Appendix A: Capital and Operating Expenditure Report

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westernpower

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Contents

1 Introduction

The purpose of this appendix is to provide further detail regarding our forecast expenditure for the third access arrangement period (AA3). In particular, this appendix provides more detailed information on:

- the drivers for investment
- the breakdown of forecast expenditure by activity for AA3
- the specific works that are forecast to be undertaken
- compliance of AA3 forecast capital expenditure with section 6.52 (b) of the *Electricity Networks Access Code 2004*[1] *(Access Code)*

In order to operate and maintain the Western Power Network and expand capacity in line with customer's requirements, we will spend $8.523 billion of transmission and distribution capital and operating expenditure in AA3. Of this, $0.958 billion will be contributed by individual customers.

This document is structured in accordance with the expenditure categories defined in the *Authority's Guidelines for Access Arrangement Information* (AAI Guidelines). Our forecast operating and capital expenditure for the AA3 period are shown in Table 1 and Table 2, respectively.

Table 1: AA3 forecast operating expenditure

Category of expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Transmission operating expenditure - Chapter 3 of this appendix						
Maintenance	44.5	46.5	49.0	51.6	55.3	246.9
Operations	25.6	26.8	28.5	30.1	32.3	143.3
Other	13.9	7.2	11.0	14.0	20.1	66.3
Transmission total	**84.0**	**80.6**	**88.5**	**95.7**	**107.7**	**456.5**
Distribution operating expenditure - Chapter 4 of this appendix						
Maintenance	218.8	229.3	242.0	243.8	262.1	1,196.0
Operations	42.3	43.3	46.5	50.3	54.7	237.1
Customer services and billing	34.3	36.1	38.1	40.0	42.0	190.4
Other	8.0	10.0	10.2	10.4	10.9	49.5
Distribution total	**303.5**	**318.7**	**336.8**	**344.4**	**369.7**	**1,673.0**
Corporate operating expenditure - Chapter 5 of this appendix						
Other	108.9	110.7	115.4	122.4	126.7	584.1
Less non-revenue cap services	18.0	18.5	19.4	20.4	21.8	98.1
Operating expenditure to be recovered through reference tariffs	**478.3**	**491.4**	**521.2**	**542.2**	**582.4**	**2,615.5**

[1] Available at: http://www.energy.wa.gov.au/cproot/2773/2/Electricity%20Networks%20Access%20Code%202004%20(2011%20version).pdf

Table 2: AA3 forecast capital expenditure

Category of expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Transmission capital investment - Chapter 6 of this appendix						
Growth	290.6	206.3	290.9	440.7	326.8	1,555.3
Asset Replacement	30.8	33.9	34.8	35.4	37.8	172.6
Regulatory Compliance	14.3	17.3	24.8	31.5	32.8	120.7
Service Improvement	14.4	12.2	13.5	19.3	19.4	78.8
Transmission total	**350.2**	**269.7**	**363.9**	**526.9**	**416.7**	**1,927.3**
Distribution capital investment - Chapter 7 of this appendix						
Growth	338.5	348.5	369.9	374.8	386.7	1,818.3
Asset Replacement	217.5	264.3	257.3	260.6	244.9	1,244.6
Regulatory Compliance	100.7	107.3	110.4	79.3	87.6	485.3
Service Improvement	5.5	6.6	7.7	4.8	8.2	32.9
Distribution total	**662.3**	**726.7**	**745.3**	**719.4**	**727.4**	**3,581.1**
Corporate capital investment - Chapter 8 of this appendix						
Other total	**76.5**	**74.2**	**49.5**	**52.1**	**49.1**	**301.4**
Less contributions	207.9	193.4	182.8	184.6	188.8	957.6
Capital investment to be recovered through reference tariffs	**881.0**	**877.3**	**975.8**	**1,113.8**	**1,004.3**	**4,852.2**

1.1 Nature and categorisation of costs

Section 3.8 of the AAI Guidelines specifies the categories that are to be used to classify capital and operating expenditure in the regulatory financial statements (see Figure 1). We have used these expenditure categories as the basis for describing the activities and forecasts associated with the AA3 operating and capital expenditure portfolio as set out in chapters 7 and 8 of the AAI respectively.

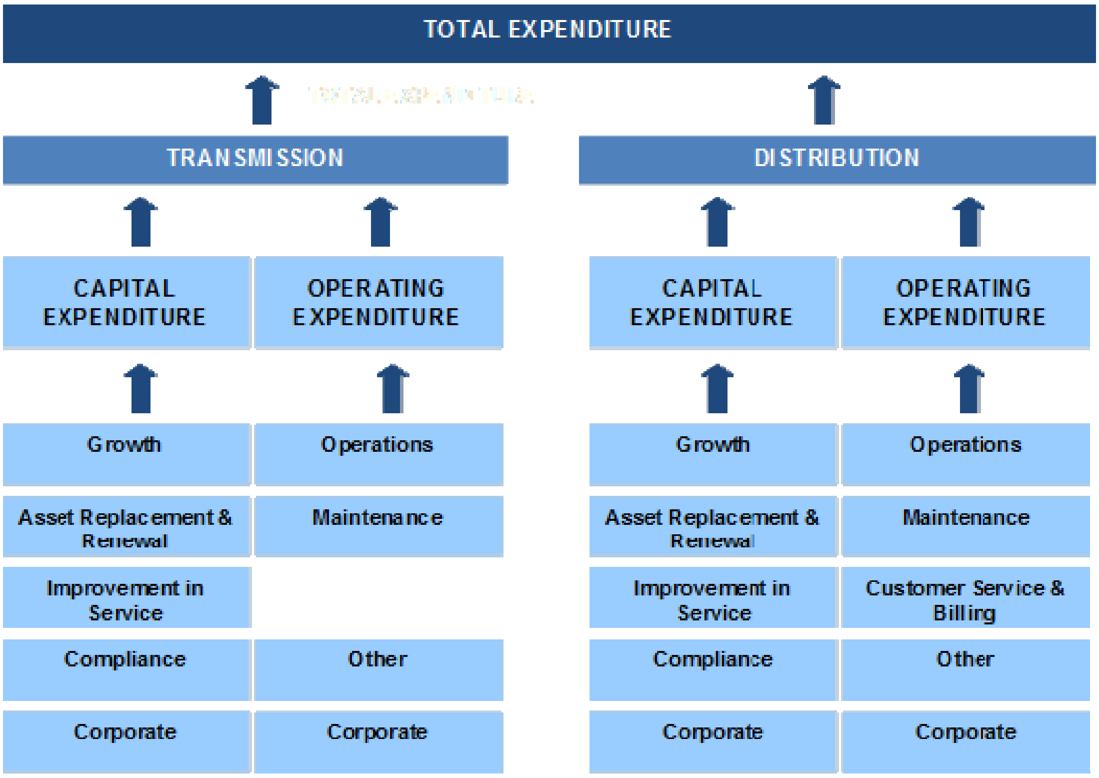

Figure 1: High level structure of capital and operating expenditure categories

We have discretion to break these high level expenditure categories down further for internal reporting purposes.

We have reviewed our internal categorisation of costs for AA3 to ensure that the lower level 'regulatory categories' remain informative and relevant to our underlying cost base. As a result, we have created three new regulatory categories and made a number of minor changes to the activity allocations between existing regulatory categories. These changes commenced in 2011/12 and include:

- combining the transmission capacity expansion and generation driven capital investment regulatory categories – these regulatory categories were originally created to distinguish between expansion driven by load and expansion driven by generation. However, this distinction is no longer meaningful given Western Power's revised long term planning approach which seeks optimal network solutions to meet the combined requirement from load and generation (for example: the Mid West Energy Project)
- creating smart grid[2] regulatory categories for capital and operating expenditure – since smart grid activities commenced in 2009/10, capital investment has been included as part of the distribution regulatory compliance category and operating expenditure has been included in the non-recurring operating expenditure regulatory category. Commencing 2011/12, a new regulatory category has been established to reflect the significant forecast increase in activity and resulting expenditure and to ensure that comparisons with historical expenditure can be maintained
- creating a new operating expenditure regulatory category for the guaranteed service level payment scheme – payments have historically been included in the business

[2] Smart grid related capital investment is in 'asset replacement and renewal' and operating expenditure is in 'operations' regulatory categories.

support regulatory category. To improve transparency and monitoring a new regulatory category has been created within customer services and billing

- creating a new operating expenditure regulatory category for 'Design and Estimating – distribution quotations': expenditure associated with quotations for customer applications that do not proceed were previously recorded under the business support regulatory support. A new regulatory category has been established within customer services and billing to improve transparency of costs and to ensure that comparisons with historical expenditure can be maintained
- renaming the distribution operating expenditure 'reliability improvement' regulatory category to 'reliability operations' – this regulatory category contains operational activities for maintaining the serviceability of automation equipment in the AA3 period. It has been renamed to remove doubt that this category contains expenditure that would provide more than that required to maintain service levels
- renaming the category 'miscellaneous network' services to 'non-revenue cap services' to better align with our definition of these services in the AAI – this category has been renamed to remove doubt that this category contains expenditure that is not included within revenue cap calculations

In addition to the expenditure associated with transmission and distribution network and corporate covered services, we also incur costs (and receive revenue) to provide:

- system operation activities on behalf of the Independent Market Operator. These costs are not included in this submission but form part of 'System Management's Allowable Revenue' application under clause 2.23.3(c) of the *Market Rules*, dated 31 March 2010
- unregulated services on a fee per service basis. These services are not associated with the provision of covered services and comprise sale of materials, IT support services and construction of electrical infrastructure not part of the Western Power Network

This appendix does not cover the expenditure associated with system operation activities on behalf of the Independent Market Operator or unregulated services.

1.2 Explanatory notes

For the purpose of this submission, all historical expenditure has been aligned to the activity and regulatory categories of the AA3 forecasts. For this reason, historical expenditure by regulatory category will not necessarily reconcile[3] to the regulatory financial statements.

All monetary amounts presented in this report are expressed in $ million real at 30 June 2012 and apply to financial years from 1 July to 30 June unless otherwise stated. In addition, tables of figures within this document may not add due to rounding.

References to a chapter in the AAI, means that chapter included in the *Access Arrangement Information for 1 July 2012 to 30 June 2017*.

[3] Total capital and operating expenditure will reconcile to the regulatory financial statements. Expenditure by category may have been altered to better align historical trends with current cost allocations as outlined in section 1.1. This complies with section 4.3.2 of the AAI Guidelines which require 'consistency with previous years' allocation policies … and prior year figures restated accordingly'.

1.3 Structure of this appendix

This document is structured as follows:

Chapter 1 – provides a summary of total expenditure, nature and categorisation of costs, amendments to cost allocation and categorisation since commencement of the second access arrangement period and explanatory notes necessary to navigate financial information contained within this document.

Chapter 2 – provides an outline of the current size and state of the distribution and transmission systems within the Western Power Network, an overview of the network planning methods, network constraints and asset management approach relied upon to derive forecasts of operating expenditure and capital investment for the AA3 period.

Chapters 3 and 4 – provide an overview of the drivers, activities and step changes in obligations or functions for each category of AA3 **operating expenditure** for the **transmission** and **distribution** system, respectively.

Chapter 5 – provides an overview of the drivers, activities and step changes in obligations or functions for each category of AA3 **corporate operating expenditure**.

Chapter 6 and 7 – provide an overview of the drivers, activities and step changes in obligations or functions for each category of AA3 **capital investment** for the **transmission** and **distribution** system, respectively.

Chapter 8 – provides an overview of the drivers, activities and step changes in obligations or functions for each category of AA3 **corporate capital investment**.

2 Approach to network planning and asset management

This chapter provides context as to how we have developed our forecast expenditure for the AA3 period. It comprises:

- an outline of the current size and state of the distribution and transmission systems within the Western Power Network
- an overview of the network planning methods and network constraints relied upon to derive AA3 forecast growth-related capital investment
- an overview of the asset management approach relied upon to derive AA3 forecast expenditure on operations and maintenance activities and non-growth related capital investment

This chapter should be read in conjunction with chapters 7 and 8 of the AAI which outline our forecasting methods and expenditure at a high level.

2.1 Western Power Network

The assets that form the transmission elements of the Western Power Network can be grouped into three broad categories:

- *primary lines and cable assets* - poles, towers, conductors and cables with voltages ranging from 6.6 kV to 330 kV. These are the physical assets which convey power over long distances
- *primary substation assets* - power transformers, circuit breakers and other primary plant located in terminal and zone substations, with voltages ranging from 6.6 kV to 330 kV. Primary assets enable the management of power flows from generators to the distribution feeders that supply most of our customers[4]
- *secondary substation assets* - relays, protection equipment, Supervisory control and data acquisition (SCADA) and communications equipment, and power supplies and batteries needed to power the secondary equipment. Secondary assets protect and control primary assets

Table 3 shows the number of key primary and secondary assets currently in service within our transmission network.

[4] The number of customers connected to the transmission network make up less than 0.01% of Western Power's customer base.

Table 3: Populations of key Western Power Network transmission assets[5]

Asset group	Number
Primary plant units	22,781
Terminal and zone substations	152
Power transformers	341
Circuit breakers	2,800
Overhead lines circuit length	7,228 km
High voltage cable	25 km
Structures and poles	40,805
Secondary assets	29,859

In comparison to transmission, larger numbers of smaller assets make up the distribution network. The assets that form the distribution elements of the Western Power Network range in voltage from 240 V to 33 kV. Power flows through distribution feeders to supply most of our customers. The high level view of populations of asset classes on the distribution network is provided in Table 4 below.

Table 4: Populations of key Western Power Network distribution assets[6]

Asset group	Quantity
Overhead conductor	68,561 km
Underground cable	20,375 km
Distribution poles	751,725
Distribution transformers	64,587
Distribution substations	13,731
Customer connections (power meters)	942,893
Streetlights	230,375

2.1.1 Current state of the network

Similar to major networks in the eastern states, the Western Power Network was largely constructed in the 1960s and 1970s, followed by a period of subsistence investments to connect new customers and generators. Because of this, many of our assets are reaching the end of their serviceable live and will require replacement over the next five to ten years.

We generally replace our assets based on condition rather than age. However, age provides an indication as to when assets will need to be replaced. We expect the required future volumes of asset replacement to mirror the growth in the number or length of populations of assets.

Each of our assets is assigned an expected life based on the industry's and our knowledge of similar assets. The expected life and average age of different types of transmission and distribution assets, as at 30 June 2011, are illustrated in Figure 2 and Figure 3, respectively.

[5] Data as at 1 January 2011. The power transformers population excludes those owned by customers.
[6] Data as at 1 January 2011.

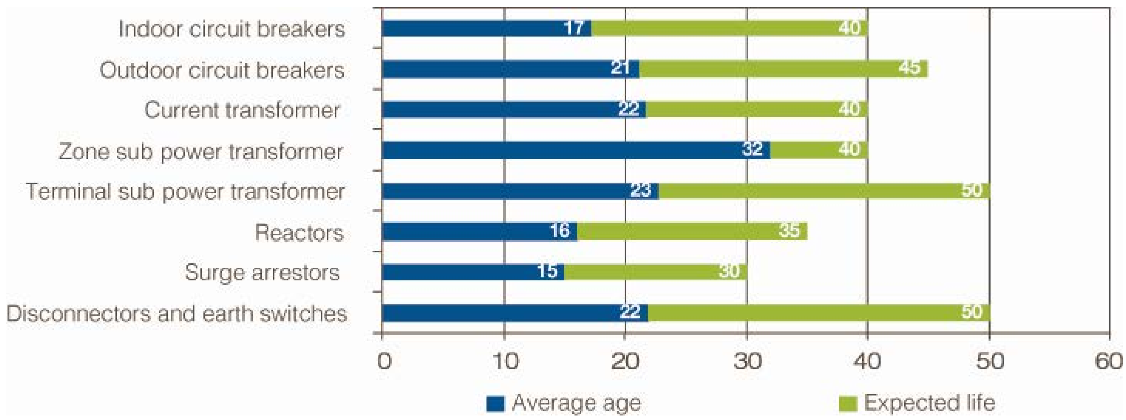

Figure 2: Age profile of Western Power's transmission network (2010/11)

Overall, the average age relative to expected life for transmission assets is approximately 42%, with zone substation power transformers having the highest ratio (80%). For distribution assets, the average age relative to expected life is 52%, with drop out fuses having the highest ratio (77%).

Figure 3: Age profile of Western Power's distribution network (2010/11)

We rely on a suite of standardised measures to determine the overall *health* or *condition* of assets and hence the trigger point when additional investment or maintenance may be required. The key network performance metrics comprise:

- *safety* – measures of network and public safety including asset initiated electric shock incidents and asset initiated fires due to asset failure
- *growth* – measures of peak demand, energy consumption and customer numbers as discussed in chapter 6 of the AAI
- *service* – measures of network reliability, security and customer service including measures discussed in chapter 3 and chapter 5 of the AAI, the transmission line integrity index, transmission substation integrity index, distribution pole integrity index and wires down performance indicators

Performance metrics for each asset class are contained in the Network Management Plan which is provided as Appendix L: Network Management Plan.

Monitoring and management of these performance indicators during AA3 will ensure we achieve our expenditure objectives:

- *safety* – reduce public safety risk associated with asset failure
- *growth* – network capacity is sufficient to facilitate ongoing growth and improved system security that will decrease likelihood of long-duration widespread outages
- *service* – service levels are maintained at expected levels, or are improved only where customers value them

Asset initiated electric shock incidents

The measure of asset initiated electric shock incidents is the number of shocks experienced by members of the public that are reported as being caused by Western Power or Western Power assets[7]. This measure has been worsening over the AA2 period (see Figure 4). The most significant contributor to electric shocks during AA2 has been overhead customer service connection failures[8].

In AA3 we will reduce the likelihood of asset initiated electric shock incidents caused by Western Power primarily through the replacement of overhead service connections. Section 7.3.1.2 provides an overview of our overhead service connection replacement program.

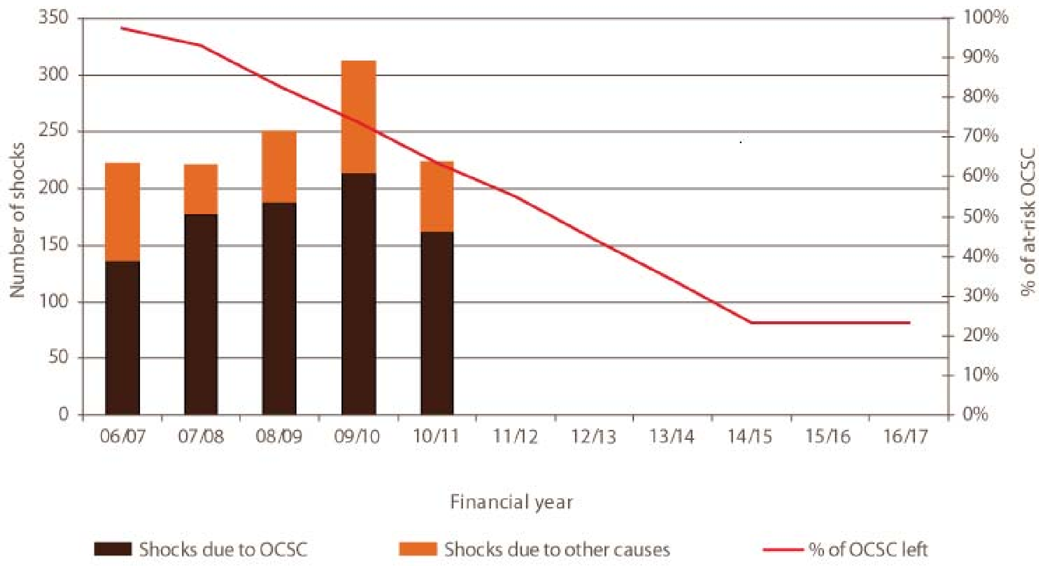

Figure 4: Electric shocks caused by Western Power

Asset initiated fires

Our assets can start fires via asset failure or from external environmental causes, for example bird/animal, vegetation encroachment or storms. We measure these external causes separately. The performance indicator for the number of asset initiated fires due to asset failure includes incidents due to wires down, poles down, pole top fires, clashing

[7] Not all electric shocks are attributable to Western Power, for example, in 2009, 59% of the 644 shocks reported to Energy Safety were caused by customer installations.
[8] Other causes of electric shock are due to faulty underground service connections in pillars, neutral voltage rise on street LV networks due to faulty connections and contact with live conductors.

conductors and distribution protection equipment failures. It excludes fires caused by the external environment.

The primary root causes of increases in incidents in AA2 were pole top fires and equipment failure. However, the increase can also be partially attributed to improve reporting of the number of incidents.

In AA3 we will reduce the likelihood of asset initiated fires due to asset failure through targeted investment in bushfire mitigation, specifically pole top replacement. Section 7.3.1.1 provides an overview of our bushfire management program.

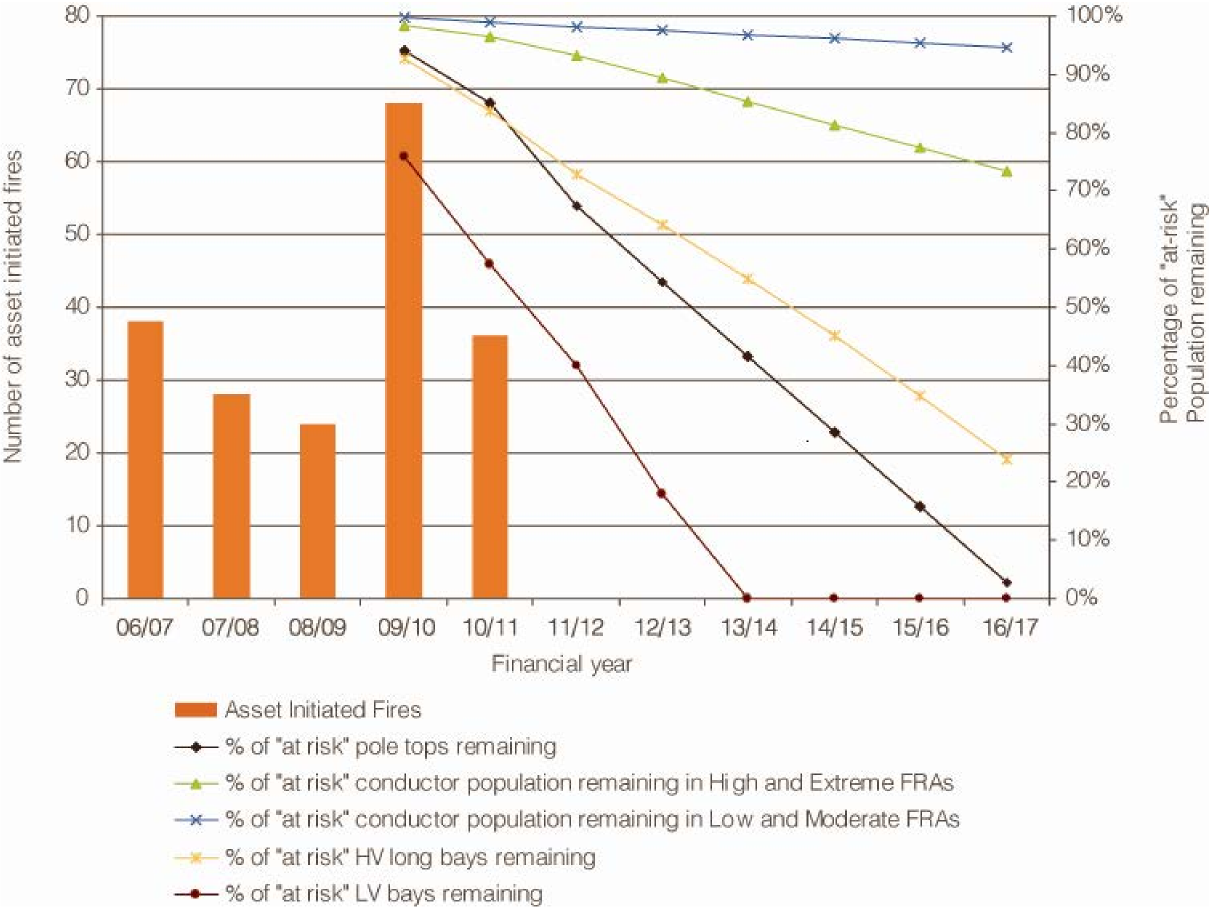

Figure 5: Asset initiated fires

Transmission line integrity index

The transmission line integrity index is a measure of the number of faults per 100 circuit km of power lines at voltages of 66 kV and above. This measure has declined over the AA2 period (see Figure 6) as a result of:

- an increase in acts of vandalism
- an increase in vehicle / asset collisions
- contribution of summer lightning storm activities

In AA3 we will continue the transmission pole management plan to maintain the current condition and performance of transmission lines and associated assets. Sections 3.1.1.6, 3.1.1.7, 3.1.2.2, 6.4.1.1 and 6.4.1.3 provide an overview of forecast capital and operating expenditure on transmission lines.

