus works necessary to achieve four-star Green Star certification;
4. Option 2 above plus works necessary to achieve five-star Green Star certification.

Option 4 above was selected even though it was the most expensive of the options considered and endorsed by the Authority when it included the full Option 4 budget in its approved AA2 expenditure forecast.

The business case noted that there was potential to reduce the cost of the head office fit-out by $500,000 per floor or a total of $5 million but this would involve:

- a significant reduction in sustainable features such as furniture and materials with low volatile organic compounds and high recyclable content;
- removal of motivating features such as large, well equipped breakout areas;
- diminished overall aesthetics of the working environment; and
- a compromise on noise management features and glare reduction.

The business case described a range of benefits from the five-star Green Star upgrade. Some were quantified but many were non-financial and speculative.

A breakdown [redacted] The business case was silent on the extent to which these costs included direct internal costs or capitalised overheads.

[redacted] [redacted]

	[redacted]			[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A7.2 IMPLEMENTATION

Over the course of the project the Project Vista budget was increased on three separate occasions to a final level of $83.8 million as follows:

- In October 2008 the Board approved $2.5M to include the refurbishment of facilities at Bentley to accommodate an alliance agreement entered into with Downer EDI Engineering and Tenix Alliance to form the Power Alliance;
- In November 2010, the Board approved an additional $10.9M to address backbone services to meet safety and compliance requirements, cover project delivery administration and provide an allowance for contingencies; and
- A final Board approval was granted in March 2013 to approve an increase of $3M to address scope changes and enable completion of the project in June 2013.

We asked Western Power to provide copies of the Board papers approving these budgetary increases and copies of the October 2008 and March 2013 papers were provided. It could not provide a copy of the November 2010 paper, which had been archived. The March 2008 increase was unrelated to the head office refurbishment and the [redacted]

[redacted]

[redacted]

[18] There were two primary contractors for head office refurbishment works and this was the larger of the two.

We note that the analysis Western Power provided, as summarised at the front of this section, made no reference to an [redacted] and that the comments above suggest that by the end of the project, Western Power had lost control over project costs. The internal audit report was included as Appendix B to the Board paper but was not provided to us. Time constraints have prevented us from requesting additional information on this project or investigating cost overruns in more detail.

Table A7.2 shows the initial budget, approved budget extensions and the final costs of the two main project components.

Table A7.2: Project Vista Cost Analysis ($ million, nominal)

	Head Office	Depots	Total
Approved business case	54.53	12.87	67.40
October 2008 variation		2.50	2.50
November 2010 variation	10.90		10.90
March 2013 variation	3.00		3.00
Total amended budget	68.43	15.37	83.80
Actual cost	76.54	6.42	82.96
Budget variance	**8.11**	**(8.95)**	**(0.84)**
Budget variance (%)	**11.9%**	**(58.2%)**	**(1.0%)**

Table A7.2 indicates that the completion cost reported by Western Power for the head office refurbishment exceeded the budget finally approved by the Board for this work by almost 12% and the original business case budget by over 40%.

Western Power's head office building was awarded a five-star Green Star rating in March 2015.

A7.3 AA3 EXPENDITURE

There are inconsistencies in the information provided to us on the actual capex spent on Project Vista during AA3, as shown in Table A7.3.

Table A7.3: AA3 Expenditure on Project Vista ($ million, real 2017)

Project Closeout Report	
External costs	12.00
Internal costs	0.36
Total	**12.36**
Review Information	
Level 1	4.7
Level 2	3.7
Ground floor and basement	3.0
Lifts refurbishment[1]	2.1
Total	**13.5**

Note 1: Not part of Project Vista

A7.4 COMMENT

Western Power's closeout report for the head office refurbishment component of Project Vista reported that of the actual cost of $76.54 million, $75.39 million were external costs. Only $1.15 million (1.5%) of the reported project costs were internal costs. On this basis, we think that the project cost has been understated in that they do not fully capture internal costs. If Western Power had applied the cost allocation rules it now applies to network projects, it would have included direct internal costs, such as planning, project, and contract management costs, which we estimate to be at least 5%, as well as capitalised overheads, which are currently captured by Western Power's cost driver simple (CDS) process. If we assumed 5% capitalised overheads and CDS of 19%, the actual project cost works out to be $94.79 million.

A7.4 CONCLUSION

While much of the scope of the head office refurbishment comprised essential works, the business case proposed a quality upgrade justified largely by unquantified benefits relating to improvements in staff productivity and morale and improvements to Western Power's reputation as a good corporate citizen. This is not to suggest that the refurbishment has not delivered savings in energy and other operational costs and Western Power has provided some evidence of this. We also note that the Authority endorsed the scope when it approved the AA2 capex forecast.

In November 2010, the Western Power Board approved a 20% increase in the project budget. As we have not seen the business case for this increase we cannot comment on the drivers or the extent to which the Board or management reviewed the costs of the project prior to this approval. We think an independent review of the project scope and costs at this time should have been commissioned, but we do not know if this occurred.

The final project cost, as reported by Western Power, exceeded the budget approved by the Board by about 12% and the business case budget by 40% but these cost overruns were masked to some extent by savings made from scope reductions in work at the metropolitan depots. While some of the budget overrun is likely to have been justified, there is also evidence that Western Power lost control over the costs of the project and this contributed to the cost escalation.