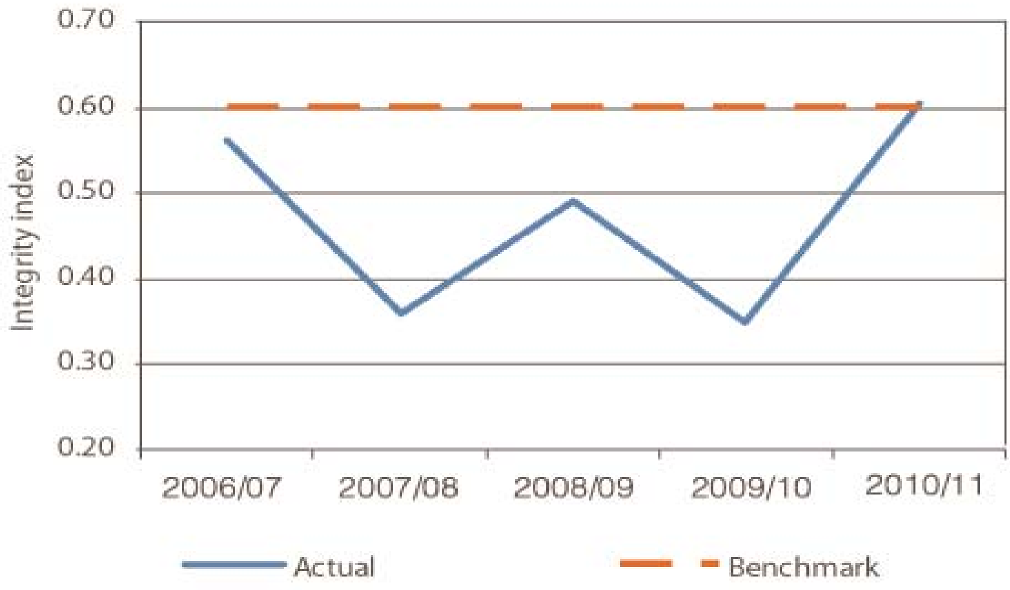

Figure 6: Transmission line integrity Index

Transmission substation integrity index

The transmission substation integrity index is a measure of the number of defects over all substation primary plant units. This measure has been deteriorating over the AA2 period (see Figure 7) largely as a result of sulphur hexafluoride (SF_6)[9] leaks from circuit breakers which has negatively impacted on performance. In AA3 we will target maintenance of substation primary plant to maintain current levels of performance. Sections 3.1.1.2, 3.1.1.5, 3.1.2.4 and 6.2.1.1 provide an overview of forecast capital and operating expenditure on transmission substation assets.

[9] A gaseous dielectric used in high voltage electrical equipment both as an insulator and as an arc quenching medium. The US EPA notes that SF_6 is a potent greenhouse gas with a global warming potential that is 23,900 times greater than that of carbon dioxide (CO_2). It is also very persistent in the atmosphere with a lifetime of 3,200 years

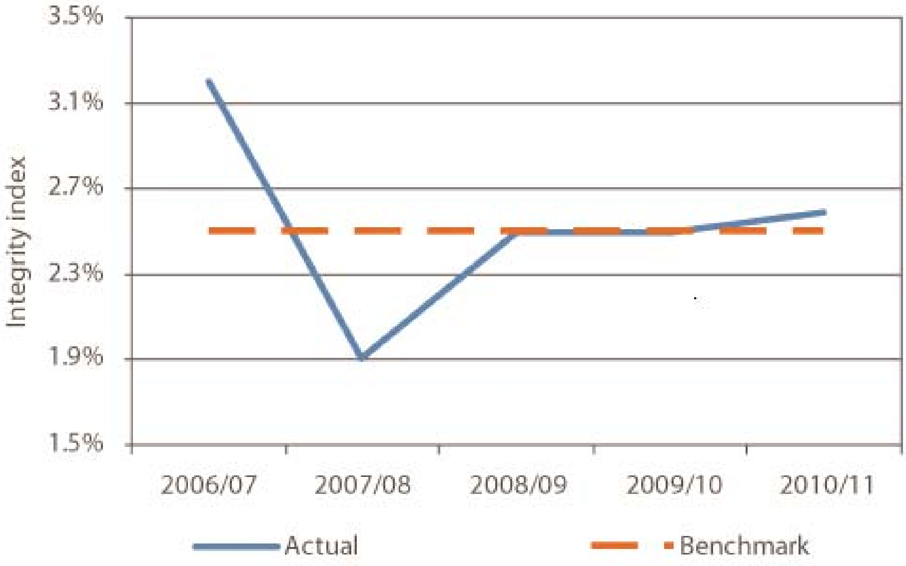

Figure 7: Substation integrity index

Pole integrity index

The standard industry performance measure for poles are the transmission pole integrity index and the distribution pole integrity index, which report the number of unassisted pole failures per year, per 10,000 poles. The pole integrity indexes are an indicator of the health of the pole population and are compared against industry performance.

Our transmission pole integrity index was 5.69 for 2010/11, more than 5 times the industry benchmark of 1.0. Within the last twelve months the transmission pole integrity index has deteriorated significantly. This is largely due to increased summer storm and lightning activity during January and February 2011 which resulted in over 30 transmission poles being knocked over. This is more poles than we usually lose in an entire year.

We are targeting a step change in the number of pole replacements and reinforcement to reduce the unassisted pole failure rate (see Figure 8) to meet the target of transmission pole integrity index of 1.0 by the end of AA4. Section 6.4.1.1 provides an overview of forecast capital and operating expenditure on transmission poles.

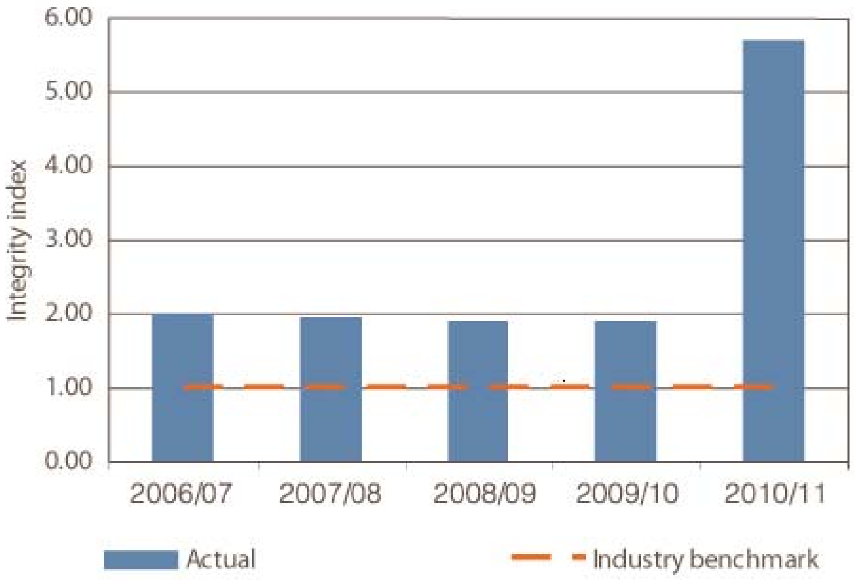

Figure 8: Transmission pole performance

With the improved identification of unserviceable poles, increased pole replacement rates and better information management, the distribution pole integrity index has improved since the AA1 period, despite deterioration in performance in 2010/11 as shown in Figure 9. Western Power's failure rate is the highest in Australia.

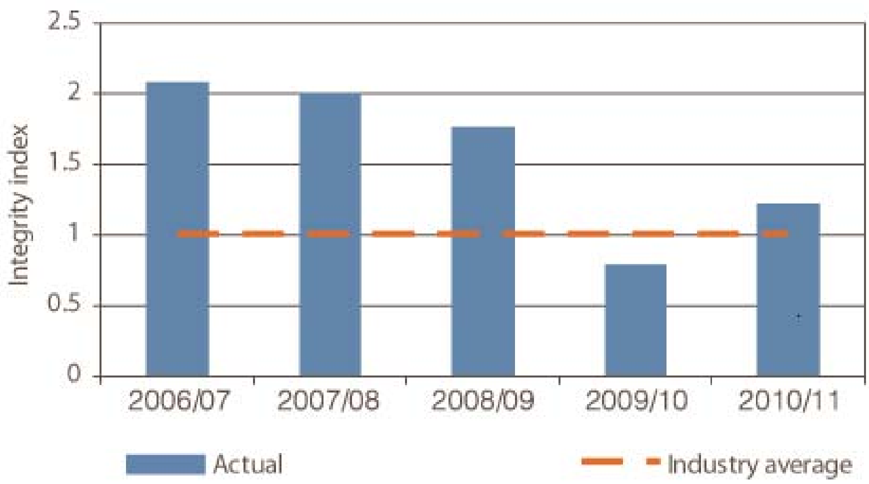

Figure 9: Distribution pole integrity index

In AA3 we will continue to invest in pole replacement, reinforcement and maintenance to improve our pole integrity index, targeting industry standard levels by AA4. Sections 4.1.1.1, 4.1.1.3, 4.1.2.2 and 7.2.1.1 provide an overview of forecast capital and operating expenditure on distribution poles.

Distribution wires down performance indicator

The distribution wires down performance indicator measures the number of wires down incidents on the Western Power Network. All overhead electricity networks carry an inherent public safety risk through the potential for conductors to fall or clash due to degrading conductors, equipment failure, extreme weather or other external factors. The greatest hazard is falling wires or clashing conductors which leads to the potential, under certain conditions, for the conductors to spark and ignite fire or cause an electric shock.

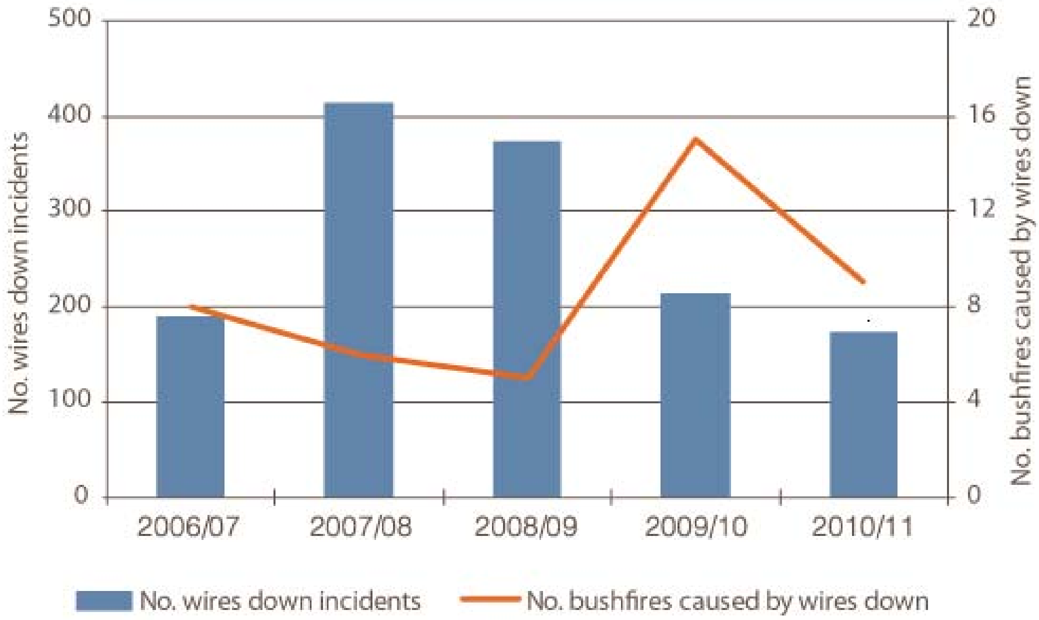

Figure 10: Wires down performance indicator

Figure 10 shows the reduction in wires down over the AA2 period with the introduction of a proactive rather than reactive replacement regime. However, the number of bushfires caused by wires down in medium and low bushfire areas has been increasing. In AA3 we will extend our focus to targeting a reduction in the number of wires down incidents in medium to low bushfire risk areas where the majority of AA2 incidents occurred. Sections 4.1.1.3, 4.1.1.4 and 7.2.1.2 provide an overview of forecast capital and operating expenditure on our conductors.

2.2 Network development planning

As the electricity network planner for the Western Power Network, we are responsible for delivering network development plans that ensure there is sufficient capacity to transmit power from power stations to load centres then to individual customers and that this is achieved in the most cost effective way.

The transmission network development plan identifies a suite of projects and is provided at Appendix O: Transmission Network Development Plan. Each of the projects within the transmission network development plan can be clearly associated with particular drivers (such as new load or generation connection), triggers for augmentation (for example insufficient thermal capacity on transmission lines following new load or generation connection) and timing.

The Transmission Network Development Plan describes emerging network issues and potential solutions for the transmission and distribution networks and is developed or refreshed annually as part of the annual planning cycle. The integrated transmission and distribution planning approach incorporates:

- load and generation scenario based forecasting, which are described further in sections 2.2.1 and 2.2.2, respectively
- in-depth system analysis and issue identification
- extensive investigation into both network and non-network options
- determination of optimised development plans for up to 10 years
- scenario-based grid vision plans beyond 10 years
- robust project development and sponsorship

We apply risk management principles when developing the network development plan and focus on balancing network costs against the impact of unreliable, insufficient or poor quality power supplies on customers.

The network development plans are developed through consideration of a number of contributing factors, including:

- *Technical Rules*[10]: comprising the network planning criteria and technical requirements for plant connected to the network
- *load and generation forecasts*: developed from observed historical trends, taking into account projections of state economic growth and customer connection enquiries
- *network management plans*: based on condition assessment of the network to ensure that it will continue to provide safe and reliable service (see Appendix L: Network management Plan). Condition assessments drive the asset replacement and maintenance activities
- *Western Power's commercial objectives*: the network development plans are developed in light of various drivers and include the normal commercial objectives of any business, as required for Western Power under the *Electricity Corporations Act 2005*. In addition, the regulatory environment means our capital investment needs to satisfy the Regulatory Test (where applicable) and be economically justifiable under the new facilities investment test

These inputs are used in the network analysis to ensure each network element satisfies a number of technical criteria so that:

- each individual network element is operated within its design limits. This requires voltage and power transfer for each asset to be assessed under a wide range of potential conditions, including for example modelling the effect of faults on the network. Failure to meet design specifications can result in malfunction or damage to customer equipment, while exceeding power transfer limits creates potential

[10] Available at: http://www.erawa.com.au/2/156/48/electricity_access__technical_rules.pm

safety hazards and reliability issues arising from the failure of network equipment due to overloads

- the network can withstand credible faults and unplanned outages. A fault is considered credible if it is considered to have a reasonable probability of occurring given the prevailing circumstances. If there is a credible fault or unplanned outage, all plant must still operate within its design limits and the network must continue to deliver the required performance
- quality of supply is maintained to the appropriate standards. Quality of supply is a term that embraces voltage, frequency and other technical aspects of power supply
- potential for future growth is adequately provided for, where economically viable to do so, ensuring that Western Power's electricity network facilitates economic development
- environmental and social impacts are responsibly managed

We undertake detailed system studies for a variety of load and generation scenarios to meet these technical criteria and perform investigations to capture network issues and associated drivers.

2.2.1 Load scenario planning

Western Power's annual peak demand forecast provides crucial input into developing plans for expanding the network. By monitoring and planning for peak demand, we ensure the network maintains its ability to provide reliable supply under the most strenuous of load demand conditions.

Since 1995, the Western Power Network has consistently demonstrated a summer peaking network. This means that in each year the summer peak load has consistently exceeded the winter peak load requiring Western Power to monitor and forecast the summer demand load growth. The key contributor to this is the increased use of air conditioning systems. This has had a dramatic impact on the size and duration of these peaks, which are becoming increasingly higher for shorter periods of time.

The primary objective of our peak demand summer forecast is to determine the load growth at each substation. This identifies the specific geographical areas where we expect load to exceed the present capacity. A clear understanding of this key network expansion driver is a crucial step in the planning process. The process enables Western Power to determine the most economically efficient option from among the most technically feasible solutions in order to resolve the capacity constraints.

We use the coincident peak forecast to determine the total system load demand growth to use in transmission network studies. These studies identify transmission network constraints and possible reinforcement options. The non coincident peak forecast determines the individual substation peak load demand growth we use to plan for reinforcement of substation capacity.

As discussed in chapter 6 of the AAI, the peak system demand increased by 147 MVA per annum from 1998/99 to 2009/10 and is projected to increase by 146 MVA or 3.2% per annum during AA3. Importantly, this projected growth varies significantly across the regions. For example, the peak demand is projected to increase by 0.3% per annum in the country east region and by 3.7% per annum in the metro north region.

2.2.2 Generation scenario planning

We plan for the connection of generation to the Western Power Network by performing studies on the proposed generation connections to determine whether any network augmentations are required.

Western Power's transmission planning responds to drivers triggered by expected growth in peak demand and the expected connection of new generation. The long lead times required to obtain environmental approvals, funding and regulatory approvals for new transmission lines often allows generation to develop more rapidly than transmission lines. Waiting for firm generation proponents prior to commencing planning studies runs the risk of unwarranted delays in connecting new generation.

We therefore engage an external market modelling consultant annually to develop a number of generation scenarios to understand how different generation scenarios might drive network development[11]. We use this information in conjunction with network access applications to help identify the long-term target networks for different load and generation development scenarios.

We then examine the long-term target network required for each scenario to determine commonality in network development. A robust plan is one that positions the network to accommodate a range of uncertain futures with optimised investment. Transmission line route and substation site selection consider both the immediate drivers and the expected future drivers in terms of both demand and generation. Work commences on line route selection and purchase of substation sites before they are required to preserve longer term solutions to network issues. The actual network expansion is triggered once there is sufficient certainty to justify the projects.

Developments in Western Australia in the next decade are highly uncertain with any changes to the factors in the scenario model potentially changing the priority of the scenarios. Western Power's external market modelling consultant, ROAM Consulting, assigned relative probabilities to each generation planting scenario. The most significant factors for variations between scenarios were the assumptions surrounding:

- level of ambition of Australia's carbon price trajectory – at the time of modelling there was significant uncertainty as to when a carbon price would be introduced, the level of the carbon price and its future trajectory
- demand growth – for this reason, we model two growth scenarios (central or expected and high)
- availability of gas for electricity generation – if there is aggressive growth in the development of LNG export facilities, it could be difficult for new gas-fired generation to obtain gas at a competitive price, encouraging new projects to use other energy sources
- wind ambition – the Western Power Network has excellent wind resources, which has attracted significant interest in wind generation development. However, as an isolated grid, there are limitations on the quantity of wind generation that can be accommodated without changes to various market rules and other technical factors. The amount of new wind generation is dependent on the ambition to overcome these factors

We have used the scenario to develop the AA3 capital investment forecast assumes a central growth load forecast, 15% carbon reduction trajectory[12] and a low level of wind

[11] ROAM Consulting was engaged to do this for the 2010/11 and 2011/12 network development plans.
[12] The Australian Government has subsequently indicated that it is committed to a 5% carbon reduction trajectory, although it has not yet been legislated. Western Power notes that if there is a 5%

ambition. Table 5 shows the generation planting scenario used. This table includes all the new generation to be added to the network and the year of the addition. The fuel type and general location of the generation is also included in the table.

Table 5: Forecast generation planting

Year	Forecast non-renewable generation	Forecast renewable generation	Forecast demand side management
2013-14	Muja (200 MW, coal)	Collgar (206 MW, wind)	50 MW
2014-15	Merredin (73 MW diesel) Coolimba (356 MW OCGT)		50 MW
2015-16		Badgingarra (130 MW wind) Nilgen (132 MW wind) Mingenew (45 MW solar thermal)	
2016-17		Carnegie (5 MW wind) Collgar (30 MW wind) Millyeanup (55 MW wind) Newworld (4 MW geothermal) Kalgoorlie (2 MW solar PV) Cervantes (40 MW wind)	77 MW
2017-18		Grasmere (14 MW wind) Dandarang-Yandin (389 MW wind)	
2018-19	Centauri (166 MW OCGT)	Augusta (50 MW wind) Mingenew (45 MW solar thermal)	
2019-20	Kwinana (99 MW OCGT)	Mumbida (90 MW wind)	
2020-21		Dandarang-Waddi (198 MW wind)	

2.2.3 Transmission emerging issues

The Western Power Network is a highly-meshed inter-connected 330 kV and 132 kV network. Historically generation plant in the Western Power Network was located in the south west due to favourable coal resources. There is comparatively little base load generation elsewhere so the majority of power supply is transferred from the south west to the major load centres. A strong 330 kV transmission system provides a backbone for the bulk transfer of electricity to strategic points in the network, including supply to areas north of the metro region.

In order to improve the overall reliability of the network the 330 kV transmission system has been developed in parallel with the underlying 132 kV system. The 132 kV network also extends from the south west, through the metro region to the north of the Western Power Network, creating a highly meshed 330 kV and 132 kV corridor. For many years this meshed network provided a number of operational and reliability benefits. However, rapid load growth over the past five years has utilised the capacity on the underlying 132 kV network. Given its meshed configuration, coupled with rapid load growth (particularly in the north), the 132 kV system is now providing considerable supply to northern areas and is operating at near maximum capability under high demand conditions. This occurs at the same time as the 330 kV system supplying the north operates with considerable spare capacity. Similar issues are

carbon reduction trajectory rather than a 15% carbon reduction trajectory, the number of customers at risk of a loss of supply, will be reduced rather than augmentation projects deferred.

also emerging in the south, where the 132 kV network is effectively constraining the 330 kV transmission system transfer capability.

In addition to the limitations imposed on 330 kV transfer capability, the meshed nature of the existing network also increases fault levels throughout the system. Over the years new generation has pushed fault levels to the capability of primary plant and protection systems in a number of areas. Currently, a number of major terminal stations have fault levels which reflect maximum equipment ratings.

Any generation connected to the 132 kV network in the metropolitan area will likely trigger fault level issues, particularly if connected in close vicinity to existing large terminals. The fault limitations currently constrain the connection of new generation in the metropolitan area to the 330 kV network and enforce restrictions on the operation of some transmission plant when all existing generating units are in service.

Adequately rated plant is both a matter of safety and prudent asset management. Excessive fault currents caused by fault conditions can damage under-rated plant and can cause damage to other plant and personnel in the immediate vicinity if not adequately addressed.

We have developed a strategy to address the bulk transmission system issues by not operating the 330 kV and 132 kV transmission systems in parallel at strategic points in the network. This would improve the utilisation of the 330 kV transmission network for bulk power transfer, whilst offloading the underlying 132 kV network and reducing fault levels. The primary options largely involve reconfiguration of the 132 kV transmission network to:

- reduce fault levels across the system
- improve bulk power transmission flows on the 330 kV network
- allow existing generation to operate unconstrained and facilitate connection of new generation to manage future 132 kV fault levels
- establish load centres associated with new 330/132 kV terminal substation sites to significantly relieve congestion on the 132 kV system

2.2.3.1 Supply issues

Supply issues emerging in the Western Power Network include:

- shortfall of zone substation power transformer capacity
- thermal constraints on distribution networks limiting the capability to supply loads or transfer loads between zone substations
- voltage regulation constraints on long distribution feeders limiting the ability to connect new loads
- voltage imbalance due to disproportionate loading on our single phase distribution network

We are in a unique position relative to our peers. As the planner for both the transmission and distribution network, we are able to determine the optimum solution to address these issues, whether this is a transmission network solution, distribution network solution or non-network solution.

For planning purposes, the Western Power Network is divided into five planning regions. This separates the metropolitan and country regions from each other but still provides optimal integrated planning for Western Power. The Metro Region is further divided into four planning sectors: CBD, Metro North, Metro South and Metro East.

Metro Planning Region

The Metro Planning Region extends as far north as Guilderton, as far south as Dawesville and east to Chidlow. Overhead distribution networks dominate the outer fringes of the metro planning region, but as subdivisions on the outskirts expand over time, the network infrastructure is changed to an underground network.

The overhead networks on the outer fringes tend to be long feeders and suffer from voltage constraints and reliability issues, predominately in the north of the Metro Planning Region and, to a lesser extent, in the south of the Metro Planning Region where the mean feeder lengths are relatively long. The underground and overhead networks within the urban fringes experience thermal constraints as they strive to accommodate load growth and new developments. This is compounded by restrictions on feeder exit cable ratings caused by feeder congestion around the zone substations.

CBD

The feeders in the CBD area operate at 11 kV[13], are relatively short because of the high load density and suffer from thermal constraints primarily caused by feeder congestion out of the zone substation. In addition, the placement of large loads clustered together throughout the CBD makes it difficult to transfer load effectively and forms part of the challenge for future planning issues and connection of new large customer block loads.

Metro North

There is sufficient overall capacity in the 6.6 kV and 22 kV (A) networks to cater for the forecast electrical demands over the AA3 period. However, there are constraints in specific parts of the network, namely Nedlands and Shenton Park zone substations, due to ageing power transformers, and the power transformer capacity is forecast to be exceeded at Hadfields and Henley Brook zone substations.

There is insufficient capacity in the 11 kV network to cater for the forecast electrical demands over the AA3 period, with the capacity at Osborne Park and Manning Street zone substations forecast to be exceeded by mid way through AA3. In addition, there are capacity constraints that limit the ability to transfer significant portions of load between zone substations and there are thermal constraints on the distribution exit cables.

In AA3 consistent urban load growth in the 22 kV (B) network means the load forecast is expected to exceed the power transformer capacity at Mullaloo, Padbury and Lansdale.

Metro South

There is sufficient overall capacity in the 22 kV network to cater for the forecast electrical demands over the AA3 period. However, in AA3 the load forecast is expected to exceed the power transformer capacity at Canning Vale, Meadow Springs, Mason Road, Rockingham, Welshpool and Clarence Street zone substations.

The 22 kV network also faces challenges of thermally constrained feeders, due to congested feeder exit cables from substations with limited frontages and a few lengthy distribution feeders with voltage constraints. There are plans to resolve these feeder issues by carrying out a number of network solutions such as:

- upgrading of lower rated cables to improve capacity
- installation of new feeders to improve supply capability
- installation of voltage regulators and/or capacitor banks to address the voltage constraints

[13] The capacity of a network increases as the voltage increases. The capacity of an 11 kV network is less than a 22 kV network

- installation of new power transformers at existing substations and/or to establish new substation sites to improve on the overall power transformer capacity

Metro East

There is sufficient overall capacity in the 22 kV network to cater for the forecast electrical demands over the AA3 period. However, in AA3 we expect the load forecast to exceed the power transformer capacity at Midland Junction zone substation. Additionally there are major supply issues due to thermal and voltage constraints of existing distribution feeder assets at Darlington, Kalamunda and Midland Junction zone substations.

Country Planning Region

The Country Planning Region extends as far north as Kalbarri, as far south as Albany and east to Kalgoorlie. This region is divided into four smaller planning regions defined geographically as Country North, Country South, Country East and Country Goldfields.

The Country Planning Region consists of a mixture of rural and urban networks. Overhead distribution networks dominate, with underground networks generally only found in the urban town centres. However, all new residential and commercial subdivisions currently incorporate underground construction.

The overhead rural networks tend to be long feeders with voltage constraints, which sometimes have reliability issues due to exposure to environmental conditions. The underground and overhead networks within the urban areas (of the country region) experience thermal constraints which may impinge on load growth and new developments. Restrictions on feeder exit cable ratings caused by feeder congestion around some substations compound the issue.

There is sufficient overall capacity in the 22 kV network to cater for the forecast electrical demands over the AA3 period. However strong load demand growth due to urban developments in and around Bunbury and Busselton are driving reinforcement requirements in both areas. Moderate load demand growth continues along the coast of the south west area with some minor augmentation required, including additional capacity in the Moora and Albany areas.

Additionally, there is minimal transfer capability between the following pairs of substations due to distance, loading level and strength of the distribution networks in the area:

- Wagerup and Marriott Road
- Capel and Picton
- Capel and Busselton
- Busselton and Margaret River

There is no transfer capability with any of the other substations in the south west area, which include Beenup, Collie, Bridgetown and Manjimup.

Voltage regulation is the major issue for provision of capacity in the south west area. System stability issues, limited capacity transfer capability and equipment malfunction will result if voltage levels are not kept within the ranges specified by the *Technical Rules*. This is due to the distances of the load from the fairly dispersed zone substations located in the area.

Load imbalance issues impact on both power quality and capacity within the south west area. Over the AA3 period significant work is required to rectify overloaded single phase spurs to address these load imbalances, mostly in the Busselton and Margaret River area.

2.2.3.2 Addressing the emerging issues

The discrete projects identified to address the emerging network issues are set out in our transmission and distribution capacity expansion sections 6.1.1 and 7.1.2.

2.3 Asset management approach

We replace assets with a modern equivalent when the assets have reached the end of their useful operational lives (also referred to as their *serviceable* life). This mitigates against the increased likelihood of failure and allows for optimisation of capital and operating expenditure.

Failures in transmission plant are likely to have a significant impact on the supply of power to customers – a major uncontrolled failure is likely to take considerable time to rectify with the potential to affect supply to many thousands of customers. A large number of assets make up the distribution network, where individual asset failure is unlikely to have a large influence on safety and reliability of supply. The way in which we maintain and replace assets is commensurate with the criticality of the assets.

Our investment in asset replacement programs will deliver three fundamental outcomes. These are:

- maximising the safety of the public and Western Power staff when in the vicinity of our assets
- meeting our legislative obligations as described in chapters 7 and 8 of the AAI and for each category of expenditure in this appendix
- ensuring that our assets are capable of maintaining network service levels to ensure that service standard benchmarks are met

Our network management plan (see Appendix L: Network Management Plan) outlines our asset management strategies and how decisions are made to invest in new assets, or to maintain, replace and refurbish assets in accordance with the network investment drivers. Our asset management approach ensures triggers, such as poor asset condition, lead to evaluation of the available options and selection of an appropriate strategy to manage the assets over the remainder of their life.

As assets age, their condition deteriorates and the expected failure rate increases, so eventually it is more economic to replace the asset than to continue maintaining the existing one. The economic factors include the cost of maintenance, the cost of replacement and the cost to customers of reduced network reliability.

Not all assets have the same impact on supply reliability. Accordingly, to manage the network as efficiently as possible, assets have been allocated into the two broad categories of Non-Run to Failure (N-RTF) and Run to Failure (RTF).

2.3.1 Non Run to Failure Assets

Assets as having a significant impact on the reliability, safety, environmental or economic aspects of the business are classed as N-RTF assets. This includes most transmission assets.

These assets undergo routine inspection and maintenance programs designed to keep them in an operating condition for extended periods of time and are proactively replaced prior to failure to ensure the performance levels of the network are maintained.

The end of life and replacement criteria is different for each network asset. An appropriate combination of driving factors such as condition, historical rate of failure for a particular asset group and maintenance factors are considered during asset assessment. In addition to this, probability distribution curves are used to assess the likelihood of failure based on asset age. This analysis, in conjunction with asset age profiles, informs the forecast of future asset replacement requirements.

It is important to note that this is a predictive tool. Actual replacement is undertaken using actual asset condition as the driver. See Appendix L: Network Management Plan for further detail.

2.3.2 Run to Failure Assets

RTF assets have minimal impact on the overall network performance and as such, they undergo minimal maintenance or inspection and operate until they fail.

These assets are allocated a *nominal* or *expected* life which is based on industry standards, historical data and experience of Western Power's asset managers. The nominal life is defined as the duration over which the asset is expected to perform, without a significant increase in failures or maintenance costs. The nominal life is used for medium to long term forecasting of expected replacement volumes of RTF assets.

Some RTF assets are subject to inspection or maintenance programs, but are not replaced until they fail. More general asset inspection programs are also carried out on RTF assets to check for hazards and to ensure public safety.

2.3.3 Programming and scheduling work

We adopt a long term view to assess replacement whilst also prioritising and addressing immediate needs. Network management plans are updated every year as an input to Western Power's annual planning cycle.

Asset replacement works are optimised against other programs of work to ensure we are efficiently minimising costs in capital programs. We have used the overlaps and dependencies model as discussed in section 7.7 of the AAI as one of the primary tools for eliminating duplication across planned transmission and distribution programs of work.

In addition, the smart planning tool outlined in section 7.7 of the AAI ensures we are also looking to minimise the number of planned outages on the transmission network and minimise mobilisation costs across capital and operating expenditure on transmission primary plant.

3 Transmission operating expenditure

Transmission operating expenditure covers work to operate and maintain the transmission assets in the Western Power Network.

In AA3 we will spend $456 million on transmission operating and maintenance activities which are necessary to ensure the continuous provision of covered services for customers. Of this, $17 million relates to non-revenue cap services which are not recovered through reference tariffs.

As set out in chapter 7 of the AAI, our transmission network operating expenditure is segregated into the following high level categories: maintenance, operations and other operating expenditure. The detailed and high level categories of expenditure are shown in Table 6.

Table 6: AA3 forecast transmission network operating expenditure ($ million real at 30 June 2012)

AA3 expenditure by category	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of total
Preventative routine	19.7	20.7	21.8	22.9	24.6	109.7	24.0%
Preventative condition	11.1	11.6	12.3	13.0	14.0	61.8	13.5%
Corrective deferred	11.1	11.6	12.2	12.8	13.7	61.5	13.5%
Corrective emergency	2.5	2.6	2.8	2.9	3.1	14.0	3.1%
Maintenance	**44.5**	**46.5**	**49.0**	**51.6**	**55.3**	**246.9**	**54.1%**
SCADA and communications	12.9	13.5	14.2	14.9	16.0	71.5	15.7%
Network operations	9.5	10.2	10.9	11.6	12.4	54.6	12.0%
Non-revenue cap services	3.1	3.2	3.4	3.6	3.9	17.2	3.8%
Operations	**25.6**	**26.8**	**28.5**	**30.1**	**32.3**	**143.3**	**31.4%**
Non-recurring operating expenditure	13.9	7.2	11.0	14.0	20.1	66.3	14.5%
Other	**13.9**	**7.2**	**11.0**	**14.0**	**20.1**	**66.3**	**14.5%**
Transmission network operating expenditure	84.0	80.6	88.5	95.7	107.7	**456.5**	**100.0%**
Less non-revenue cap services	3.1	3.2	3.4	3.6	3.9	17.2	3.8%
Transmission operating expenditure to be recovered through reference tariffs	80.8	77.4	85.1	92.1	103.8	439.3	96.2%

3.1 Maintenance

In AA3 we will spend $247 million, 54% of forecast transmission network operating expenditure, on maintaining the transmission network.

We deliver our maintenance activities through four distinct programs:

- *preventative routine* – routine asset inspection cycles and equipment tests
- *preventative condition* – responsive works based on asset condition
- *corrective emergency* – responsive works based on a network emergency or failure in service
- *corrective deferred* – follow-up works after emergency network repairs

REGULATORY OBLIGATIONS

We are obliged to maintain our network assets to maintain provision of reliable covered services, to the appropriate level of quality and in a safe manner in accordance with the following key pieces of legislation:

- Electricity Act 1945 and Electricity Regulations under the Act
- Electricity (Supply Standards and System Safety) Regulations 2001 require that we must ensure that, so far as is reasonable and practicable, activities are carried out in such a way as to provide for the safety of persons, including employees of and contractors to Western Power
- Electricity Industry Act 2005
- Technical Rules clause 1.8.2 (c) which requires the management, maintenance and operation of the transmission and distribution systems to minimise the number and impact of interruptions or service level reductions to Users
- Electricity Industry (Network Reliability and Quality of Supply) Code 2005 (clause 10) which requires that we must, so far as is reasonably practicable, reduce the effect of any interruption on a customer

In order to meet these obligations we must undertake transmission maintenance activities, including inspection and asset monitoring, to prevent asset degradation and thereby reduce the frequency and occurrence of network outages.

3.1.1 Preventative routine maintenance

In AA3 we will spend $110 million, 24% of forecast transmission network operating expenditure, on preventative routine maintenance.

Preventative routine maintenance is a schedule of planned maintenance and inspection actions aimed at:

- predicting the onset of asset failure and identifying unsafe conditions through inspections
- detecting failures before they impact on asset function, network reliability and human safety
- maintaining expected asset life by ensuring assets are in good serviceable condition

The activities include monitoring, testing and inspecting equipment that is undertaken either at predetermined intervals or is initiated by equipment operations or asset condition. In addition to inspection and testing, lubrication and routine minor part replacement are carried out as part of preventative routine maintenance.

Conditions identified through preventative routine maintenance inspections inform works to be undertaken as part of:

- preventive condition maintenance
- asset replacement capital investment
- regulatory compliance capital investment

A breakdown of AA3 forecast transmission preventative routine maintenance expenditure by activity is shown in Table 7 and Figure 11.

Table 7: AA3 transmission preventative routine expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Substation primary plant maintenance	5.1	5.3	5.6	5.9	6.3	28.2
Substation HV equipment testing	2.1	2.2	2.3	2.4	2.6	11.5
Secondary equipment maintenance	2.1	2.2	2.3	2.4	2.5	11.4
Substation maintenance buildings and grounds	2.0	2.1	2.2	2.3	2.5	11.2
Substation battery maintenance and inspection	1.8	1.9	2.0	2.2	2.3	10.3
Insulator siliconing	1.4	1.5	1.6	1.7	1.8	8.1
Pole top inspection and line patrols	1.1	1.1	1.2	1.3	1.4	6.0
Pole base inspections and treatment	1.0	1.1	1.1	1.2	1.3	5.8
Other	3.1	3.3	3.4	3.6	3.9	17.2
Total	**19.7**	**20.7**	**21.8**	**22.9**	**24.6**	**109.7**

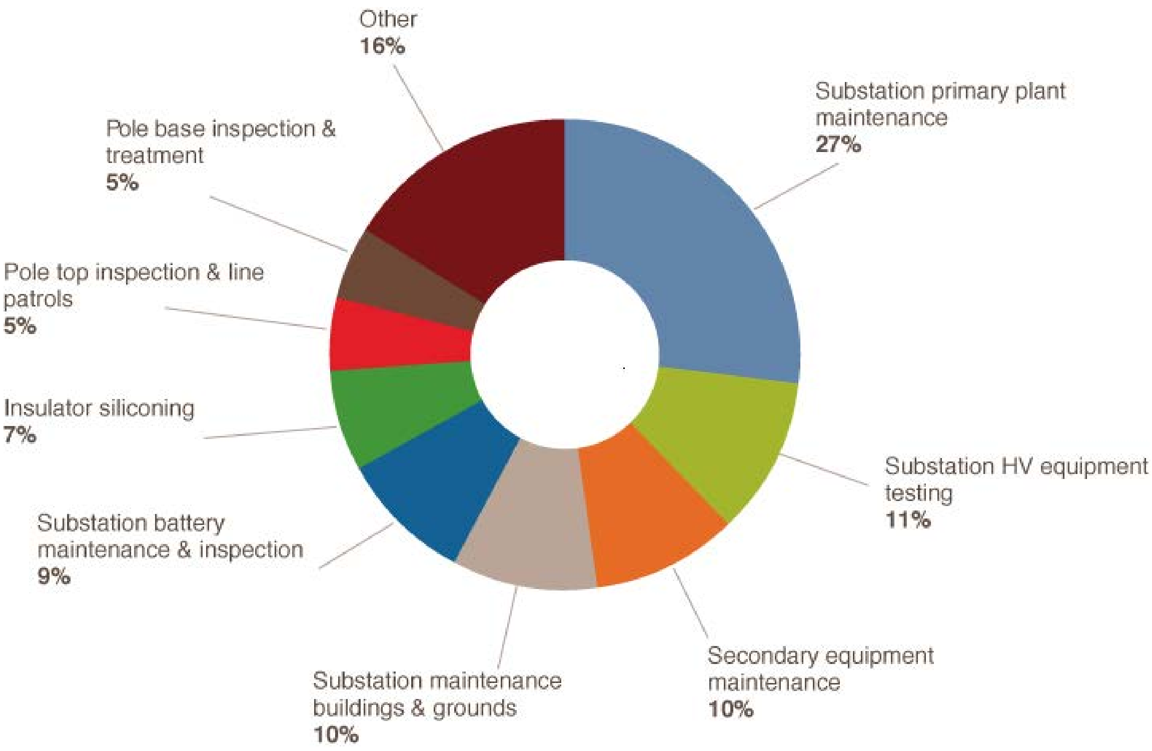

Figure 11: AA3 transmission preventative routine expenditure by activity

Each of these activities is discussed in the following sections.

3.1.1.1 Substation primary plant maintenance

Substation primary plant maintenance represents 27% of forecast transmission preventative routine maintenance expenditure. Substation primary plant maintenance is the routine maintenance of switchgear (circuit breakers), disconnectors, transformers, and other major plant that is used in transmission substations, including zone substations. Western Power carries out this maintenance on a regular basis in accordance with specific procedures for each type of equipment.

If the routine maintenance is not performed, Western Power would not detect a deteriorating asset until it suffers a significant failure. This would result in an increase in the likelihood and potential consequence of equipment failure and could require a more costly repair than would otherwise have been the case. In the worst case, if the failure is catastrophic[14], a replacement unit may be required much earlier than indicated by the nominal asset life or neighbouring equipment may be damaged. This represents a poor utilisation of the original asset and is not considered good electricity industry practice.

If equipment is found to be in a condition that requires further and major (but not emergency) attention during the course of routine maintenance, a plan is established for that item of plant and similar items to be maintained under the preventative condition maintenance activity.

3.1.1.2 Substation HV equipment testing

Substation high voltage equipment testing represents 11% of forecast transmission preventative routine maintenance expenditure. We schedule planned high voltage electrical testing of major substation plant such as indoor switchboards, power transformers and circuit

[14] DM 6242026: Western Power's corporate risk assessment criteria for definition

breakers. The aim of the routine testing is to identify any defects arising from the tests and address any issues before they become major ones. This includes identifying problems associated with particular makes and models of equipment and targeting those for repair or replacement before significant defects and / or faults occur.

Undertaking these activities reduces the risk of failures and contributes to service standards being maintained.

3.1.1.3 Secondary equipment maintenance

Secondary equipment maintenance represents 10% of forecast transmission preventative routine expenditure. Secondary equipment maintenance is planned maintenance performed on protection relays. The protection routine maintenance program has been designed to detect and rectify defective or out of tolerance protection relays.

The consequence of not performing routine maintenance on this equipment is that the risk of malfunctioning equipment increases and this has further consequences on system reliability and service standards.

3.1.1.4 Substation maintenance buildings and grounds

Substation maintenance on buildings and grounds represents 10% of forecast transmission preventative routine maintenance expenditure. We have 128 zone substations and 24 terminal substations to maintain. This activity includes:

- an annual inspection of each substation site, with conditions recorded
- maintenance of substation buildings, fencing, lighting, vegetation and landscaping
- cleaning
- daily security guard patrols
- security system monitoring and maintenance
- six monthly fire extinguisher servicing and fire systems maintenance

The majority of conditions recorded from inspections relate to substation security, with the perimeter fence being a key consideration. Western Power seeks to ensure that members of the public cannot gain access to substation sites with high voltage equipment. A fencing and security upgrade program has been defined as part of the transmission regulatory compliance substation security capital program of work (see section 6.4.1.4 to rectify ongoing issues arising in relation to substandard fencing)

Substation maintenance buildings and grounds routine maintenance help to determine unsatisfactory risk to public safety as well as avoiding compromising service standard performance as a result of incidents involving unauthorised access to substations.

3.1.1.5 Substation battery maintenance and inspection

Substation battery maintenance and inspection represents 9% of forecast transmission preventative routine maintenance expenditure. SCADA and secondary systems are powered by battery banks that are installed as part of a substation. Battery maintenance is essential as failure of the battery system could:

- place major plant at risk of damage
- affect our ability to monitor and control the affected substation from the control centre, including the ability to control and shift the supply point (within the substation) to the loads

This activity includes:

- three monthly battery and charger maintenance and detailed substation inspections
- one, three and five year battery and charger maintenance
- earthing and hot stick maintenance

Substation battery maintenance and inspection prevents interruptions to supply from failure of a substation battery bank.

3.1.1.6 Insulator siliconing

Insulator siliconing represents 7% of forecast transmission preventative routine maintenance expenditure. Pollution particles build up on insulators which will degrade the insulator's ability to carry out its function of insulating between conductive paths. The pollutants combined with moisture eventually form an unwanted conductive path that can lead to line outages caused by flashovers (electric arcing), pole top fires and even bushfires. This activity involves applying Sylgard compound to transmission line insulators to reduce the likelihood of insulator flashover and pole top fires due to leakage current over polluted insulators.

There are some 1,500 assets treated annually. These make up a small proportion of the total asset population however those treated are targeted because they are at high risk due to their location. The targeted locations include new roads/sites (dust), near the sea (salt) and near industrial sites/mines (pollutants).

This activity does not include the application of Sylgard to substation insulators, which is covered by a separate activity.

Insulator siliconing manages the impact of insulator flashover on service standards (network outages) and also on public safety from fire risk.

3.1.1.7 Pole top inspections and line patrols

Pole top inspections and line patrols represent 5% of forecast transmission preventative routine expenditure. We carry out a schedule of pole top inspection and line patrols to identify and report on obvious defects associated with transmission power lines. The defects include structural damage, faulty earthing, accurate asset tag (nameplate) information, defaced nameplates, fauna on structures, evidence of third party damage, clearances and easements, insulators and conductors. Inspections are carried out via both helicopter and ground patrol.

These inspection activities help ensure that service standards to customers are maintained by detecting line asset conditions that could compromise supply reliability, as well as mitigating public safety issues. In addition, pole top inspections and line patrols ensure Western Power's compliance with the recommendations listed under *Energy Safety Order 01-2009*[15] regarding management of poles.

Wood poles are our highest risk pole population in the network. Effective management of wood poles, pole top equipment, conductors and conductor accessories is critical to operating the Western Power Network. We operate a condition based asset management regime monitoring the condition, and therefore serviceability, of the pole and pole top asset population on a four year inspection cycle. To gain efficiencies of scale, we contract for this work across both transmission and distribution poles where it is possible to do so.

[15] Available at: http://www.commerce.wa.gov.au/energysafety/

3.1.1.8 Pole base inspections and treatment

Pole base inspection and treatment represents 5% of forecast transmission preventative routine maintenance expenditure. This activity involves the inspection and chemical fungicide treatment of wooden poles in the transmission network. It includes those poles located within substations and poles on decommissioned transmission lines that are yet to be disassembled. We carry out the inspections and treatment every four years starting 10 years from the date a given pole was installed. The aim is to detect a potential failure before failure of the asset and thereby seek to minimise the transmission pole failure rate. Pole failure can cause significant public safety hazards including:

- electric shock due to live cables being at ground level
- damage to property and people associated with falling pole or lines
- fire (over 25% of wood poles are located in extreme and high fire risk areas)

In addition, pole base inspection and treatment ensures compliance with the recommendations listed under *Energy Safety Order 01-2009* regarding management of poles.