The reported final cost of the project does not fully capture the internal costs of managing the project or the overheads that are normally capitalised into the cost of a project. Had these costs been included in accordance with Western Power's normal cost allocation rules, we conservatively estimate that the reported head office refurbishment cost should be approximately $94.8 million.

The efficiency test for NFIT compliance requires that the investment does not exceed the amount that would be invested by a service provider efficiently minimising costs. We are unable to reach this conclusion in respect of the total Project Vista expenditure on the head office refurbishment, but are unable to provide a recommendation on how much of this expenditure should be considered NFIT compliant. The information we have seen on how the project was managed is limited and we are not qualified to make this assessment.

Finally, we note that Project Vista is a legacy project that was initiated in 2008 and inherited by the current management and Board of Western Power.

APPENDIX B

AA3 TRANSMISSION CAPACITY EXPANSION PROJECTS THAT HAVE NOT PROCEEDED TO CONSTRUCTION

Table B1 shows transmission capacity expansion projects that were provided for in the AA3 capital expenditure forecast but have not proceeded to construction. Where the actual AA3 expenditure is negative, Western Power Western Power has reversed expenditure incurred during AA2 out of the RAB. Actual AA3 expenditure that is positive remains in the propsed AA4 opening RAB

Table B1 Approved AA3 Capacity Expansion Projects that have not Proceeded ($ 000, Real 2017)

	Driver	Project Description	Forecast AA3 Exp.	Actual AA3 Exp.	Comment
1.	Voltage	132kV capacitor bank at ST substation	1,411	-	No longer required
2.	Thermal management	132kV double circuit cable from Shenton Park to Medical Centre substations	4,831	-	Deferred but no AA4 expenditure
3.	Thermal management	132kVLine Upgrade from WT-N-CTE	3,230	-	Deferred but no AA4 expenditure
4.	Thermal management	2nd NBT 330/132kV transformer	1,188	-	No longer required
5	Voltage	90 MVAr Cap Bank at GLT 132kV	4,211	-	No longer required
6.	Supply	Albany 1 x 33 MVA expansion	6,394	-	No longer required
7.	Supply	Arkana 4th x 33MVA	8,175	-	No longer required
8.	Supply	Belmont Area	10,809	-	On hold – no AA4 expenditure
9.	Thermal management	Build EP to new CBD Sub 132kV DC cable	7,152	-	Deferred – no AA4 expenditure
10.	Supply	Build NBT to new Wanneroo East Sub DC 132kV line	18,408	-	No longer required
11.	Thermal management	Build PNJ 330kV Terminal	52,291	-	No longer required
12.	Supply	T0375276 NBT: 132 kV OHL Reinforcement	11,088	-	No longer required
13.	Thermal management	Convert SF to ST 132kV DC Bonded line to 132kV DC	1,798	-	No longer required
14.	Supply	Cook St - 1 x 80MVA	15,033	-	No longer required
15.	Thermal management	CT 330kV switchyard and KNL 330kV expansion	1,920	-	No longer required
16.	Supply	Distribution Driven Transmission Works	4,831	-	No longer required
17.	Supply	East Rockingham	2,270	-	No longer required
18.	Supply	Geraldton Terminal 132/33kV Tx	9,485	-	No longer required

	Driver	Project Description	Forecast AA3 Exp.	Actual AA3 Exp.	Comment
19.	Supply	James St Substation Stage 1	24,078	-	No longer required
20.	Supply	Joondanna Tx	2,188	-	No longer required
21.	Supply	Mandurah/Meadow Springs Area	30,592	-	No longer required
22.	Supply	Manning - 1 x 33MVA	6,137	-	No longer required
23.	Supply	Mason Rd - 1 x 33MVA	6,137	-	No longer required
24.	Supply	Murdoch 1 x 33MVA	6,657	-	No longer required
25.	Voltage	NT 330kV SVC (2 x +100MVAr blocks + +250/-120MVAr dynamic)	58,571	-	No longer required
26.	Thermal management	Amnesty 14/15	5,157	-	No longer required
27.	Supply	Rebuild Nedlands Substation - GIS	12,872	-	No longer required
28.	Supply	WGA 2nd transformer	6,355	(96)	Deferred. No AA4 expenditure
29.	Voltage	New 132 transmission line; Picton-Busselton	33,284	843	Deferred. $22,655k forecast in AA4.
30.	Supply	BUH – 4th transformer at BUH	39,315	147	Deferred. $7,847k forecast expenditure in AA4.
31.	Thermal management	JDP-WNO 81 line uprate	6,176	397	Line uprate replaced with lower cost solution
32.	Supply	Establish new zone substation in OP area	6,176	(52)	Deferred. No AA4 expenditure
33.	Supply	New CBD substation	67,788	1,059	Deferred. $73,443 forecast in AA4 but substation no longer required.
34.	Voltage	KAT: Install reactive support	24,095		
35.	Supply	NBT-WNO 81: Convert split phase to double circuit line	4,742	2	Deferred. No AA4 expenditure
36.	Supply	LDE: Install additional transformer capacity	7,503	2	Deferred. No AA4 expenditure
37.	Supply	ZTS: Establish zone substation	29,802	12	Deferred. No AA4 expenditure
38.	Thermal management	Thermal ERA FD changes	47,785	-	No longer required
39	Supply	Wangara – 3rd transformer	1,241	-	No longer required
40	Supply	Willeton – 2nd transformer	6,150	-	No longer required
Totals			**597,326**	**2,314**	

Source: Western Power's variance analysis