3.1.1.9 Other

The following activities are individually less than $1 million per year or below 4% of forecast transmission preventive routine maintenance expenditure. Nonetheless, these activities make vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Transmission substation inspections (3.9%) – this activity includes monthly inspections for both zone and terminal substations, 3 monthly zone substation maintenance, 6 monthly portable earth and hot-stick inspection maintenance and monthly inspection of static var compensators (SVC) plus many smaller tasks at Western Power’s 128 zone substations and 24 terminal substations. Network reliability and integrity is exposed to risk if these conditions are not identified and subsequent maintenance performed.
- Underground system inspection (3.5%) – annual inspection and testing of transmission cable systems operating at voltages 66 kV and above, to ensure their integrity and ability to perform their intended network function. Includes cable alarm tests, cable patrols, sheath tests, oil pressure tests and oil analysis. This mitigates against the risk of a cable sheath fault (there are two or three such sheath faults every year on average), which can lead to environmental damage and catastrophic cable failure, affecting the security of supply to customers as well as requiring costly replacement work.
- Line insulator washing (2.7%) – washing line insulators in susceptible areas using elevated work platforms or helicopters to remove pollutant build-up that degrades insulator performance and can lead to pole top fires or flashover events. Western Power will treat approximately 8,000 of the highest risk assets at highest risk every year. The insulators requiring treatment are typically those that are candidates for siliconing and the washing program provides an effective short term intervention.
- Substation insulator washing (1.8%) – a proactive program targeting substations that are at risk of having excessive pollutants on their insulators, particularly those located close to industrial areas and the coastline. Insulator washing reduces the risk of flashovers and outages caused by breakdown of the insulation.
- Vegetation inspections (1.5%) – identification of vegetation that encroaches on the clearance zone near overhead line conductors, increasing the risk of the vegetation

coming into contact with the live conductors. We inspect every transmission line each year (approximately 258 transmission lines) and prioritise findings to be completed under the vegetation maintenance preventative routines activity.

- Substation transformer condition monitoring (0.8%) – this activity remotely monitors and assesses the working condition of zone substation transformers. This enables Western Power to act upon any conditions that indicate possible failure without jeopardising customer supply or safety of persons within the vicinity. The monitoring targets components on the transformer that have historically proven susceptible to failure such as bushings and tap changers.
- Thermo-graphic surveys (0.6%) – these surveys provide early identification of hot spots on energised power lines and electrical equipment within zone substations. Such faults cause significant damage as the fault generally results in a flashover from the hot joint to other adjacent phase conductors or the earth conductor. In addition the occurrence of a fault when the transmission line is at or near peak load presents a significant operational challenge to the restoration of supply without overloading adjacent lines.
- Earthing inspections (0.4%) – visual inspection and measurement of ground resistance and soil resistivity. This mitigates public safety risk (through electric shocks and electrocution) from high earth potential rise that may occur during short circuit faults and includes inspection of all earthed structures outside of transmission substations. Issues generally arise from loose or unbolted earthed connections, vandalism, vehicle damage, and corroded leads/crimps.
- Insulating oil testing (0.4%) – annual testing of the insulating oil in power transformers to determine transformer condition. Dissolved gas analysis can indicate electrical discharges, partial discharges, oil overheating and paper overheating before permanent damage is done to the transformer. Measurements of water in the oil and the oils dielectric strength are also determined. Early detection of issues can prevent more permanent and serious damage to expensive transformers.
- Substation sylgarding (0.2%) – application of Sylgard compound to insulators within substations reduces electrical discharge and flashover events caused by surface pollutants that impact on reliability and public safety risk (from fire). We apply sylgard on two substations a year, prioritised based on risk or location.

3.1.2 Preventative condition maintenance

In AA3 we will spend $62 million, 14% of forecast transmission network operating expenditure, on preventative condition maintenance.

Preventive condition maintenance is a schedule of planned maintenance actions performed as a result of conditions or defects primarily identified during the preventive routine maintenance programs. Preventive condition maintenance minimises safety risks, reduces system downtime and maintains reliability. The ideal preventive maintenance program would prevent all critical asset failures before they occur.

Preventative condition maintenance will help us to efficiently minimise costs by:

- increasing the effective service life of maintained assets and therefore long term capital replacement costs
- performing maintenance under a scheduled work scenario rather than more costly emergency repair

A breakdown of AA3 forecast transmission preventative condition maintenance expenditure by activity is shown in Table 8 and Figure 12.

Table 8: AA3 transmission preventative condition maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Line easement vegetation maintenance	4.4	4.6	4.9	5.2	5.6	24.6
Overhead lines maintenance	3.7	3.9	4.1	4.3	4.7	20.7
Plant and building refurbishment	1.5	1.5	1.6	1.7	1.8	8.1
Substation primary plant maintenance	0.7	0.7	0.7	0.8	0.8	3.8
Underground cable maintenance	0.5	0.5	0.5	0.5	0.6	2.6
Other	0.4	0.4	0.4	0.4	0.5	2.1
Total	**11.1**	**11.6**	**12.3**	**13.0**	**14.0**	**61.8**

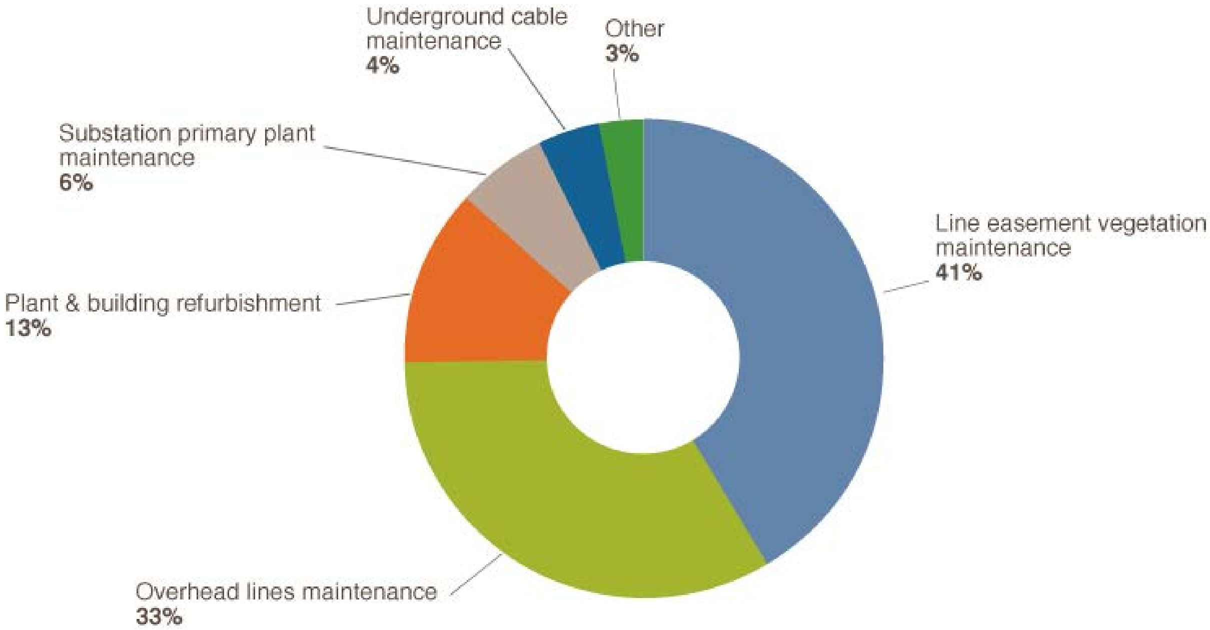

Figure 12: AA3 transmission preventative condition expenditure by activity

Each of these activities is discussed in the following sections.

The segregation of operating and maintenance tasks into categories is important in our planning to optimise what can be somewhat random tasks at the mercy of external forces (for example, accidents, faults and extreme weather). In an electrical power transmission environment, these circumstances can bring extreme safety, fire, property damage, supply reliability and other discrete risks. Thus, the previous sections have explained our transmission preventative maintenance activities – these are the more predictable tasks. Section 3.1.3 and 3.1.4 explain the activities which make up Western Power's responsive works to address network emergencies and in-service failures.

3.1.2.1 Line easement vegetation maintenance

Line easement vegetation maintenance represents 40% of forecast transmission preventative condition maintenance expenditure. Vegetation (primarily trees) can grow into transmission lines or make contact with lines under high winds. The line easement vegetation maintenance program reduces the risk of this by cutting vegetation in the vicinity of the lines. Vegetation is cut to a level that ensures that no vegetation will be in the safety clearance zone until the start of the next inspection cycle. This program runs all year for every transmission line, but has the specific objective of finishing all extreme and high fire risk zones before 15 November each year, the beginning of the bushfire season. Historically, we clear approximately 13% of the transmission lines inspected as part of preventative routine maintenance vegetation inspections, or 4,350 spans per annum.

This activity helps maintain safety and reliability of the network by reducing the risk of network outages and/or bushfires caused by vegetation coming into contact with transmission lines. Additionally, the *Code of Practice for Personnel Electrical Safety for Vegetation Control Work near live Power Lines*[16] details the requirements of vegetation management as per the *Electricity Act 1945*[17] and the *Electricity Regulations 1947*[18].

3.1.2.2 Overhead lines maintenance

Overhead line maintenance represents 33% of forecast transmission preventative condition maintenance expenditure. This activity involves the repair of defects on transmission power lines and associated equipment identified during inspections or other routine maintenance tasks. It covers:

- poles and structures including arranging for replacement if this is required
- ground anchors, guy wires and all associated equipment
- high voltage line apparatus and all associated equipment
- high voltage overhead conductors which include the stringing, tensioning, tying in and jointing of all associated equipment
- testing and maintenance of earthing of the overhead network

This activity maintains the integrity of the overhead line assets and hence the transmission network of which they are a key part. Failure to perform this work can increase the risk of line assets failing in several ways including low conductors, conductors on the ground, even pole or tower failure in more extreme cases. Any of these scenarios would result in network outages and risk to public safety. The public safety risk in a populated area would be very high in the more extreme cases of pole or tower failure.

3.1.2.3 Plant and building refurbishment

Plant and buildings modifications/refurbishment represents 13% of forecast transmission preventative condition maintenance expenditure. This activity includes work to bring plant or buildings at zone substations and terminal substations up to an acceptable condition

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[16] Available at: http://www.commerce.wa.gov.au/energysafety/PDF/Publications/Code_of_Practice_for.pdf

[17] Available at: http://www.slp.wa.gov.au/statutes/swans.nsf/5d62daee56e9e4b348256ebd0012c422/875a8a6e4d49f1154825665000058020/$FILE/Electricity%20Act%201945.PDF

[18] Available at: http://www.slp.wa.gov.au/statutes/regs.nsf/3b7e5f26432801b348256ec3002c128c/e5d3b77f97701ec3482568f000167a74/$FILE/Electricity%20Regulations%201947.PDF

particularly in relation to the site's security aspects such as lighting and fencing. This work is initiated as a result of defects identified through the routine inspection program.

The majority of conditions recorded from inspections relate to substation security, as outlined in section 3.1.1.4. These activities help to mitigate unsatisfactory risk to public safety as well as avoiding compromising service standard performance by unauthorised access to substations.

3.1.2.4 Substation primary plant maintenance

Substation primary plant maintenance represents 6% of forecast transmission preventative condition maintenance expenditure. This activity involves maintenance of primary plant within zone substations and terminal substations. This involves repair of defects identified from inspections or other preventative routine maintenance tasks as outlined in section 3.1.1.1. Failure to do this work will result in a deterioration of the primary plant which will eventually lead to equipment failure. This is undesirable because the time and cost to reinstate the plant will be higher than it would have otherwise been under a preventative maintenance approach.

3.1.2.5 Underground cable maintenance

Underground cable maintenance represents 4% of forecast transmission preventative condition maintenance expenditure. This activity comprises the repair of any defects on transmission cables (66 kV or above) following the annual inspection and testing process. This mitigates against the risk of a cable sheath fault (there are two or three such sheath faults every year on average), which can lead to catastrophic cable failure, affecting the security of supply to customers as well as requiring costly replacement work.

3.1.2.6 Other

The following activities are individually less than $0.2 million per year or 1.2% of forecast preventative condition maintenance expenditure. Nonetheless, these activities make vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Investigative/triggered maintenance (1.2%) – maintenance work based on trigger points recommended by the manufacturer to mitigate against warranty violation. An additional driver is equipment failure which could be explosive and risk injury to employees and the public as well as loss of plant and assets.
- Condition monitoring (0.8%) – installation of equipment to monitor critical assets during their normal operation and to provide data or information for making condition assessments. By proactively monitoring the assets, Western Power is able to detect a path to deterioration before a major failure occurs thus providing a more cost effective approach.
- Protection modifications and refurbishment (0.5%) – on site refurbishment or modification (including minor design changes) of protection systems to rectify deficiencies and ensure proper operation. The main driver for this activity is asset condition. This activity ensures that public safety risks are minimised and that Western Power can respond to issues in the protection system that will affect network integrity, so that service standards are maintained.
- Plant test failure replacement (0.5%) – replacement of an item or specification of plant where testing has indicated an unacceptable condition. There is often limited scope to align this with other planned work as the failure items arise on an ad hoc

basis and often must be replaced with minimal delay to ensure employee and public safety, and network integrity.

- Transformer refurbishment (0.2%) – since 2000, we have experienced 9 failures of substation transformers built in the 1970's of the same specification. These failures were caused by insufficient mechanical strength of the transformer windings leading to an inability to withstand the forces of short circuit faults. The transformer refurbishment activity addresses these issues through inspection of transformers susceptible to winding shrinkage and failure, reclamping where required and refurbishment of burnt gaskets and coolers.
- Earth connection maintenance (0.1%) – repair, remediation or replacement of earths associated with pole mounted equipment (down earths) and substations (earth pits and grading rings) that have been identified from inspections or other preventative routine maintenance tasks. Substation earth connections can result in power quality issues, incorrect operation of upstream protective devices and voltage rise of earthed metalwork within customer premises. It is also important to adequately earth ground-mounted and pole mounted switchgear to ensure the safety of Western Power operators during local switching operations.

3.1.3 Corrective deferred maintenance

In AA3 we will spend $61 million, 13% of forecast transmission network operating expenditure, on corrective deferred maintenance.

Following an emergency maintenance situation, works that are not urgent are rescheduled for attention using standard workforce practices as part of corrective deferred maintenance. This is based on our practice of efficiently minimising costs by reducing, where possible, works conducted in more costly emergency situations in favour of completing those same works at lower cost in a more controlled and planned situation. The deferred activity is usually completed within the same financial year as the corresponding emergency event or events.

Activities consist of asset repairs, environmental cleanups and emergency follow ups. If we do not carry out corrective deferred maintenance of its assets, service standards will be adversely affected eventually impacting on the supply to customers. This is because the purpose of corrective deferred maintenance is to make more complete repairs to equipment or network that was attended to and made safe during an emergency situation so that it no longer represents an emergency situation. If the more permanent repairs are not made, there will be a higher risk of future failures.

Additional compliance issues that affect specific activities within corrective deferred maintenance include Western Power's environmental obligations under the *Environmental Protection Act 1986*[19] and the *Contaminated Sites Act 2003*[20]. This activity is also supported by Western Power's Environmental Policy[21]

A breakdown of AA3 forecast transmission corrective deferred maintenance expenditure by activity is shown in Table 9 and Figure 13.

[19] Available at: http://www.epa.wa.gov.au/Pages/default.aspx
[20] Available at: http://www.dec.wa.gov.au/content/view/2868/1579/
[21] DM4004094: *Western Power's Environmental Policy*

Table 9: AA3 transmission corrective deferred maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Substation primary plant maintenance	5.9	6.1	6.4	6.7	7.2	32.3
Substation site maintenance	1.3	1.4	1.4	1.5	1.6	7.3
Environmental cleanup	1.3	1.4	1.4	1.5	1.7	7.3
Protection equipment maintenance	0.9	1.0	1.0	1.1	1.1	5.1
DC systems maintenance	0.6	0.6	0.6	0.6	0.7	3.0
Other	1.2	1.2	1.3	1.4	1.4	6.5
Corrective deferred total	**11.1**	**11.6**	**12.2**	**12.8**	**13.7**	**61.5**

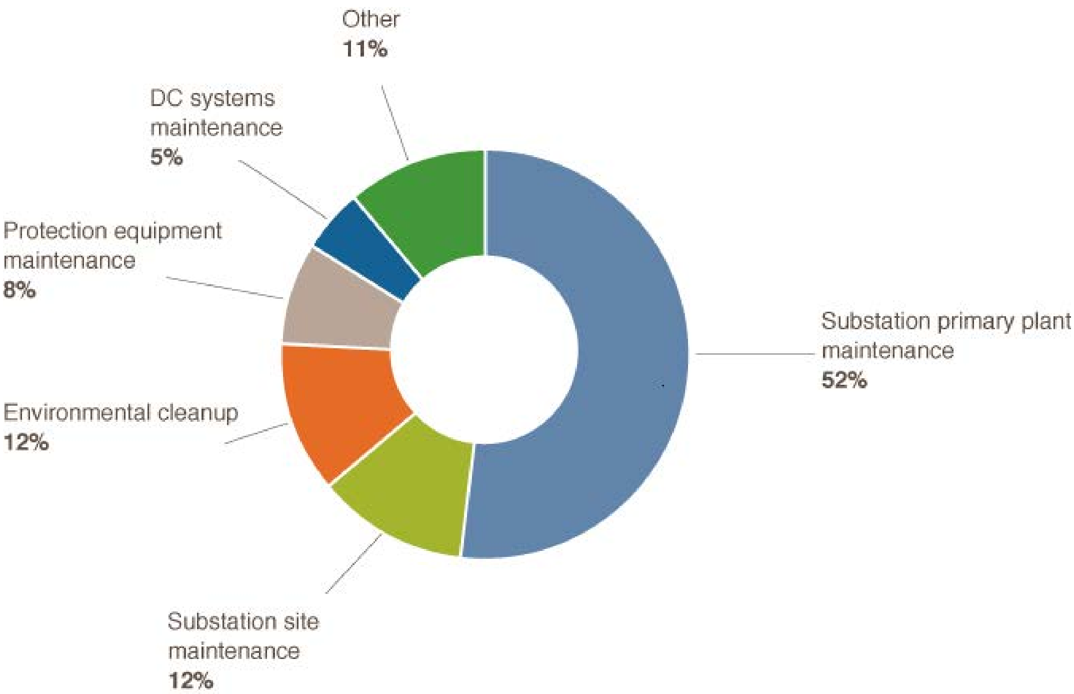

Figure 13: AA3 transmission corrective deferred expenditure by activity

Each of these activities is discussed in the following sections.

3.1.3.1 Substation primary plant maintenance

Substation primary plant maintenance represents 52% of forecast transmission corrective deferred maintenance expenditure. This activity provides for longer term repair of substation primary plant that was affected or damaged during an emergency situation. Such plant can include power transformers, circuit breakers and isolator switches. As with other deferred activities, this is follow-up work to complete the temporary repairs or solutions carried out under corrective emergency maintenance.

3.1.3.2 Substation site maintenance

Substation sites maintenance represents 12% of forecast transmission corrective deferred expenditure in AA3. Infrastructure in this category includes substation buildings, roads, fences and alarm systems. This activity provides longer term repairs and solutions to infrastructure affected or damaged during an emergency situation. It is follow-up work to complete the temporary measures carried out under corrective emergency maintenance.

Some of these items require more urgent attention than others. For example, a damaged boundary fence will be classed as urgent given the safety risks that arise.

3.1.3.3 Environmental cleanup

Environmental cleanup expenditure represents 12% of forecast transmission corrective deferred maintenance expenditure in AA3. This activity can result from any incident that affects the environment and Western Power's environmental obligations. It includes incidents involving controlled waste, oil spills usually in substations, the correct disposal of polychlorinated biphenyls (PCBs) and the management and remediation of contaminated sites.

This is follow-up work to complete temporary solutions carried out under corrective emergency maintenance.

3.1.3.4 Protection equipment maintenance

Protection equipment expenditure represents 8% of forecast transmission corrective deferred expenditure in AA3. These systems provide protection against short circuit faults that would otherwise damage high capital cost plant and equipment in substations and on transmission lines. Without adequately functioning protection systems, the major plant and equipment will be placed at an increased risk of damage.

Protection equipment expenditure provides longer term repairs and solutions to protection equipment affected or damaged during an emergency situation. It is follow-up work to complete the temporary measures carried out under corrective emergency maintenance.

3.1.3.5 DC systems maintenance

Direct current (DC) systems maintenance represents 5% of forecast transmission corrective deferred maintenance expenditure in AA3. DC systems include the batteries (and battery chargers) that provide the power supply to the protection and SCADA systems. Without the DC systems, the protection and SCADA will not work as required and this will place major plant and equipment at an increased risk of damage.

This activity provides longer term repairs and solutions to DC systems affected or damaged during emergency situations.

3.1.3.6 Other

The following activities are individually less than $0.6 million per year or 4% of AA3 forecast corrective deferred expenditure. Nonetheless, these activities make vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Emergency follow-up underground cables (3.8%) – permanent repair of underground cables that have been repaired temporarily following corrective emergency activities. This ensures the safety and reliability of the network by providing an appropriate long term solution to repair work carried out in an emergency situation.

- Emergency follow-up overhead lines (3.0%) – permanent repair of overhead lines that have been repaired temporarily following corrective emergency activities. This ensures the safety and reliability of the network by providing an appropriate long term solution to repair work carried out in an emergency situation.
- Investigative/triggered maintenance (2.7%) – this is primarily maintenance of the fault recorder network that provide essential data necessary to analyse safety incidents, asset failures, incorrect protection operations and major system disturbances. The outcome is to ensure safety and reliability of the network by addressing poorly performing assets identified by regular incident analysis.
- Vandalism (0.4%) – repairs to assets that are damaged by acts of vandalism, typically substation security fences. The main outcome of this activity is to repair the damage to prevent public access to substation sites and potential safety and reliability risks that follow.
- Motor vehicle impact on poles (0.4%) – this involves the repair of Western Power assets that are damaged as a result of a motor vehicle collision. Vehicle collisions with poles will often involve poles and transmission lines across roads and footpaths. The network needs to be repaired and debris cleared away to ensure public safety and network security.
- Asset damage by unknown perpetrator (0.3%) – repair of assets that are damaged as a result of accidents or deliberate vandalism. There is often little scope for coordination with other work and the cost is not able to be recovered, mainly because the perpetrator cannot be identified. The main outcome of this activity is to repair the damage giving higher priority to issues that affect public safety or supply continuity.
- Television interference repair[22] (0.1%) – this addresses customer complaints due to television interference (TVI) faults caused by the transmission network. This is one of a list of activities that contributes to our 'number of customer complaints per 100,000 customers' performance indicator.

3.1.4 Corrective emergency maintenance

In AA3 we will spend $14 million, 3% of forecast transmission network operating expenditure, on corrective emergency maintenance.

Transmission corrective emergency activities deal with emergency situations as they arise. The need for this type of work usually occurs without warning and the work is performed immediately to ensure restoration of electricity supply to customers as quickly as possible, minimise the safety risk to both the public and Western Power employees and to prevent further damage to equipment. Corrective emergency maintains network performance in an efficient manner by deferring works that are not urgent to be carried out as part of standard working schedules rather than by more costly emergency response units.

Transmission corrective emergency maintenance activities performed cover asset repair, environmental cleanups and emergency follow-ups and contribute to Western Power's corrective maintenance strategy in ensuring maintaining system reliability / security, plant condition and public safety are not eroded.

[22] Under section 2.3.6 of the *Technical Rules*, Western Power '*must respond to all complaints regarding electromagnetic interference in a timely manner and undertake any necessary tests to determine whether or not the interference is caused by equipment forming part of the transmission and distribution systems... If the complaint is justified, the Network Service Provider must, as soon as reasonably practicable, take any necessary action to reduce the interference to below the maximum prescribed levels.*'

A breakdown of AA3 forecast transmission corrective emergency maintenance expenditure by activity is shown in Table 10 and Figure 14.

Table 10: AA3 transmission corrective emergency maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Substation primary plant maintenance	1.7	1.8	1.9	2.0	2.1	9.6
Overhead line maintenance	0.5	0.5	0.5	0.5	0.6	2.6
Secondary equipment maintenance	0.3	0.3	0.3	0.4	0.4	1.8
Corrective emergency total	**2.5**	**2.6**	**2.8**	**2.9**	**3.1**	**14.0**

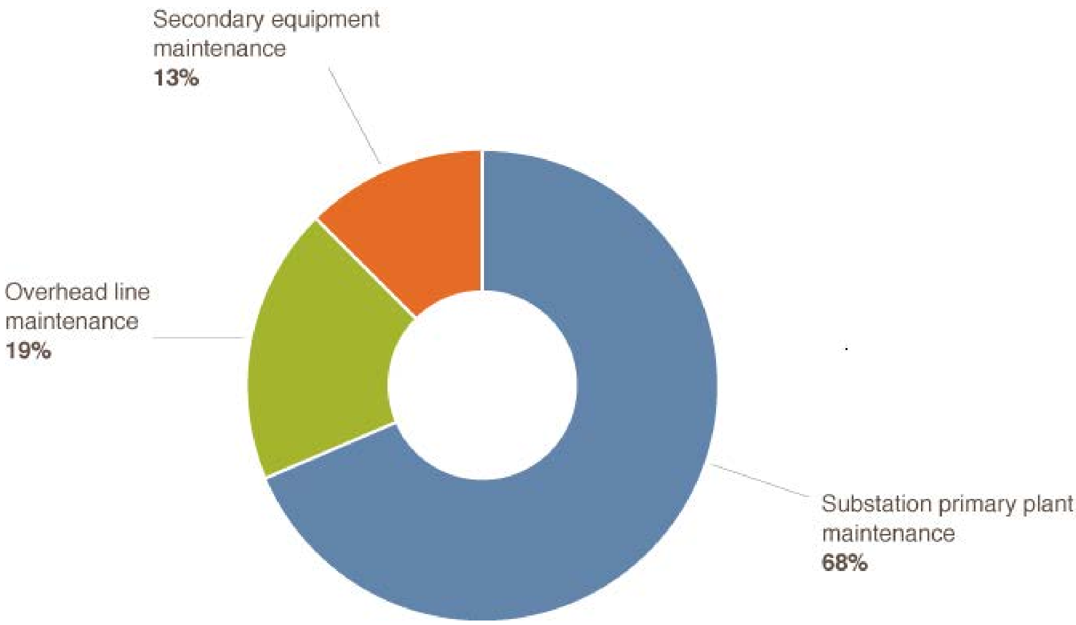

Figure 14: AA3 transmission corrective emergency expenditure by activity

Each of these activities is discussed in the following sections.

3.1.4.1 Substation primary plant maintenance

Substation primary plant emergency maintenance represents 68% of forecast transmission corrective emergency maintenance expenditure. This activity involves the repair or temporary restoration of substation primary plant in emergency situations. This involves making the situation safe to reduce the risk of any serious network performance or public safety consequences.

3.1.4.2 Overhead line maintenance

Overhead lines emergency maintenance represents 19% of forecast transmission corrective emergency maintenance expenditure. This activity is the repair of overhead transmission lines following an emergency situation. This requires management of helicopter emergency patrols of transmission lines as required (for example, emergency response during storms) and this incurs a standby fee and a minimum of two Western Power employees who can observe the power line and associated network assets from either side of the helicopter during the patrol.

3.1.4.3 Secondary equipment maintenance

Secondary equipment emergency maintenance represents 13% of forecast transmission corrective emergency maintenance expenditure. This activity is associated with emergency call-outs to address the breakdown of secondary equipment (such as protection systems, SCADA and communications). If the problem is not fully repaired immediately, contingency arrangements are put in place and permanent repairs are planned and carried out under deferred maintenance.

3.2 Transmission operations

In AA3 we will spend $143 million, 31% of forecast transmission network operating expenditure, to operate the transmission network. Of this, $17 million will be contributed by customers receiving non-revenue cap services.

We operate the transmission network through three distinct activities:

- SCADA and communications systems – carries all information and commands between network equipment and the control centre
- network operations – monitors and controls operation of the transmission network from the control centre
- non-revenue cap services – customer driven requests that are not directly attributable to the provision of reference services and hence are paid for by the requesting customer

3.2.1 SCADA and communications

In AA3 we will spend $71 million, 16% of forecast transmission network operating expenditure, on transmission supervisory control and data acquisition (SCADA) and communications operating expenditure.

Our ability to protect, monitor, control and operate the transmission network is dependent upon us having intelligent communications and control infrastructure with constant visibility of what is happening in the network. Transmission SCADA and communications links to our assets are essential to operate the power system safely and reliably. Continuous operation of the SCADA system means:

- assets are not at risk from small overloads[23]
- emergency switching can be undertaken, for example, requests from the Fire and Emergency Services Authority (FESA) to turn off lines due to bushfires or third party interruptions to network infrastructure can be accommodated
- we can rely on automatic switching for restoration following a fault event
- site safety and security[24] are maintained at acceptable levels only requiring switching to be done locally under situations where the control centre personnel have reduced visibility of what is occurring on site
- generators can be dispatched for load management and line run back schemes

[23] Small overloads are where the equipment is operating above its plant rating but below the operating levels for the protection relays or systems to activate.
[24] As no fire alarm or door alarm visibility would be available

- the transmission system can be modelled in real time for system contingency analysis

This expenditure includes the personnel to operate and maintain critical SCADA and communications systems to ensure that protection communications services do not impact on transmission service level and availability targets. In addition, this activity provides the operational fault and maintenance response capability to ensure that communications links underpinning protection and SCADA systems are available.

REGULATORY OBLIGATIONS

SCADA and communications expenditure focuses on meeting obligations for continuous network control and monitoring to:

1. meet power system performance standards (*Technical Rules* sections 2.2, 2.3.9, 3.2.1, 3.3 and 5.3.1)
2. discharge our responsibility to provide operational co-ordination of the power system and *Wholesale Electricity Market Rules** sections 3.2.8, 6.13.1 and 7.13. In addition, section 2.2 of the *Wholesale Electricity Market Rules* specifies system management requirements which, among other things, involve operating the Western Power Network in safe and reliable manner and requirements to provide data as specified in sections 2.15.6(b), 3.2.8, 6.1.3.1 and 7.13 of the *Wholesale Electricity Market Rules*.
3. meet requirements for transmission system protection (*Technical Rules* sections 2.9.1, 2.9.2 and 2.9.3)
4. meet requirements under the *Technical Rules* including:

   section 2.3.7.1 Short Term Stability (a), (b) and (c).

   section 2.5.2.4 Circuit Breaker Failure

   section 3.2.5 (b) Protection

   section 3.3 (various) Requirements for connection of generating units

   section 3.4 (various) Requirements for connection of loads

   section 3.6.10 Protection

   section 3.7.3 Relevant Standards (as relate to clause (3)) AS 4777.3 – 2005 Part 3 Grid protection requirements.

   section 4.1 Inspection and testing

   section 4.2 (various) Commissioning of user's equipment

   section 5.5 (various) Protection of power system equipment

   section 5.7 (various) Power system security operation and coordination
5. manage communications facilities to comply with the *Telecommunications Act 2004** and to manage and meet the related obligations
6. collect asset performance and condition data to fulfil our asset management obligations under Section 14 of the *Electricity Industry Act 2004** (see full details in section 5.2.1)

*Available at: http://www.austlii.edu.au/au/legis/wa/consol_act/eia2004261/

* Available at: http://www.austlii.edu.au/au/legis/wa/consol_reg/eiemr2004641/

* Available at: http://www.austlii.edu.au/au/legis/wa/consol_act/taawaa1996600/notes.html

A breakdown of AA3 forecast transmission SCADA and communications operating expenditure by activity is shown in Table 11 and Figure 15.

Table 11: AA3 transmission SCADA and communications expenditure by activity

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Operations	7.1	7.5	7.9	8.3	8.9	39.6
Corrective maintenance	4.0	4.2	4.4	4.6	4.9	22.0
Planning	1.3	1.4	1.4	1.5	1.6	7.2
Routine maintenance	0.5	0.5	0.5	0.5	0.6	2.7
Total	**12.9**	**13.5**	**14.2**	**14.9**	**16.0**	**71.5**

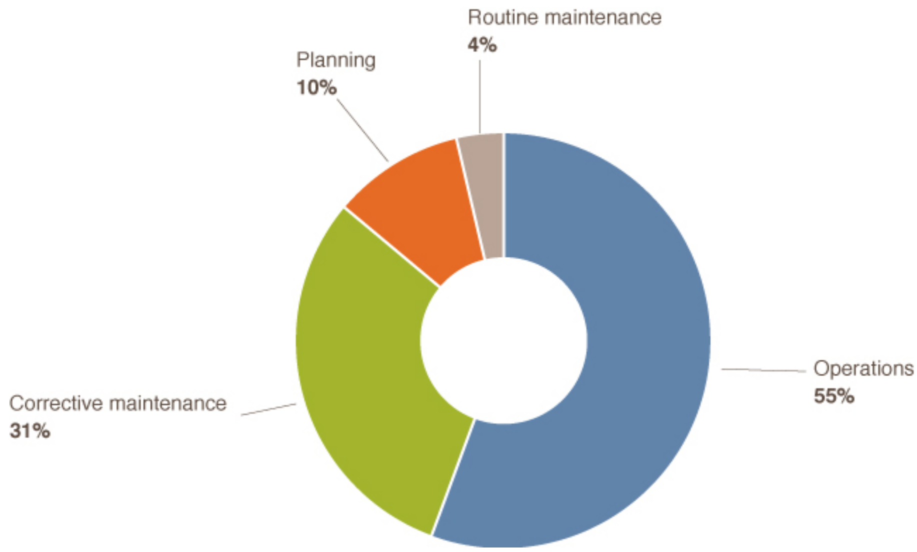

Figure 15: AA3 transmission SCADA and communications expenditure by activity

Each of these activities is discussed in the following sections.

3.2.1.1 Operations

SCADA and communications operations represent 55% of forecast transmission network operating expenditure. Under this activity we:

- maintain the operations centres for the communications system at Mount Claremont
- maintain the SCADA XA-21 master station equipment at the East Perth Control Centre
- incur costs to cover our requirement to manage Australian Communications and Media Authority (ACMA) licensing for radio systems, operating system licensing, communications site leasing and power

The activity maintains the current level of availability of communications and SCADA systems. This enables:

- system management to efficiently manage the transmission system
- us to monitor the network performance and measure and retain system performance parameters prescribed by the *Technical Rules*
- us to provide data to market participants as specified in the *Wholesale Electricity Market (WEM) Rules*

STEP INCREASES IN AA3

We require step increases in expenditure during AA3 to accommodate:

- additional maintenance and operational activities from 2011/12 of $0.8 million required to meet the substantial increase in SCADA and communications assets as a proportion of the capital base (this is in addition to general network growth)
- an additional $1 million from 2012/13 for the new Clarity/Oracle licences following completion of the Clarity system capital project in 2009/10 and for anticipated cost increases for the new 5 year support contract for Sun systems equipment at Mt Claremont (Clarity support and maintenance provider). It also includes the configuration of the notice of intended outages system, commencement of the Kalgoorlie Microwave project and growth in the power system requiring additional resources to manage and maintain the supporting SCADA and communications equipment

3.2.1.2 Corrective maintenance

SCADA and communications corrective maintenance represents 31% of forecast transmission network operating expenditure in AA3. Corrective maintenance activities are necessary to restore communications and SCADA assets back to their original operational status following faults. The expenditure is necessary to maintain the current level of availability of communications and SCADA systems.

3.2.1.3 Planning

SCADA and communications planning represents 10% of forecast transmission network operating expenditure. Under this activity we develop and maintain strategic asset management plans, technical maintenance documents, a state of the network document and asset missions for existing and new SCADA and communications assets. In addition, we investigate opportunities to optimise the communications network for existing operational needs (protection, SCADA, data networks and voice communications) and for future enhancements. This activity enables transmission capital works from the capacity expansion, customer driven, reliability driven, asset replacement and regulatory compliance categories of expenditure.

SCADA and communications planning enables Western Power to plan and budget for whole of life asset management cycle of the SCADA and communications assets to seamlessly maintain the current level of availability of communications and SCADA.

3.2.1.4 Routine maintenance

SCADA and communications routine maintenance represents 4% of forecast transmission network operating expenditure. Planned routine maintenance activities seek to maintain the communications and SCADA assets at the required level of availability on a proactive basis.

3.2.2 Network operations

In AA3 we will spend $55 million, 12% of total AA3 transmission network operating expenditure, on network operations.

Our transmission network operations centrally monitor and control how the transmission network operates and make decisions about allowing network access for the purposes of maintenance, construction and commissioning of assets.

System operations (part of Western Power’s system management division) maintain the security of the power system so that it can supply the forecast daily load (peak demand and energy) in the most economical manner and within the required technical parameters. A power system as large as the Western Power Network cannot operate without a central control function that coordinates its operation.

This central control function monitors the key parameters of the power system and takes action if any of these indicate a threat to system security. Some of the key parameters include:

- transmission network voltage profiles
- planned transmission network outages
- plant ratings and load flow on plant

The outcomes of this function are to:

- ensure the power system is operated securely within defined guidelines and the quality of supply is in accordance with the *Technical Rules*

- respond to emergency events to prevent or limit customer outages and other impacts
- ensure that system operations also operates in accordance with the *WEM Rules*

The above is done in conjunction with the real time generation market operations undertaken by the separately funded *WEM Rules* ring fenced part of System Management.

Transmission network operations have a critical role in ensuring the efficient and continuous operation of the Western Power Network by:

- making the most of planned outages by doing as much work as is practical using the smart planning practices
- preserving the life cycle of assets by operating equipment within defined limits
- prioritising repairs of assets to limit risks to system security and reliability

REGULATORY OBLIGATIONS

Transmission network operations obligations under the *Technical Rules* include:

- section 2.2 - Power system performance standards
- section 2.3 - Obligations of Network Service Provider in relation to power system performance
- section 4.3 - Disconnection and reconnection
- section 5.3 - Power system operation coordination responsibilities and obligations
- section 5.4 - Control of transmission voltages
- section 5.7 - Power system security operation and coordination
- section 5.10 - Power system operation support

Transmission network operations are a key contributor to us achieving the transmission service standard benchmarks.

A further key obligation affecting transmission network operations is the need to ensure recommendations from audits into our licence and asset management systems are implemented, for example, regularly testing the backup emergency control room at head office to ensure it is in operating condition.

A breakdown of AA3 forecast transmission network operations expenditure by activity is shown in Table 12 and Figure 16.

Table 12: AA3 transmission network operations expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
System operations control centre	6.7	7.1	7.7	8.2	8.7	38.4
Planning and market operations	1.4	1.5	1.6	1.7	1.9	8.2
Control centre administration and management	0.8	0.9	0.9	1.0	1.1	4.7
SCADA operations	0.6	0.6	0.7	0.7	0.8	3.4
Network operations total	**9.5**	**10.2**	**10.9**	**11.6**	**12.4**	**54.6**

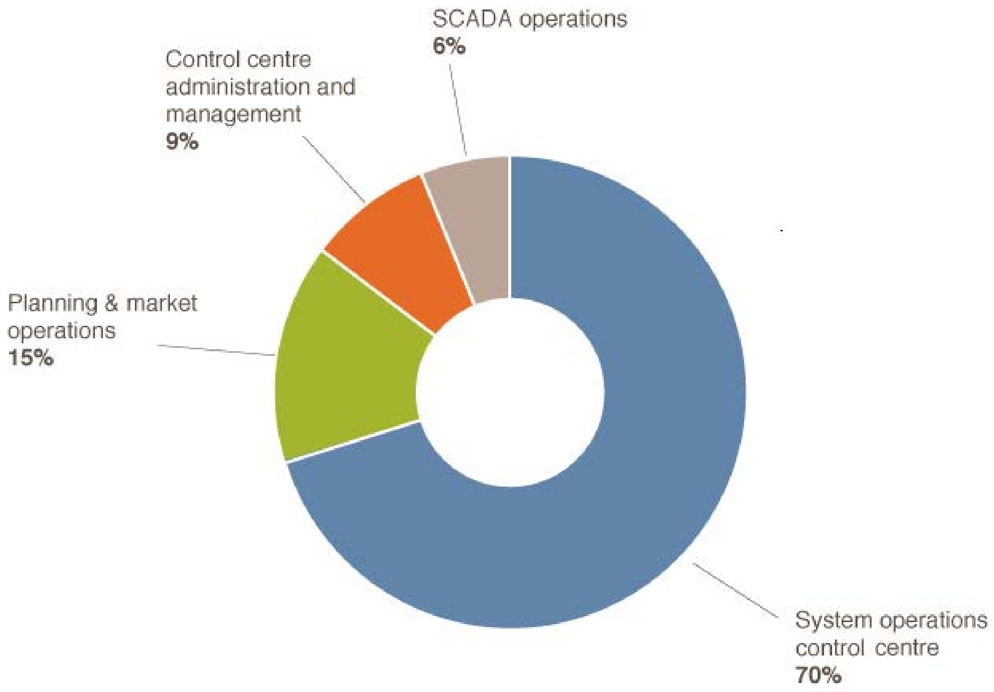

Figure 16: AA3 transmission network operations expenditure by activity

Each of these activities is discussed in the following sections.

3.2.2.1 System operations control centre

System operations control centre (SOCC) represents 70% of forecast transmission network operations expenditure in AA3. SOCC is responsible for the safe, secure and reliable 24 hour 7 days a week operation of the transmission elements of the Western Power Network. Electricity cannot be efficiently stored, thus the SOCC is required to continuously monitor the transmission system and ensure adequate generation is on the system to supply continuously fluctuating loads on the Western Power Network and respond to plant failures and other emergencies. Without the SOCC the electricity system could not operate.

The expenditure covers the personnel, systems and upkeep of procedures for the range of activities the SOCC provides relating to transmission operations. Generation market control and dispatch are excluded as this is part of the ring fenced system management operations. The activities undertaken by the SOCC are:

- load forecasting
- real time control and operation of the transmission network (dispatch, voltage/load control)
- outage coordination – switching operations on the transmission network (for unplanned or fault events, or for planned scenarios such as construction and commissioning phases of projects) through writing switching programs, undertaking onsite and remote switching and combining tasks into one outage event
- system security management involving security margins and disturbance recovery

The key outcome of this activity is maintaining security of the power system by:

- making sure that the transmission network is operated so that the forecast load for the hour/day can be supplied while keeping critical system parameters (such as voltage, current and frequency) within an acceptable range

- responding to unplanned events that threaten security by taking measures to contain and restrict the impact of the event and facilitate the recovery of the system to its normal operating state

3.2.2.2 Planning and market operations

The planning and market operations activity represents 15% of forecast transmission network operations expenditure. While the SOCC deals with the day to day operations of the power system, the planning and market operations activity deals with medium term planning horizons. These are in the range of days, weeks and up to 3 years. It also involves ensuring that market participants are compliant with the *WEM Rules* and that the (ring-fenced) system management operates in accordance with the Market Rules.

Planning and market operations are responsible for:

- the security and reliability of the power system within the Western Power Network over the short and medium term
- setting requirements for, and planning for, emergency situations requiring load reduction and system restart
- coordinating planned outages of generation and transmission systems for maintenance

3.2.2.3 Control centre administration and management

Control centre administration and management represents 9% of forecast transmission network operations expenditure. This activity provides leadership and strategic direction to the transmission operations areas and provides the building, security, communications and cleaning services to the East Perth Control Centre.

3.2.2.4 SCADA operations

SCADA operations represent 6% of forecast transmission network operations expenditure. Transmission SCADA operations support, maintain and operate the transmission SCADA on an ongoing basis to provide the communications and control infrastructure for the SOCC to effectively operate the power system. The transmission SCADA is the primary tool the control centre uses to safely and reliably operate the power system. Loss of any SCADA systems operability or data visibility means complete reliance on automatic protection schemes for the protection of plant.

Note that this activity is for the operation of the SCADA system; maintenance of the SCADA and communications software and hardware is captured in the SCADA and communications regulatory category of operating expenditure.

3.2.3 Non-revenue cap services

In AA3 we will spend $17 million, 4% of forecast transmission network operating expenditure, on non-revenue cap services. These services are defined in section 9.2.2 of the AAI and were previously labelled non-reference services.

Non-revenue cap services are provided at the request of customers on a fee for service basis. These services do not relate to the provision of reference services and are therefore not included as part of the revenue cap calculation for the AA3 period. Customers who request these services pay for the costs incurred instead of these costs being borne by other customers through reference tariffs.

We provide transmission non-revenue cap services including:

- **network access applications** represent 82% of forecast transmission non-revenue cap expenditure. This activity includes the processing costs associated with applications for access to the Western Power Network, including new and modified connection points. Typical customers, such as new mine loads or generators, bear all the costs associated with progressing through the application process, as required by the current Applications and Queuing Policy and the standard Electricity Transfer Access Contract. These fees cover the process up until an application has reached the point of becoming an access offer or capital works are required. The schedule of applicable fees is contained in section 6 of the Price List, published annually by Western Power, see Appendix F.1: 2012/13 Price list of the proposed revisions to the Access Arrangement.
- **transmission line relocations** represent 14% of forecast transmission non-revenue cap expenditure. This activity includes the processing and quotation costs associated with applications to relocate transmission assets (66 kV or above) on the Western Power Network. Customers of these services include main roads as part of the black spot project to improve road safety and reduce car / pole interactions, or shopping centre developers who may need to remove assets that would impede development. These fees fully recover:
  - the process up until capital works are required (project enquiry stage) and labour costs for projects that do not proceed to completion
  - feasibility estimates
  - works that do not result in any additions to the asset base
- **work in the vicinity of power lines** represents 2% of forecast transmission non-revenue cap expenditure. This activity includes the assessment and, where necessary, installation of safety precautions required to work safely in the vicinity of our assets includes marking and insulation of aerial conductors.
- **customer network switching** represents 2% of forecast transmission non-revenue cap expenditure. This activity includes the isolation or de-energisation of a section of the Western Power network at the request of a customer (for example, to enable safe movement of a high load or safe working within the vicinity of a Western Power asset)

These services respond to the needs of transmission-connected customers and therefore tend to have a high correlation to general economic activity in the state.

A breakdown of AA3 forecast transmission non-revenue cap services operating expenditure by activity is shown in Table 13 and Figure 17.

Table 13: AA3 transmission non-revenue cap services expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Network access applications	2.6	2.6	2.8	3.0	3.3	14.2
Transmission line relocations	0.4	0.5	0.5	0.5	0.5	2.3
Work in the vicinity of power lines	0.1	0.1	0.1	0.1	0.1	0.3
Customer network switching	0.1	0.1	0.1	0.1	0.1	0.3
Non-revenue cap services total	**3.1**	**3.2**	**3.4**	**3.6**	**3.9**	**17.2**

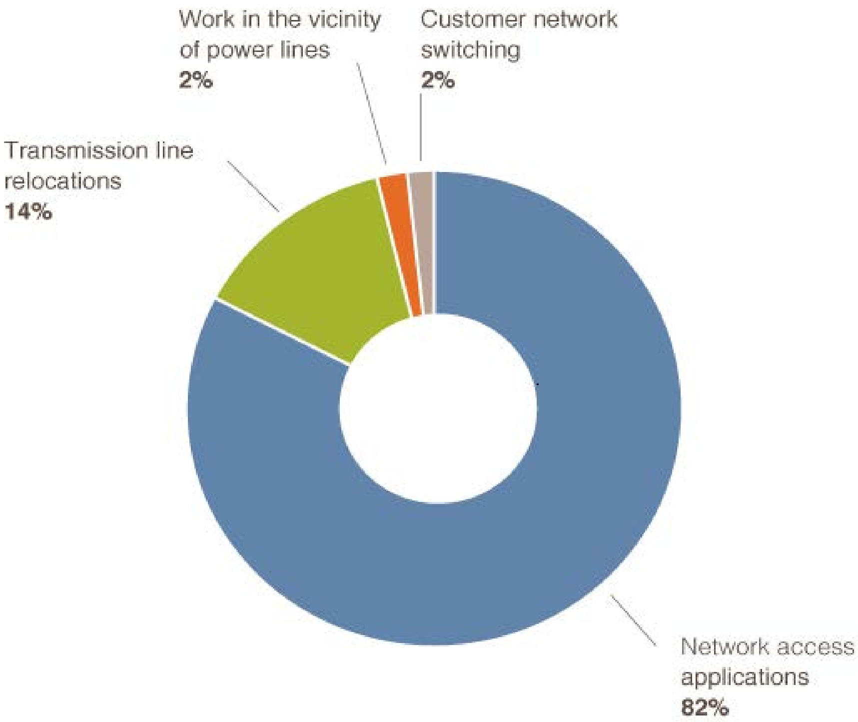

Figure 17: AA3 transmission non-revenue cap services expenditure by activity

3.3 Other operating expenditure

In AA3 we will spend $66 million, 15% of forecast transmission network operating expenditure, on non-recurring operating expenditure.

We have forecast specific non-recurring transmission operating expenditure activities. These activities tend to be one-off, project based or occur for a discrete time period and are therefore excluded from the base year roll-forward approach to forecasting recurrent network operating expenditure as described in chapter 7.2.1 of the AAI.

AA3 transmission non-recurring operating expenditure comprises:

- *network control services* – payments for generation or demand side management in constrained sections of the network to enable us to efficiently defer major capital investments
- *removal of redundant transmission assets* – removal of line and pole assets that are no longer in service which will ensure public safety and remove maintenance requirements

3.3.1.1 Network access applications

Network control services represent 90% of forecast transmission non-recurring operating expenditure. Network control services (also referred to as network control services (NCS)) allow Western Power to procure generation or demand side management in localised areas of network constraint and thereby defer the need for more costly network augmentation.

Localised generation or demand reduction that can be dispatched in response to network contingencies at peak times can assist in deferring capacity augmentation. This generation or demand reduction is located where it has the ability to reduce transmission line loading after a contingency, avoiding dangerous overloads and allowing secure operation of the power system while deferring the need for additional energy transportation capacity. As load continues to grow, the net present cost of providing annual network control services may exceed the net present cost of providing transmission network reinforcement.

The cost of network control services can vary considerably depending whether the procured generation or demand side management is already a market participant in possession of capacity credits. We have forecast the cost of network control services by:

- determining the capacity of service in MW required in each financial year to maintain power system security. This required power system simulations to establish the increase in capacity as demand grows
- estimating the amount of service that will need to be dispatched each year. This will increase with demand growth and will drive an increase in the cost for the service over time
- estimating the balance of fixed and variable costs to be paid by Western Power. Service providers may be eligible for capacity payments from the Independent Market Operator, the amount of that payment is expected to influence the network control services that we will need to fund. The forecast costs assume the service is provided by diesel fuelled generation that receives a capacity payment funding 75% of its fixed cost

In AA3 we will spend $59 million addressing network constraints through the use of network control services. The specific locations requiring network control services in AA3 are shown in Table 14.

Table 14: AA3 transmission network control services by location ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Network control services total	11.0	4.7	10.2	13.4	20.1	59.4

3.3.1.2 Transmission line relocations

Removal of redundant transmission lines represents 10% of forecast transmission non-recurring operating expenditure. This program is to remove sections of transmission lines that have been decommissioned and will no longer be required in the transmission network. It seeks to address our safety obligations by reducing the potential for unassisted pole failures on assets that are not in service and therefore not being maintained under business as usual pole management practices.

In AA3 we will spend $7 million removing wood pole line sections that are no longer required, as shown in Table 15. These comprise:

- Muja – Yornup/Collie 71 line – with the decommissioning of Yornup substation in 2007/08 (due to its poor condition), the section of the line between Collie and Yornup was decommissioned and is to be removed during AA3. Western Power has retained the section of line between Muja and Collie to maintain supply to the Collie town site and surrounding areas
- Muja – Boddington 81 line – the building of the Shotts-Wells Terminal 330 kV line alongside this line rendered it redundant
- Cannington – Kalamunda 81 line section – the area was reconfigured with the line being reconnected into different substations. This made certain sections of the line redundant

- Forrestfield – Midland Junction 81 line section – the area was reconfigured with the line being reconnected into different substations. This made certain sections of the line redundant

Removing these line sections will assist in reducing the unassisted wood pole failure rates to levels that are comparable with the national industry benchmark. Such failures can cause personal injury and property damage (see section 2.1.1).

Table 15: AA3 transmission removal of redundant lines expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Transmission line decommissioning and removal	3.0	2.5	0.8	0.7	0.0	6.9

4 Distribution operating expenditure

Distribution operating expenditure covers work to operate and maintain the distribution network assets on the Western Power Network.

In AA3 we will spend $1.673 billion on distribution operating and maintenance activities which are necessary to ensure the continuous provision of covered services for customers.

As set out in chapter 7 of the AAI, our distribution network operating expenditure is segregated into the following high level categories: maintenance, operations, customer services and billing, and other (non-recurring) operating expenditure. The detailed and high level categories of expenditure are shown in Table 16.

Table 16: AA3 forecast distribution network operating expenditure ($ million real at 30 June 2012)

AA3 expenditure by category	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of total
Preventative routine	43.2	45.4	48.1	50.8	54.8	242.4	14.5%
Preventative condition	63.6	66.7	70.5	63.3	68.1	332.3	19.9%
Corrective deferred	30.4	31.9	33.6	35.4	38.0	169.3	10.1%
Corrective emergency	81.6	85.3	89.7	94.3	101.1	452.0	27.0%
Maintenance	**218.8**	**229.3**	**242.0**	**243.8**	**262.1**	**1,196.0**	**71.5%**
Network operations	15.7	16.7	17.9	19.0	20.3	89.6	5.4%
Non-revenue cap services	14.9	15.3	16.0	16.8	17.9	80.9	4.8%
SCADA and communications	5.4	5.6	5.9	6.2	6.7	29.9	1.8%
Smart grid	4.4	3.6	4.4	5.9	7.4	25.7	1.5%
Reliability operations	2.0	2.1	2.2	2.3	2.5	11.0	0.7%
Operations	**42.3**	**43.3**	**46.5**	**50.3**	**54.7**	**237.1**	**14.2%**
Metering	20.2	21.0	21.8	22.6	23.4	108.9	6.5%
Call centre	7.3	7.8	8.2	8.7	9.2	41.2	2.5%
Distribution design and estimation quotations	4.2	4.3	4.6	4.8	5.0	23.0	1.4%
Guaranteed service level payments	2.5	3.0	3.4	3.9	4.4	17.3	1.0%
Customer services	**34.3**	**36.1**	**38.1**	**40.0**	**42.0**	**190.4**	**11.4%**
Non-recurring operating expenditure	8.0	10.0	10.2	10.4	10.9	49.5	3.0%
Other	**8.0**	**10.0**	**10.2**	**10.4**	**10.9**	**49.5**	**3.0%**
Distribution network operating expenditure	303.5	318.7	336.8	344.4	369.7	1,673.0	100.0%
Less non-revenue cap services	14.9	15.3	16.0	16.8	17.9	80.9	4.8%
Distribution operating expenditure to be recovered from reference tariffs	**288.6**	**303.4**	**320.7**	**327.7**	**351.9**	**1,592.1**	**95.2%**

4.1 Maintenance

In AA3 we will spend $1.196 billion, 71% of forecast distribution network operating expenditure, to maintain the distribution network.

We deliver our maintenance activities through four distinct categories:

- *preventative routine* – routine asset inspection cycles and related work
- *preventative condition* – responsive works based on asset condition
- *corrective emergency* – responsive works based on a network emergency and in-service failures
- *corrective deferred* – follow-up works after emergency network repairs

REGULATORY OBLIGATIONS

We are obliged to maintain our network assets to maintain provision of reliable covered services, to the appropriate level of quality and in a safe manner in accordance with the following key pieces of legislation:

- *Electricity Act 1945* and *Electricity Regulations* under the Act
- *Electricity (Supply Standards and System Safety) Regulations 2001** require that we must ensure that, so far as is reasonable and practicable, activities are carried out *in such a way as to provide for the safety of persons, including employees of and contractors to* Western Power
- *Electricity Industry Act 2005*
- *Technical Rules* clause 1.8.2 (c) which requires the *management, maintenance and operation of the transmission and distribution systems to minimise the number and impact of interruptions or service level reductions to Users*
- *Network Reliability and Quality of Supply Code 2005* (*clause 10) where we must, so far as is reasonably practicable, reduce the effect of any interruption on a customer*

Specific obligations affecting inspection activities include:

- *Energy Safety Order 01-2009* which affects our

  pole top inspections and line patrols

  pole base inspection and treatment
- vegetation management clearance zones set out in AS/NZS 7000:2010 Overhead line design - Detailed procedures and the Office of Energy Safety WA guidelines* must be maintained; this necessitates periodic inspections and quality checks in conjunction with contract clearing works

In order to meet these obligations we must undertake distribution maintenance activities, including inspection and asset monitoring, to prevent asset degradation and thereby reduce the frequency and occurrence of network outages.

* Available at: http://www.energy.wa.gov.au/2/2054/64/government.pm

* Available at: http://www.austlii.edu.au/au/legis/wa/consol_reg/esassr2001623/

4.1.1 Preventative routine maintenance

In AA3 we will spend $242 million, 14% of forecast distribution network operating expenditure, on preventative routine maintenance.

Preventative routine maintenance is a schedule of planned maintenance and inspection actions aimed at:

- predicting the onset of asset failure and identifying unsafe conditions through inspections
- detecting failures before they impact on asset function, network reliability and human safety
- maintaining expected asset life by ensuring assets are in good serviceable condition

The activities include monitoring, testing and inspecting equipment that is undertaken either at predetermined intervals or is initiated by equipment operations or asset condition. In addition to inspection and testing, lubrication and routine minor part replacement are carried out as part of preventative routine maintenance.

Conditions identified through preventative routine maintenance inspections inform works to be undertaken as part of:

- preventive condition maintenance
- asset replacement capital investment
- regulatory compliance capital investment

A breakdown of AA3 forecast distribution preventative routine maintenance expenditure by activity is shown in Table 17 and Figure 18.

Table 17: AA3 distribution preventative routine expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Power pole bundled inspections	19.8	20.8	22.1	23.4	25.2	111.3
Bulk globe replacement	6.4	6.7	7.0	7.4	7.9	35.4
Fuse and metal pole inspections	5.3	5.6	5.9	6.3	6.8	30.0
Vegetation inspections	4.0	4.2	4.5	4.7	5.1	22.6
Insulator siliconing	3.1	3.3	3.4	3.6	3.9	17.4
Ground mounted switchgear / substation inspections	2.6	2.8	2.9	3.1	3.3	14.8
Other	2.0	2.1	2.2	2.3	2.5	11.0
Preventative routine total	**43.2**	**45.4**	**48.1**	**50.8**	**54.8**	**242.4**

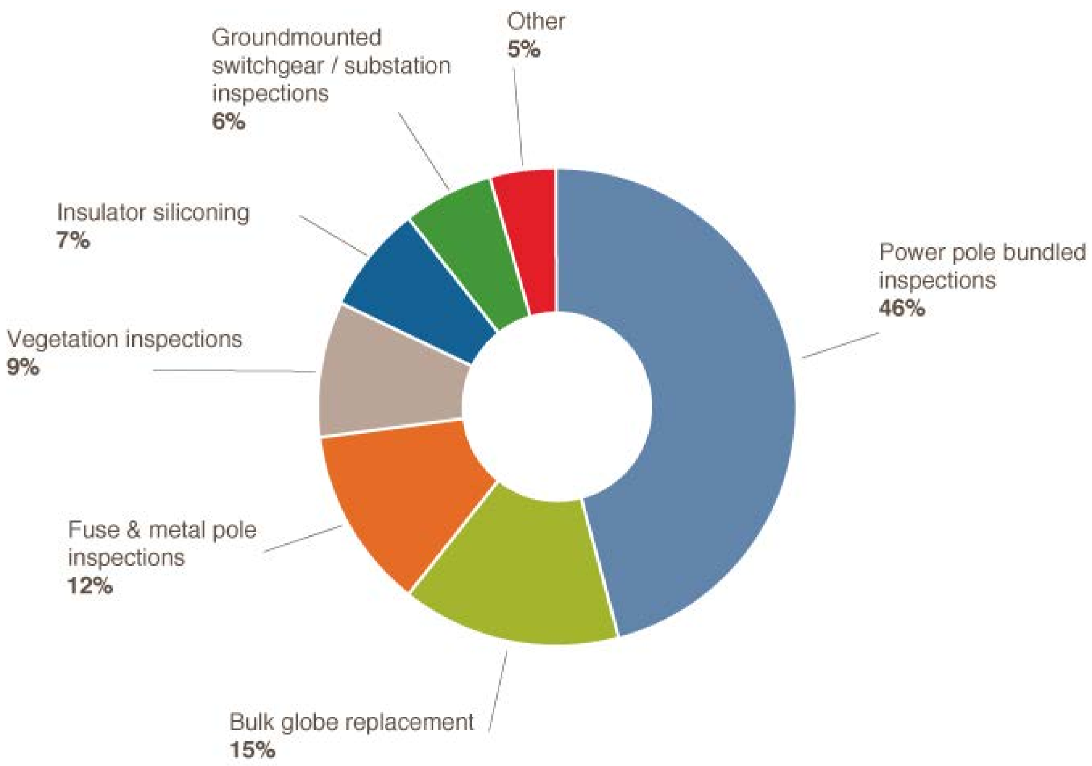

Figure 18: AA3 distribution preventative routine expenditure by activity

Each of these activities is discussed in the following sections.

4.1.1.1 Power pole bundled inspections

Power pole bundled inspections represent 46% of forecast distribution preventative routine expenditure. Under the power pole bundled inspections activity we inspect wood poles, concrete poles, pole top hardware, conductors, sectionalisers, reactors and pole top switches. Inspections assess the serviceability of the asset. Corrective replacement and reinforcement works are then scheduled and carried out under preventative condition maintenance or asset replacement activities.

Wood poles are our highest risk pole population in the network. Effective management of wood poles, pole top equipment, conductors and conductor accessories is critical to operating the Western Power Network. We operate a condition based asset management regime monitoring the condition, and therefore serviceability, of the pole and pole top asset population on a four year inspection cycle. In order to gain efficiencies of scale, we contract for this work across both transmission and distribution poles where it is possible to do so.

Serviceability is assessed by two main methods:

- serviceability and pole strength – if the serviceability index is greater or equal to one, the pole is assessed as serviceable. Poles with a serviceability index smaller than one are earmarked for replacement or reinforcement
- conditions – other conditions on the pole, pole top equipment, conductors and conductor accessories such as pole splits, burns and corrosion are assigned a condition severity. We prioritise work to be done through our preventative condition program based on condition severities

The serviceability index has been updated in accordance with *Energy Safety Order 01-2009*. The new serviceability index takes into consideration the residual strength, the loading the pole is subjected to, the fire risk associated with the location, whether it is a road crossing pole and whether the pole supports flammable assets such as transformers. The new methodology significantly increases the number of poles considered unserviceable.

Despite significant improvements over the AA1 period, our unassisted pole failure rate remains higher than the rest of the Australian electricity industry. We have been progressively enhancing our wood pole management practices bringing the current bundled pole inspection program up to standards of good electricity industry practice. This is expected to assist in bringing the unassisted pole failure rate in line with good electricity industry practice by the AA4 period.

Outcomes of power pole bundled inspections inform works to be undertaken in:

- preventive pole maintenance (operating expenditure)
- pole replacement and pole reinforcement (asset replacement capital expenditure)
- carrier replacement, bushfire mitigation wires down, pole top replacement in higher fire risk areas and drop out fuse replacement (regulatory compliance capital expenditure)

4.1.1.2 Bulk globe replacement

The bulk globe replacement program represents 15% of forecast distribution preventative routine expenditure. We undertake this program to reduce streetlight faults and ensure our streetlight asset data is up to date. We adopted the bulk globe replacement program approximately 20 years ago as a preventative maintenance strategy to cost effectively reduce the number of streetlight faults and improve reliability of this service. Replacing globes during their expected life prevents faults from occurring due to expired / burnt globes which account for approximately 70% of all reported streetlight faults.

During AA2 we moved from a four year to a three year inspection cycle following the results of a review into the effectiveness of this program. Changing to a three year cycle has already resulted in reductions to globe failure compared to historical fault levels.

4.1.1.3 Fuse and metal pole inspections

The pole inspections for metal poles and fuse pole clearing represent 12% of forecast distribution preventative routine expenditure.

Metal pole inspections

We inspect all metal power poles, metal streetlight poles and wiring rectification work for metal streetlight poles. This activity involves:

- preventative routine inspections of all metal power poles and metal streetlight poles that are over 15 years old
- wiring rectification work for metal streetlight poles
- rust treatment of corroding poles that are still mechanically sound to extend service lives

Metal poles are conductive and pose an electric shock hazard. These activities will support public safety by identifying and rectifying, where it is possible to do so, corroded metal power poles, faulty wiring components and corrosion contained in metal streetlight poles.

Incidents have been reported where members of the public have received electric shocks from metal power poles and metal streetlight poles. These shocks have been highlighted by Energy*Safety*. The likelihood of electric shocks will be greatly reduced by the work performed under this program as it will help identify and rectify defects before they lead to electric shocks.

We will be completing a larger volume of inspections than usual in 2011/12 ($5.7 million of non-recurrent costs) to clear a backlog of inspections. In 2012/13, the volume of metal pole inspections will return to sustainable levels.

Fuse pole clearing

This activity involves clearing vegetation away from the base of poles with fuses installed on them. This reduces the likelihood of a fire resulting from red-hot fuse fragments falling to the ground when a fuse operates. Under the vegetation strategic management plan, fuse pole clearing is to be completed on an annual basis prior to 15 November as part of the bushfire readiness program.

STEP CHANGE IN 2012/13

The annual volume of fuse pole clearing is reducing by approximately 11,200 to 18,915 from 2012/13, resulting in a $0.3 million decrease in annual expenditure.

As part of the vegetation strategic management plan, we have taken account of the cross dependency with vegetation inspections and also the anticipated savings achieved through the fire safe fuse asset replacement program due for completion in 2011/12.

In extreme and high fire risk areas we are replacing expulsion drop-out fuses with fire safe fuses. Installation of fire safe fuses is aimed at reducing the risk of fires around fuse poles and the need to undertake widespread fuse pole clearing. However, due to the large number of poles in the network, this continuous clearing program is needed to continue into the future, albeit at a much lower rate, to aid in addressing significant residual bushfire risks.

4.1.1.4 Vegetation inspections

Vegetation inspection represents 9% of forecast distribution preventative routine expenditure. We inspect vegetation to ensure it remains outside the defined clearance zone so as not to interfere with the safe, reliable supply of electricity to customers. Inspection identifies vegetation that is either currently growing, or likely to grow, within the clearance zone before the next inspection.

This activity forms the first part of our overall vegetation strategic management plan, the objective of which is to:

- ensure vegetation is kept outside the overhead line clearance zone at all times
- have full visibility at all times of cutting and inspection programs through auditing and data management
- achieve long term reduction of vegetation clearance expenditure via sucker management[25] and removal of trees within the management zone

In particular, this activity aims to ensure all distribution lines designated as being in extreme and high fire risk areas are inspected and cleared by 15 November each year (the start of the bushfire season). The inspection program ensures compliance with defined vegetation clearance zone obligations is maintained.

4.1.1.5 Insulator siliconing

Insulator siliconing represents 7% of forecast distribution preventative routine expenditure. Insulator siliconing is a key preventative maintenance practice that helps avoid pole top fires. Pole top fires are associated with electricity networks that use timber construction of high voltage networks. Several hundred pole top fires occur every year and have the potential to cause significant damage to the network and to public safety.

Insulator siliconing involves:

- applying silicon grease (Sylgard) to insulators (or removing old silicon)
- line washing associated with insulator siliconing

We wash insulators and then apply a Sylgard compound[26] to reduce the effect of surface pollutants on performance of the asset and to minimise surface tracking, television interference and flashover events. The Sylgard silicone solution can be applied under live conditions on distribution HV insulators. Once Sylgard has been applied, we can reduce the need for costly washing of insulators by up to three insulator washes per year. This is a medium-term strategy (5-10 years) to prevent pole top fires as the application of Sylgard has to be repeated periodically due to declining effectiveness, particularly in high pollution or coastal areas with a high salt content in the air, such as Geraldton.

This activity reduces the risk of leakage currents and pole top fires, in turn helping to maintain current levels of network safety and reliability, minimise the likelihood of bushfire incidents related to pole top fires and enable us to comply with relevant statutory obligations.

[25] Sucker management is the removal and poisoning of re-growth from tree stumps. When this activity is not undertaken, the regrowth from tree stumps can impact on the easement clearance space. Early sucker management prevents more costly activities to remove vegetation regrowth.
[26] This compound is non-conductive and has hydrophobic properties.

4.1.1.6 Ground mounted switchgear / substation inspections

Inspections of ground mounted and overhead switchgear and substations represent 6% of forecast distribution preventative routine expenditure.

Overhead system inspections

Overhead system inspections involve:

- inspecting assets related to the overhead network that are not categorised by any other preventive routine maintenance activity, including for overhead inspection on a request basis
- conducting inspections recommended consequent to unassisted pole failure investigations
- performing aerial patrols of high voltage lines deemed to be *at risk* prior to the bushfire season
- undertaking a quality assurance audit on 5% of the volumes of inspections carried out

In 2007, we experienced 5,400 public complaints, with more than 50% relating to our overhead network system. Historically, these complaints and public concerns required site inspection of our network assets to ensure public safety. Failing to conduct a site inspection of this nature will often result in poor or even wrong decision making which can jeopardise our company image, system reliability and compromise public safety.

Aerial inspections prior to the bushfire season are becoming good electricity industry practice, particularly after the recent Black Saturday Victorian bushfires and the findings of the Royal Commission into those fires. Our meetings with Victorian utilities in April 2010 reinforced this view. The risk of our overhead assets initiating bushfires can be reduced by inspecting and rectifying high risk lines prior to the onset of the bushfire season. This method has been identified as a cost effective measure to reduce bushfire risk.

Overhead bundled switch gear

We conduct annual inspections of overhead switchgear based on the manufacturer's information. Failure to inspect the capacitor banks, regulating transformers and reclosers will lead to a higher probability of asset failure which will in turn impact the quality of supply. In this event, the assets will not achieve their expected lifetime and so require premature replacement with the associated increase in cost. Poor asset performance will lead to poor reliability, and may create safety hazards for both the general public and Western Power employees.

Between 2003/04 and 2007/08 the number of asset related conditions recorded from this inspection activity totalled 1,528. All these conditions were severity three or worse which implies that these assets have a high probability of failing within 12 months after inspection. Given the condition history, we are increasing focus on this activity in AA3 to enable us to effectively monitor the integrity of our capacitor banks, regulating transformers and reclosers.

Ground mounted substation bundled inspection

Substation network assets need to be inspected, tested and monitored to ensure they are functional and remain in service. By having substation asset inspection information available in the form of conditions and associated condition severity, we can plan and prioritise maintenance work prior to asset failure.

Substation bundled inspections comprise the routine inspection of all ground-mounted switchgear housed in indoor substations, compounds, kiosks and LV distribution frames and completion of minor repairs as specified in the technical maintenance requirements. Quality assurance audits are undertaken on 5% of the volumes carried out.

General substation inspections (Level A) are carried out once every two years with CBD substations being inspected annually due to the criticality of the load they supply. The inspection schedule is carried out on an ongoing basis throughout the year.

This activity:

- enables us to plan and prioritise maintenance work prior to asset failure to gain cost efficiencies as we execute our asset management responsibilities
- ensures that Western Power and the public will be better protected from the potential consequences of destructive asset failures on the distribution network including fire, environmental incidents and electric shock
- maintains continued compliance with our regulatory asset management obligations

4.1.1.7 Other

The following activities are individually less than $2 million per year or 4% of forecast distribution preventative routine maintenance expenditure. Nonetheless, these activities make vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Overhead switchgear bundled inspections (3.2%) – rectifying conditions on overhead switchgear including pole top switch disconnectors, sectionalisers, reclosers and line isolators identified during inspections or other maintenance tasks in the Perth metropolitan, south and north country regions. These activities are required to ensure that other overhead and protective devices operate correctly or these conditions may cause other assets to fail in service. Conditions not corrected within the recommended timeframe may lead to unnecessary and costly failure in service and a corresponding increase in the corrective maintenance category expenditure.
- Miscellaneous overhead (1.1%) – inspecting assets related to the overhead network that are not categorised by any other preventative routine maintenance activity, including for overhead inspections undertaken on request, conducting inspections recommended consequent to unassisted pole failure investigations, performing aerial patrols of high voltage lines deemed to be ‘at risk’ prior to bushfire season, and undertaking quality assurance audits on 5% of the volumes of inspections carried out. Aerial inspections prior to bushfire season are becoming common good electricity industry practice, particularly after the recent Black Saturday Victorian bushfires and the findings of the Royal Commission into those fires. Our meetings with Victorian utilities in April 2010 reinforced this view. The risk of our overhead assets initiating bushfires can be reduced by inspecting and rectifying suspect lines prior to the onset of the bushfire season. This method has been identified as a cost effective measure to reduce bushfire risk.
- Pole base inspection and treatment (0.1%) – this activity involves the inspection and chemical fungicide treatment of wooden poles. It includes those poles located within substations and poles on decommissioned transmission lines that are yet to be disassembled. We carry out inspections and treatment every four years starting 10 years from the date a given pole was installed. The aim is to detect a potential failure before failure of the asset and thereby seek to minimise the transmission pole failure rate. In addition, pole base inspection and treatment ensures compliance with the recommendations listed under *Energy Safety Order 01-2009* regarding management of poles.
- Pole top inspection and line patrols (0.1%) – identify and report on obvious defects including structural damage, faulty earthing, accurate asset tag (nameplate)

information, defaced nameplates, fauna on structures, evidence of third party damage, clearances and easements, insulators, and conductors. Inspections are carried out via both helicopter and ground patrol. These inspection activities help ensure that service standards to customers are maintained by detecting line asset conditions that could compromise supply reliability, as well as mitigating public safety issues. In addition, pole top inspections and line patrols ensure our compliance with the recommendations listed under *Energy Safety Order 01-2009* regarding management of poles.

4.1.2 Preventative condition

In AA3 we will spend $332 million, 20% of forecast distribution network operating expenditure, on preventative condition maintenance.

Preventive condition maintenance is a schedule of planned maintenance actions performed as a result of conditions or defects primarily identified during the preventive routine maintenance programs.

As identified in sections 2.1.1, for a number of performance indicators including the distribution pole integrity index, we are still on a pathway to meeting best industry practice benchmarks or reducing average asset age for our network assets most at risk of failure. This makes it essential for us to operate an extensive program of preventative condition maintenance to minimise safety risks, reduce system downtime and maintain reliability. The ideal preventive maintenance program would prevent all critical asset failures before they occur.

Preventative condition maintenance will help us to efficiently minimise costs by:

- increasing the effective service life of maintained assets and therefore long term capital replacement costs
- performing maintenance under a scheduled work scenario rather than more costly emergency repair

A breakdown of AA3 forecast distribution preventative condition maintenance expenditure by activity is shown in Table 18 and Figure 19.

Table 18: AA3 distribution preventative condition maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Line easement vegetation maintenance	28.8	30.3	32.1	34.0	36.7	162.0
Pole maintenance	27.8	29.1	30.6	21.1	22.6	131.2
Earthing maintenance	2.5	2.6	2.8	2.9	3.2	14.0
Ground mounted switchgear maintenance	1.7	1.8	1.9	2.0	2.1	9.4
Minor asset replacement	1.1	1.2	1.2	1.3	1.4	6.2
Other	1.7	1.8	1.9	2.0	2.1	9.4
Preventative condition total	63.6	66.7	70.5	63.3	68.1	332.3

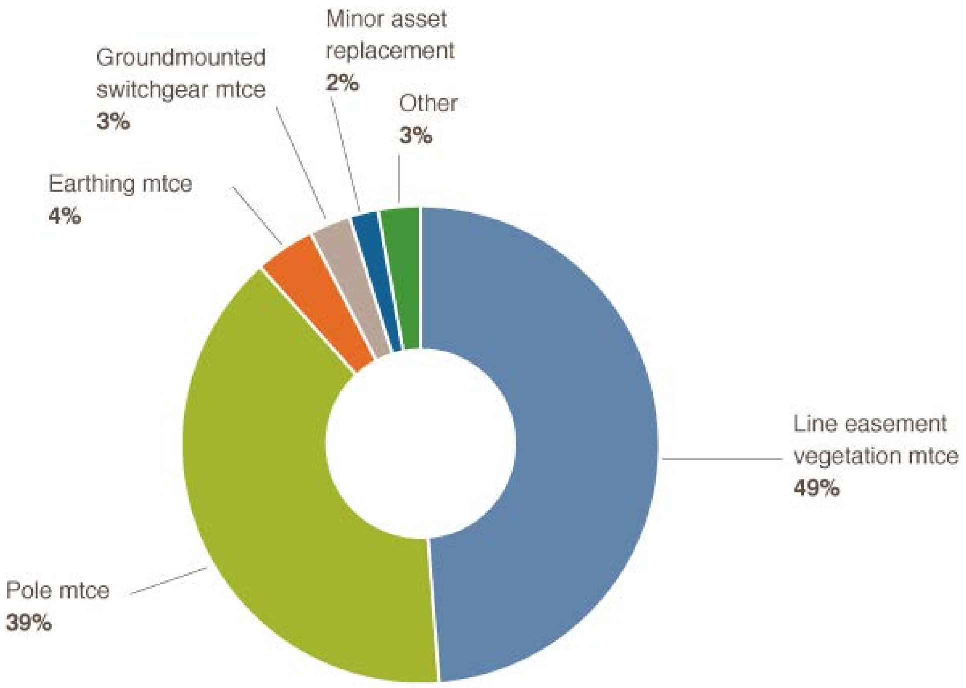

Figure 19: AA3 distribution preventative condition maintenance expenditure by activity

Each of these activities is discussed in the following sections.

The segregation of operating and maintenance tasks into categories is important in our planning to optimise what can be somewhat random tasks at the mercy of external forces (for example, accidents, faults and extreme weather). In an electrical distribution environment, these circumstances can bring extreme safety, fire, property damage, supply reliability and other discrete risks. Thus, the previous two sections have explained our distribution preventative maintenance activities – these are the more predictable tasks. The following two sections explain the activities which make up our more unpredictable distribution related emergency response maintenance. Section 4.1.3 and section 4.1.4 explain the activities which make up Western Power's responsive works to address network emergencies and in-service failures.

4.1.2.1 Line easement vegetation maintenance

Line easement vegetation maintenance represents 49% of forecast distribution preventative condition maintenance expenditure. Vegetation can grow into distribution lines or make contact with lines under high winds. The line easement vegetation maintenance program reduces the risk of this by cutting vegetation in the vicinity of the lines. Vegetation is cut to a level that ensures that no vegetation will be in the safety clearance zone until the start of the next inspection cycle.

Our volumes are prioritised by the risk assigned to each maintenance zone. As part of the vegetation strategy each of the risks are assigned a cycle time for which inspection must be carried out. The volumes are forecast based on the cycle time, the number of assets and a find rate of inspection which identifies the spans that require cutting. This program runs all year, but has the specific objective of finishing all extreme and high fire risk zones before 15 November each year, the beginning of the bushfire season. Medium fire risk zones are cut on a two year cycle and low fire risk zones are cut on a three year cycle.

This activity helps maintain safety and reliability of the network by reducing the risk of network outages and/or bushfires caused by vegetation coming into contact with distribution lines. Additionally, the *Code of Practice* for the Establishment and Maintenance of Clearances between Vegetation and Power Lines details the requirements of vegetation management as per the *Electricity Act 1945* and the *Electricity Regulations 1947*.

4.1.2.2 Pole maintenance

Pole maintenance represents 39% of forecast distribution preventative condition expenditure. We identify and complete condition-based pole maintenance activities through inspections. The maintenance inspections can reveal requirements for minor pole top maintenance, burnt or broken line tap repair, retrofitting high pollution insulators, verifying customer reports of termites in poles and any subsequent treatment. The necessary condition-based pole maintenance identified from inspections includes:

- pole and pole top maintenance
- burnt and broken line tap repair
- conductor related maintenance work
- damage and bird caging of wires maintenance - including the re-tensioning of conductors where substandard height exists and no capital investment solution is required under regulatory compliance
- insulators replacement
- white ant treatment

We assign conditions a severity ranking. Our network management practices provide that severity 1 conditions need to be repaired within two weeks; severity 2 conditions need to be repaired within three months while severity 3 conditions need to be repaired within 12 months.

Responding to these conditions in a timely way best ensures our assets can remain in service for their full design lives and helps avoid interruptions to customer supply or public safety incidents arising from pole failures.

STEP CHANGE IN 2012/13

During the AA2 period, we were addressing the backlog of pole conditions from the AA1 period. In 2010/11, a data validation exercise was undertaken to first ensure the conditions in our asset management databases were correct and had not been addressed through other programs. From 2011/12 to 2014/15 we will be undertaking a significant volume of pole maintenance activities to clear 23,581 outstanding conditions over and above the sustainable forecast asset condition find or defect rate of 13,700 per annum. This means we will be undertaking a total of $26.1 million of non-recurrent expenditure on pole maintenance across 2012/13 to 2014/15.

In 2015/16 we will be able to reduce annual expenditure by $8.7 million to normal levels, based on an estimated defect rate of 13,700 per annum.

4.1.2.3 Earthing maintenance

Earthing maintenance represents 4% of forecast distribution preventative condition expenditure. This activity rectifies *conditions* relating to earthing systems identified from inspections or other preventative routine maintenance tasks in the Perth metropolitan, south and north country regions.

Conditions relating to the earthing of substation and plant assets identified during routine or ad hoc inspections require rectification to ensure that protective devices operate correctly or these conditions may cause other assets to fail in service. Conditions not corrected within the recommended timeframe may lead to unnecessary and costly failure in service and a corresponding increase in the corrective maintenance category expenditure.

Specific work types include repair, remediation or replacement of earths associated with pole mounted equipment (down earths) and distribution substations (earth pits and grading rings).

Regular maintenance of earthing assets ensures the network remains safe and functional in line with Western Power's licence and regulatory obligations. This activity will enable Western Power to effectively maintain its earthing associated with substations and pole mounted plant in good condition.

Inadequate earthing can result in power quality issues, incorrect operation of upstream protective devices and voltage rise of earthed metalwork within customer premises. It is also important to adequately earth ground-mounted and pole mounted switchgear to ensure the safety of Western Power operators during manual local switching operations.

4.1.2.4 Ground mounted switchgear maintenance

Ground mounted switchgear maintenance represents 3% of forecast distribution preventative condition expenditure. This activity rectifies fault conditions and or instances of non compliance relating to ground mounted switchgear identified from inspections or other preventative routine maintenance tasks in the Perth metropolitan, south and north country regions.

The asset classes in this category include HV and LV ground mounted switchgear housed in indoor substations, compounds, kiosks and LV distribution frames. Specific work types include repair or replacement of these asset classes.

Ground mounted switchgear asset conditions identified during routine or ad hoc inspections require repair or replacement of the asset prior to failure in service. Conditions not corrected within the recommended timeframe may lead to unnecessary and costly failure in service and a corresponding increase in the corrective maintenance category expenditure.

Continued delivery of this activity will assist us to:

- improve safety by minimising the number of lost time incidents due to operational incidents
- efficiently minimise future capital investment by adequately maintaining existing assets
- operate a safe, reliable and efficient network
- reduce the likelihood of catastrophic failures associated with ring main units

4.1.2.5 Minor asset replacement

Minor asset replacements represent 2% of forecast distribution preventative condition maintenance expenditure. Minor asset conditions noted during routine or ad hoc inspections require rectification to ensure assets do not fail in service and do not represent a safety hazard to the general public. Conditions not corrected within the recommended timeframe may lead to unnecessary and costly failure in service and a corresponding increase in the corrective maintenance category expenditure.

This activity includes rectification of *conditions* relating to underground and overhead equipment identified from inspections or other preventive routine maintenance tasks in the Perth metropolitan, south and north country regions. Specific work types include (but are not limited to) replacement of luminaires, stay wires and electrical services.

4.1.2.6 Other

The following activities are individually less than $1 million per year or 2% of forecast distribution preventative routine maintenance. Nonetheless, these activities make vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Overhead switchgear maintenance (1.3%) – this activity rectifies conditions relating to overhead switchgear identified from inspections or other preventative routine maintenance tasks to ensure that other overhead and protective devices operate correctly or these conditions may cause other assets to fail in service. Conditions not corrected within the recommended timeframe may lead to unnecessary and costly failure in service and a corresponding increase in the corrective maintenance category expenditure. The asset classes in this category include pole top switch disconnectors, sectionalisers, reclosers and line isolators.
- Substation maintenance (1.1%) – rectifying fault conditions and/or maintenance of the substation grounds including general access, correction of ground erosion, inoperable locks, missing signage and corrosion of enclosures identified from inspections or other preventative routine maintenance tasks in the Perth metropolitan, south and north country regions. This activity is necessary to ensure the timely rectification of conditions relating to ground-mounted substations fault conditions. Conditions are prioritised as follows: severity 1 conditions need to be repaired within two weeks; severity 2 conditions need to be repaired within three months while severity 3 conditions need to be repaired within 12 months.
- Streetlight maintenance (0.2%) – maintenance of streetlights identified from inspections or other preventative routine maintenance tasks. As our streetlight poles are in public areas, any condition that could lead to structural failure or electrical failure resulting in the metal pole becoming energised can cause serious safety hazards and even death. Streetlight globe faults are addressed under the bulk globe replacement activity as part of preventative routine expenditure.
- Underground system maintenance (0.1%) – this activity rectifies fault conditions and/or instances of non-compliance relating to underground equipment identified from inspections or other preventative routine maintenance tasks. The asset classes in this category include underground equipment including underground residential distribution (URD) pillars and service domes, underground pits and link boxes. Specific work types include general restorative maintenance and ground restoration around URD pillars and levelling of underground pits.

4.1.3 Corrective deferred maintenance

In AA3 we will spend $169 million, 10% of forecast distribution network operating expenditure, on corrective deferred maintenance.

Following an emergency maintenance situation, works that are not urgent are rescheduled for attention using standard workforce practices as part of corrective deferred maintenance. This is based on our practice of efficiently minimising costs by reducing, where possible, works conducted in more costly emergency situations in favour of completing those same works at lower cost in a more controlled and planned situation. The deferred activity is usually completed within the same financial year as the corresponding emergency event or events.

Activities consist of asset repairs, environmental cleanups and emergency follow ups. If we do not carry out corrective deferred maintenance of assets, service standards will be adversely affected eventually impacting on the supply to customers. This is because the purpose of corrective deferred maintenance is to make more complete repairs to equipment or network that was attended to and made safe during an emergency situation so that it no longer represents an emergency situation. If the more permanent repairs are not made, there will be a higher risk of future failures.

A breakdown of AA3 forecast distribution corrective deferred maintenance expenditure by activity is shown in Table 19 and Figure 20.

Table 19: AA3 distribution corrective deferred maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Emergency follow-up overhead maintenance	9.0	9.4	9.9	10.4	11.2	49.8
Emergency follow-up underground maintenance	3.7	3.8	4.0	4.2	4.6	20.3
Data correction	3.4	3.6	3.8	4.0	4.3	19.2
Power quality investigation and repair	2.77	2.90	3.05	3.21	3.44	15.37
Investigative / triggered maintenance	2.5	2.6	2.7	2.9	3.1	13.8
Pole / vehicle interaction	1.9	2.0	2.1	2.2	2.3	10.5
Environmental cleanup	1.7	1.8	1.9	2.0	2.1	9.4
Emergency follow-up asset replacement	1.5	1.6	1.6	1.7	1.9	8.3
Graffiti cleanup	1.1	1.1	1.2	1.2	1.3	5.9
Service order investigation issues	1.0	1.1	1.1	1.2	1.3	5.7
Other	1.99	2.09	2.21	2.33	2.50	11.11
Corrective deferred total	**30.4**	**31.9**	**33.6**	**35.4**	**38.0**	**169.3**

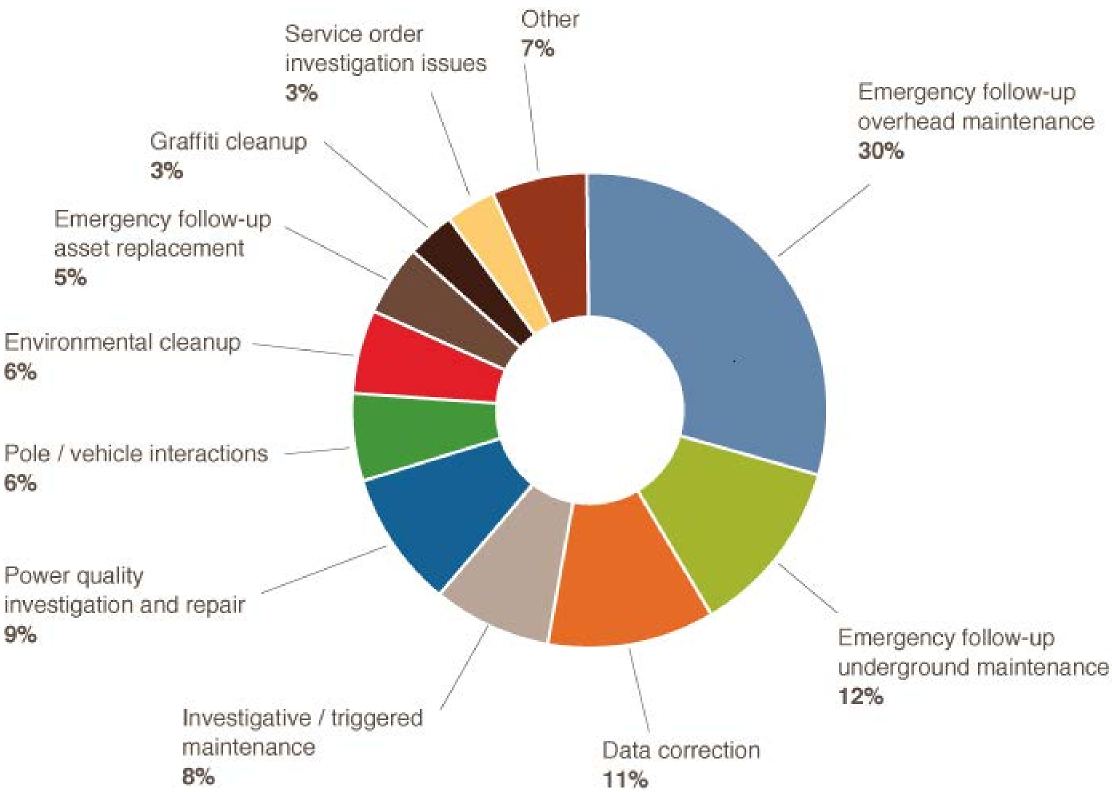

Figure 20: AA3 distribution corrective deferred expenditure by activity

Each of these activities is discussed in the following sections.

4.1.3.1 Emergency follow up overhead maintenance

Emergency follow up and corrective maintenance of overhead assets represents 29% of forecast distribution corrective deferred maintenance expenditure. This activity involves permanently repairing temporarily repaired overhead network assets that result from corrective emergency works. It aims to maximise safety, improve reliability and maintain expected life of the asset. Not replacing minor assets or making temporary fixes permanent can lead to:

- deteriorating reliability
- a compromise in the safety of the general public and our employees
- the degradation of the network’s efficiency

This can pose significant risk to the functioning of the business and hence corrective follow up action upon the affected assets is essential to maintain the integrity of the system

4.1.3.2 Emergency follow up underground maintenance

Emergency follow up and corrective maintenance of underground assets represents 12% of forecast distribution corrective deferred maintenance expenditure. This expenditure considers the costs associated with the permanent repair of temporarily repaired underground network assets that result from corrective emergency work. Not replacing minor assets or making temporary fixes permanent can lead to:

- deteriorating reliability
- a compromise in the safety of the general public and our employees
- the degradation of the network's efficiency

This can pose significant risk to the functioning of the business and hence corrective follow up action upon the affected assets is essential to maintain the integrity of the system.

4.1.3.3 Data corrections

Data corrections represent 11% of forecast distribution corrective deferred maintenance expenditure. This is a business as usual activity with steady numbers of data corrections received on a daily basis. Deferring this work is not practical, as failure to address the data corrections would cause the number of existing conditions to increase, which would result in further corrupt, incomplete or erroneous data. The efficiency of the investment in asset strategies is heavily dependant on the availability of accurate data. If data corrections are not actioned in a timely manner, the efficiency of this investment would also decease, as more work would be required to address the data errors due to changes in the network over time.

4.1.3.4 Power quality investigation and repair

Investigative and triggered maintenance represents 8% of forecast distribution corrective deferred maintenance expenditure. This activity includes the corrective maintenance of network assets identified through the trouble call system or from inspections or other preventive routine maintenance tasks. These tasks include rectification of sub-standard overhead service lines and wires down, replacement of service fuses and investigation of various network hazards.

The trouble call system is used to raise service calls for incidents that are reported by the general public or are automatically system initiated.

4.1.3.5 Investigative / triggered maintenance

Power quality investigations and repair of minor defects represent 7% of forecast distribution corrective deferred maintenance expenditure. This activity is part of our power quality complaints handling process to rectify the cause of customer power quality complaints. In accordance with regulatory obligations as specified in the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*[27] *Technical Rules 2007 (WA)* and the *Electricity Act 1945 (WA),* Western Power is required to respond to all customer complaints.

In particular, under Part 4 section 24 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, Western Power must within 20 working days complete the investigation of a complaint and report the results to the customer concerned. Where remedial works are required, all resources required are sourced in accordance with Western Power's corporate and procurement policies to ensure timely rectification of PQ issues.

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[27] Available at: http://www.energy.wa.gov.au/cproot/594/2557/D04%20Electricity%20Industry%20(Network%20Quality%20and%20Reliability%20of%20Supply)%20Code%202005.pdf

This activity reactively investigates power quality complaints from customers and undertakes rectification works if required. This activity is part of a list of other activities which supports the key performance indicator ‘number of customer complaints per 100,000 customers’.

4.1.3.6 Pole / vehicle interaction

Pole / vehicle interactions represent 6% of forecast distribution corrective deferred maintenance expenditure. These repairs arise from third party vehicle hits on our network require immediate action to correct the resulting loss of supply and public safety risk. Our prompt response to these collision incidents efficiently minimises customer outages, public risk and vehicle traffic disruption.

4.1.3.7 Environmental cleanup

Environmental cleanup represents 6% of forecast distribution corrective deferred maintenance expenditure. This activity is required for the efficient management of pollution and waste attributed to our operations.

Pollution includes incident based events such as transformer oil spills in distribution substations and field locations and vehicle hydraulic leaks. Longer term site management required under the contaminated sites program for significant pollution on Western Power locations from historical activities such as storage of fuel and pesticides. Generation of waste occurs through the decommissioning of network plant.

The activities responding to our environmental obligations include:

- controlled waste – we are required under the *Environmental Protection Act 1986 (WA)* to protect the environment from any waste that could be expected to gain access to any portion of the environment and result in pollution. Therefore, all efforts shall be made to ensure controlled waste is not discharged during any Western Power activity
- oil spill response – failure to act will be a breach of the *Environmental Protection Act 1986* and will damage corporate reputation (fines up to $1m corporation, $500K individual, daily $200K corporate, daily $100K individual plus up to 5 years imprisonment). It would also lead to a breach of the *Contaminated Sites Act 2003*. Oil spills often impact private residences (for example stained driveways, damage to lawns). Failure to act will lead to complaints and insurance claims
- contaminated sites – investigation, management and remediation of our contaminated sites are a requirement under *Contaminated Sites Act 2003*. We reported approximately 80 sites to the Department of Environment and Conservation (DEC) in 2007 as either known or suspected contaminated sites. Following classification by the DEC (expected in 2010/11) we will be required to enter a program of investigation and remediation. Failure to comply would lead to prosecution under the *Contaminated Sites Act 2003*
- PCB disposal – disposal of PCBs in an unauthorised manner would result in breaches of the *Environmental Protection Act 1986* including the *Environmental Protection (Controlled Waste) Regulations 2004*[28] and *Environmental Protection (Unauthorised Discharges) Regulations 2004*[29] and risk prosecution under these regulations

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[28] Available at: http://www.austlii.edu.au/au/legis/wa/consol_reg/epwr2004575/
[29] Available at: http://www.slp.wa.gov.au/statutes/regs.nsf/3b7e5f26432801b348256ec3002c128c/5dbdd334de60e0fe48256e550029757e/$FILE/Environmental%20Protection%20(Unauthorised%20Discharges)%20Regulations%202004.PDF

Non-compliance with *Environmental Protection Act 1986* and *Contaminated Sites Act 2003* could result in penalties up to $1 million for corporate and $250,000 for individuals, plus daily penalties of $250,000 and $50,000. This compliance program over the next seven years will allow us to comply with environmental legislation.

4.1.3.8 Emergency follow up asset replacement

Emergency follow up and corrective maintenance represents 5% of forecast distribution corrective deferred maintenance expenditure. This activity includes the replacement of minor assets or temporarily repaired network assets that result from corrective emergency type work. The proposed expenditure allows for the permanent repair of temporarily repaired assets that result from corrective emergency type work (excluding overhead and underground assets which are addressed via other activities). It aims to maximise safety, improve reliability and maintain expected life of the asset by making permanent repairs to damaged assets that have had temporary repairs carried out under emergency situations.

Not replacing minor assets or making temporary fixes permanent can lead to:

- deteriorating reliability
- a compromise in the safety of the general public and our employees
- the degradation of the network's efficiency

This can pose significant risk to the functioning of the business and hence corrective follow up action upon the affected assets is essential to maintain the integrity of the system.

4.1.3.9 Graffiti cleanup

Graffiti cleanup represents 3% of forecast distribution corrective deferred maintenance expenditure. Graffiti cleanup is an ongoing maintenance activity which involves the removal of graffiti from distribution network assets. All reported graffiti on Western Power network assets removed in accordance with the requirements of the Premier's Circular - *Premier's Circular 2006/04 Graffiti Vandalism Removal Standards*[30] issued 12/06/2006 and reviewed 12/06/2008 states: *all public sector bodies are required to adopt a 48-hour graffiti vandalism removal standard (from the time of reporting), with immediate removal if the graffiti is racist or obscene.*

We are involved in strategies to engage with the community, the Office of Crime Prevention and other utilities to reduce graffiti. There is also an expectation that the unit cost of removal will decrease due to the volume of graffiti incidents.

4.1.3.10 Service order investigation issues

Service order investigation issues represent 3% of forecast distribution corrective deferred maintenance expenditure. The purpose of this activity is to understand the issues relating to asset failures and to recommend, if necessary, corrective action required on the asset. This may also take the form of corrective action required for a particular asset group. It provides the early awareness of potential specific asset type problems relating to an asset or developing network issues.

4.1.3.11 Other

The following activities are individually less than $1 million per year or 2% of forecast distribution corrective deferred maintenance expenditure. Nonetheless, these activities make

[30] Available at: http://www.dpc.wa.gov.au/GuidelinesAndPolicies/PremiersCirculars/Pages/Default.aspx?page=6

vital contributions to minimising public safety risk and maintaining service standards by ensuring that the network components relevant to each activity are in good working order.

- Data maintenance (1.9%) – maintenance of asset data, which is not part of a specific project, for example, transformer replacements, consumer service wires, pole replacements (through faults or scheduled maintenance programs), removal of poles that don't exist in the field from the geographic information system (GIS), and adding poles that do exist into the GIS. This activity provides accurate data recorded on Western Power's assets in the information systems, within 10 days of receipt of the as-constructed or identified data. Ensuring asset information is up to date and accurate enables us to maximise efficiency when determining replacement of end of life assets, developing safe switching programs including planned outage information and enhancing network safety and reliability.
- Dial Before You Dig service (1.8%) – this provides the public with information of Western Power's underground network via requests made through the 'Dial Before You Dig' service. It enables Western Power and third parties to comply with *Worksafe Regulation 3.21 Excavation* by providing accurate asset location information. It also ensures we protect our underground assets from accidental damage by third parties.
- Asset damage unknown perpetrator (1.1%) – repair of our assets that are damaged as a result of accidents or deliberate vandalism by a third party. There is often little scope for coordination with other work and the cost is not able to be recovered, mainly because the perpetrator cannot be identified. The main outcome of this activity is to repair the damage giving higher priority to issues that affect public safety and supply continuity.
- Asset damage known perpetrator (0.6%) – this involves the repair of our assets that are damaged as a result of a customer's actions and where the cost is able to be recouped from the customer. Public safety, supply restoration and public amenity concerns drive our timely responses to cases of graffiti, vandalism and the like.
- Television interference repairs and investigations[31] (1.0%) – this addresses customer complaints due to television interference (TVI) faults caused by the distribution network. Customer TVI complaints are required to be investigated, as per section 24 within the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, under specific limits outlined within section 2.2.6 of *Technical Rules* 2007. This is one of a list of activities that supports Western Power's 'number of customer complaints per 100,000 customers' KPI.

4.1.4 Corrective emergency maintenance

In AA3 we will spend $452 million, 27% of forecast distribution network operating expenditure, on corrective emergency maintenance.

Corrective emergency maintenance includes maintenance activities carried out to immediately restore supply or make a site safe following equipment failure usually as a result of unplanned equipment failures, an accident or inclement weather. This type of work generally occurs without warning and is performed immediately to establish restoration of supply, ensure safety to the public and personnel, and prevent further damage to equipment.

[31] Under section 2.3.6 of the Technical Rules Western Power 'must respond to all complaints regarding electromagnetic interference in a timely manner and undertake any necessary tests to determine whether or not the interference is caused by equipment forming part of the transmission and distribution systems... If the complaint is justified, the Network Service Provider must, as soon as reasonably practicable, take any necessary action to reduce the interference to below the maximum prescribed levels.'

Corrective emergency maintains network performance in an efficient manner by deferring works that are not urgent to be carried out as part of standard working schedules rather than by more costly emergency response units.

The activities include monitoring, testing and inspecting equipment that is undertaken either at predetermined intervals or is initiated by equipment operations or condition. This work typically includes visual inspection, testing, lubrication and routine minor part replacement.

STEP CHANGE IN 2011/12

We are increasing the combined expenditure on corrective emergency and corrective deferred maintenance by $3 million from 2011/12

In 2010/11 there was a significant 20% decrease in overall fault rates upon the network. This low fault rate is inconsistent with the previous four years fault activity. Analysis of the fault information shows that approximately two-thirds of this decrease is related to a lower number of faults caused by lightning activity, equipment failures (including pole top fires) and other known causes directly or indirectly associated with the weather.

In 2011/12 we are stepping expenditure levels back up to historical levels. The current fault rates for the first quarter of 2011/12 have increased compared to 2010/11 supporting our analysis.

The impact of the increase in preventative maintenance and capital expenditure is expected to reduce corrective deferred and corrective emergency expenditure over time. However, as discussed in section 2.1.1, we are still on a pathway to meeting industry benchmarks for our network assets most at risk of failure including distribution wood poles and carriers.

A breakdown of AA3 forecast distribution corrective emergency maintenance expenditure by activity is shown in Table 20 and Figure 21. This shows that the majority of corrective emergency maintenance relates to primary response. Collectively, all other activities account for less than half this category.

Table 20: AA3 distribution corrective emergency maintenance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Primary response	57.1	59.7	62.8	65.9	70.7	316.2
Storms	11.1	11.6	12.2	12.8	13.6	61.3
Streetlight faults	7.8	8.2	8.6	9.1	9.7	43.3
Emergency response generator deployment	2.8	2.9	3.1	3.2	3.5	15.5
Truck items and minor consumables	2.1	2.2	2.3	2.4	2.6	11.7
Post-fault line patrols	0.7	0.8	0.8	0.8	0.9	4.0
Corrective emergency total	**81.6**	**85.3**	**89.7**	**94.3**	**101.1**	**452.0**

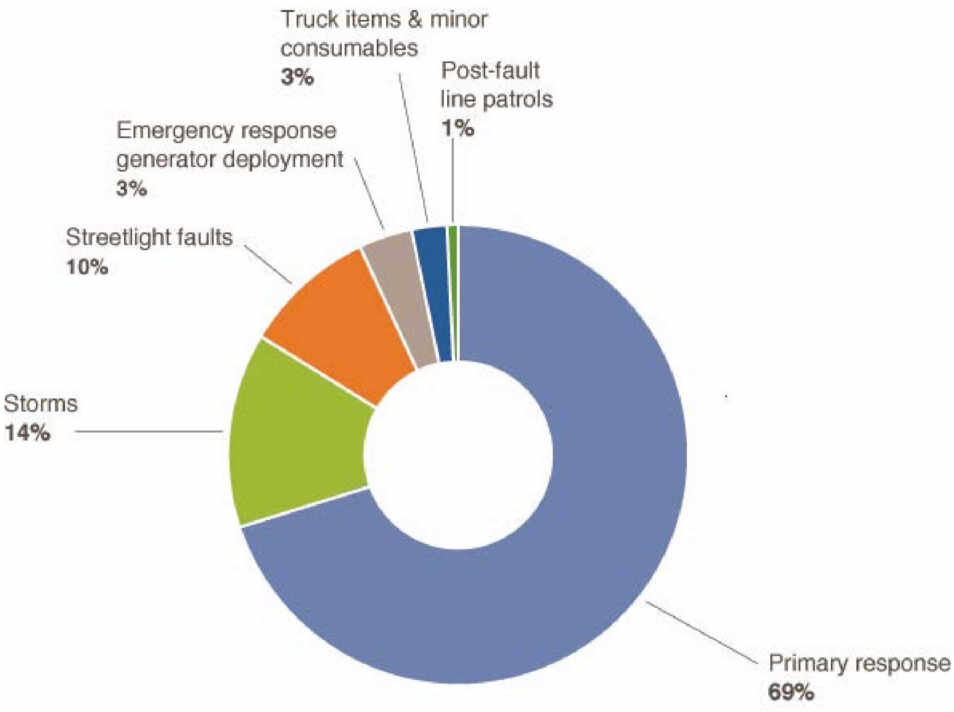

Figure 21: AA3 distribution emergency corrective expenditure by activity

Each of these activities is discussed in the following sections.

4.1.4.1 Primary response

Primary response assistance represents 70% of forecast distribution corrective emergency maintenance expenditure. This activity involves resource centre personnel providing assistance to the network operations control centre fault crew in response to faults and hazards on the distribution network. This includes all works and incidents driven from the trouble call system, the overhead costs associated with the fault response, primary response and network investigations teams and material and equipment costs.

Actions include making safe, restoring supply and effecting a minor permanent fix (fuses, service leads) or temporary fix where a permanent fix is not possible or efficient at the time.

Western Power must carry out immediate repairs to faulty and hazardous assets so as to ensure:

- public safety is not compromised
- supply is restored in an expedient manner
- assets do not suffer further damage

Western Power is required to ensure public safety and power supply reliability. The immediate response under this activity supports compliance with these obligations.

Where extensive damage has resulted, such as poles and conductors being down, the primary response group will restore as many customers as the situation permits, and make safe the area. After they have done this, standard crews can then move in on a planned basis to carry out final repairs through the corrective deferred maintenance activity.

4.1.4.2 Storms

Emergency storms response represents 14% of forecast distribution corrective emergency maintenance expenditure. This activity covers all primary response groups, fault response assistance and corrective repair work (both temporary and permanent repair) associated with a network operations control centre declared crisis level 3 or 4. Such work is entirely reactive, driven by extreme weather or other emergency that would result in a level 3 or 4 crisis declared by the control centre.

4.1.4.3 Streetlight faults

Emergency streetlight fault repairs represent 10% of forecast distribution corrective emergency maintenance expenditure. The need and timing for repairing faulty streetlights and streetlight cable faults is based on the times prescribed in the *Customer Charter*[32], proposed Access Arrangement and the *Code of Conduct for the Supply of Electricity to Small Use Customers*[33]*.* These set the repair time to be within:

- five working days in the metro areas
- five working days in the regional centres
- nine working days in the rural areas

Our immediate response provides:

- compliance with the response and repair of streetlight faults in accordance with the Western Power *Customer Charter* and Access Arrangement, and the *Code of Conduct for the Supply of Electricity to Small Use Customers*
- improved street illumination level and hence improved public safety
- customer satisfaction

4.1.4.4 Emergency response generator deployment

Emergency response generator deployment accounts for 3% of forecast distribution corrective emergency maintenance expenditure. Western Power maintains a fleet of emergency response generators (ERG) available on standby. The ERG provides an alternate means of supply for unplanned outages and planned outages. The number of units held in the fleet varies with additional units being held during summer months due to increased risk of over overloading and insufficient distribution transfer capacity in the network.

For 2010/2011 there are 13 units held throughout the year, with an additional eight units being added to the fleet between December 2010 and March 2011. The generator units range in size between 38 kVA to 1,250 kVA.

Maintaining an adequate ERG fleet enables Western Power to best meet its service reliability obligations during both planned and unplanned outage situations.

[32] Available at: http://www.westernpower.com.au/customerservice/customercharter/index.html
[33] Available at: http://www.erawa.com.au/cproot/6425/2/20080304%20Code%20of%20Conduct%20for%20the%20Supply%20of%20Electricity%20to%20Small%20Use%20Customers%202008%20-%20Gazetted%2026%20February%202008.pdf

4.1.4.5 Truck items and minor consumables

Truck items and minor consumables for emergency response crews represent 3% of forecast distribution corrective emergency maintenance expenditure. This activity covers incidental items associated with corrective maintenance such as nuts, bolts, grease, wire ties and similar. The expenditure is for consumable materials used by the primary response crews and typically some stores are held in each work truck. The primary response crews provide assistance to network operations control centre fault crew in response to distribution network faults and hazards.

It is uneconomical to predict all minor items required to complete a task or to book out individual items post the fault situation. It is more efficient to carry a quantity of consumable items on all of the service trucks across the whole of the Western Power Network.

The items held with the field service vehicles do not have an expiry date and therefore will not deteriorate whilst awaiting use.

4.1.4.6 Post fault line patrols

Post fault line patrols account for 1% of forecast distribution corrective emergency maintenance expenditure. These involve line patrols after protective equipments trip and are usually done to ensure that a feeder or line is suitable and safe for reclose.

Adequate functioning of these assets is both critical and essential for the safe, reliable and efficient delivery of electricity to our customers. Poor asset performance and unavailability will lead to poor reliability, a compromise in the safety of the general public and our employees, and the degradation of efficiency.

4.2 Distribution operations

In AA3 we will spend $237 million, 14% of forecast distribution network operating expenditure, on operating the distribution network. Of this, $81 million will be contributed by customers receiving non-revenue cap services.

We deliver our operations activities through five distinct categories:

- *network operations* – provides centralised monitoring and control over the operation of the distribution network
- *non-revenue cap services* – customer driven requests that are not directly attributable to the provision of reference services and hence are paid for by the requesting customer
- *SCADA and communications* – carries all information and commands between network equipment and the control centre
- *smart grid* – operating expenditure associated with transitioning Western Power to the incorporation of smart meters and related new technologies
- *reliability operations* – operations and maintenance activities that are specialised for distribution network reliability and automation assets

4.2.1 Network operations

In AA3 we will spend $90 million, 5% of forecast distribution network operating expenditure, on network operations.

Our distribution network operations function centrally monitor and control how the distribution network operates and makes decisions about allowing network access for the purposes of maintenance, construction and commissioning of assets.

The outcomes of this function are to:

- maintain and prevent the deterioration of the network performance service
- reduce the likelihood of network incidents due to operator action or error
- reduce network outage and asset damage due to unbalanced loads on network assets
- maintain capability for field switching operation and full use of mobile dispatch for fault service restoration
- switching programmes delivered on-time to meet outage or network access requests

REGULATORY OBLIGATIONS

The network operations function complies with obligations under the *Technical Rules* including:

- section 2.3 – Obligations of Network Service Provider in relation to power system performance
- section 5.3 – Power system operation co-ordination responsibilities and obligations
- section 5.7 - Power system security operation and coordination
- section 5.10 - Power system operation support

A distribution network operation is a key contributor to achieving the distribution service standard benchmarks. The distribution service standard benchmarks which depend in part upon the network operations function include SAIDI and SAIFI. Performance against these measures in the AA2 period is included in chapter 3 of the AAI.

A breakdown of AA3 forecast distribution network operations expenditure by activity is shown in Table 21 and Figure 22.

Table 21: AA3 distribution network operations expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Network operations control centre	12.8	13.6	14.6	15.5	16.5	73.0
Control centre administration and management	2.3	2.5	2.7	2.8	3.0	13.3
SCADA	0.6	0.6	0.6	0.7	0.7	3.2
Network operations total	**15.7**	**16.7**	**17.9**	**19.0**	**20.3**	**89.6**

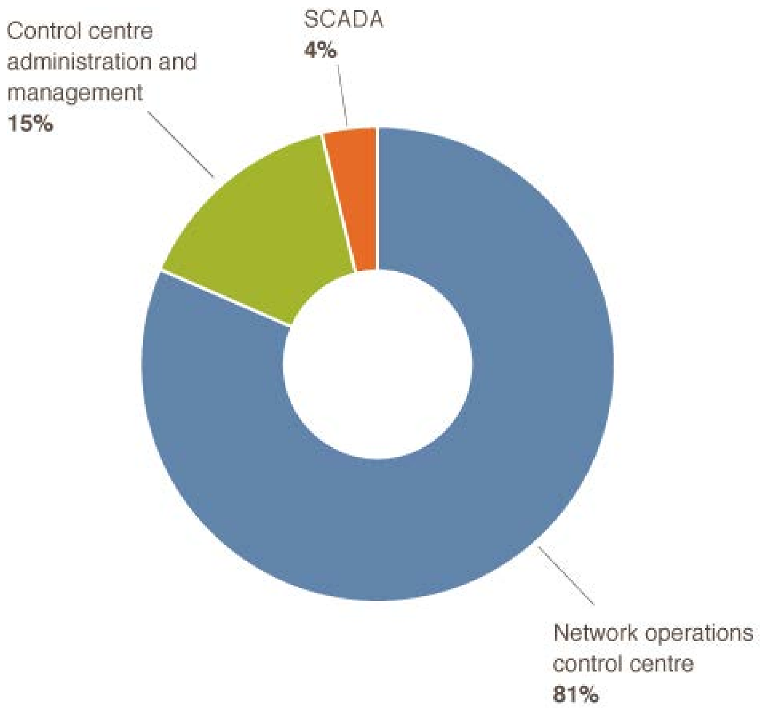

Figure 22: Distribution network operations expenditure in AA3 by activity

Each of these activities is discussed in the following sections.

4.2.1.1 Network operations control centre

The core activity of managing the Network Operations Control Centre (NOCC) accounts for 81% of forecast distribution network operations expenditure. NOCC is responsible for operating the distribution network. This 24 hour a day function ensures continuous power supply to the public from:

- proactive management actions – monitoring of the network, preparation and execution of switching programmes for planned work access, redistribution of network loads to minimise the risk of network failures, analysis of failure history and managing planned network access to minimise service disruption to the public and maximise safety to staff and the public
- reactive management actions – managing the service restoration of faults, coordination of field service restoration and emergency response coordination in adverse weather conditions such as storms, floods, bushfires

These activities help us to achieve our service standard benchmarks such as SAIDI and SAIFI.

4.2.1.2 Control centre administration and management

Control centre administration and management expenditure accounts for 15% of forecast distribution network operations expenditure. This activity provides leadership and strategic direction to NOCC whose mission is to undertake generation operation (commitment, dispatch, ancillary services), manage the operation of and facilitate access to the Western Power Network.

The expenditure forecast in this activity consists mainly of payroll and administration expenditure.

4.2.1.3 SCADA

The SCADA operations activity accounts for 4% of forecast distribution network operations expenditure. Distribution SCADA is the primary tool used by NOCC to safely and reliably provide access to the distribution network including management of the customer trouble call system support for both planned and unplanned distribution work.

Distribution SCADA operations support, maintain and operate the distribution SCADA system on an ongoing basis to provide the communications and control infrastructure for the network operations control centre to effectively operate the power grid.

4.2.2 Non-revenue cap services

In AA3 we will spend $81 million, 5% of forecast distribution operating expenditure, on distribution non-revenue cap services. These services are defined in section 9.2.2 of the AAI and were previously labelled non-reference services.

Non-revenue cap services are provided at the request of customers on a fee-for-service basis. These services do not relate to the provision of reference services and are therefore not included as part of the revenue cap calculation for the AA3 period. Customers who request these services pay for the costs incurred instead of these costs being borne by other customers through reference tariffs.

We provide distribution non-revenue cap services including:

- **Extended metering services** represent 51% of forecast distribution non-revenue cap expenditure. This activity includes metering services as set out in our ‘Service Level Agreement with Western Australian retailers’. This provides for services outside normal meter reads such as meter changes and testing, de-energisations, re-energisations, reconfigurations and meter related investigations.
- **high load escorts and surveys** represent 27% forecast distribution non-revenue cap expenditure. This activity provide for the safe transport of oversized loads through the Western Power Network and usually involves high load route surveys, lifting lines or switching the network off to accommodate high or wide loads to pass in close proximity to our infrastructure.
- **disconnection/reconnections** represent 15% of forecast distribution non-revenue cap expenditure. This activity includes the temporary disconnection of supply from the Western Power Network to enable safe work to take place (for example, renovation or re-wiring of house).
- **work in the vicinity of powerlines** represents 6% of forecast distribution non-revenue cap expenditure. This activity includes the assessment and, where necessary, installation of safety precautions required to work safely in the vicinity of our assets includes marking and insulation of aerial conductors.
- **temporary/ builders supply** represents 0.4% of forecast distribution non-revenue cap expenditure. This activity includes provision of a temporary supply of power to an unconnected site (for example a construction site) in advance of a permanent connection

A breakdown of AA3 forecast distribution non-revenue cap services expenditure by activity is shown in Table 22 and Figure 23.

Table 22: AA3 distribution non-revenue cap services by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Metering extended services	7.5	7.9	8.3	8.7	9.4	41.8
High load escort / High load survey	4.4	4.3	4.4	4.5	4.7	22.1
Disconnection / reconnection	2.2	2.3	2.4	2.5	2.7	12.2
Work in vicinity of power lines	0.8	0.8	0.9	0.9	1.0	4.5
Temporary / builders supply	0.1	0.1	0.1	0.1	0.1	0.3
Non-revenue cap services total	**14.9**	**15.3**	**16.0**	**16.8**	**17.9**	**80.9**

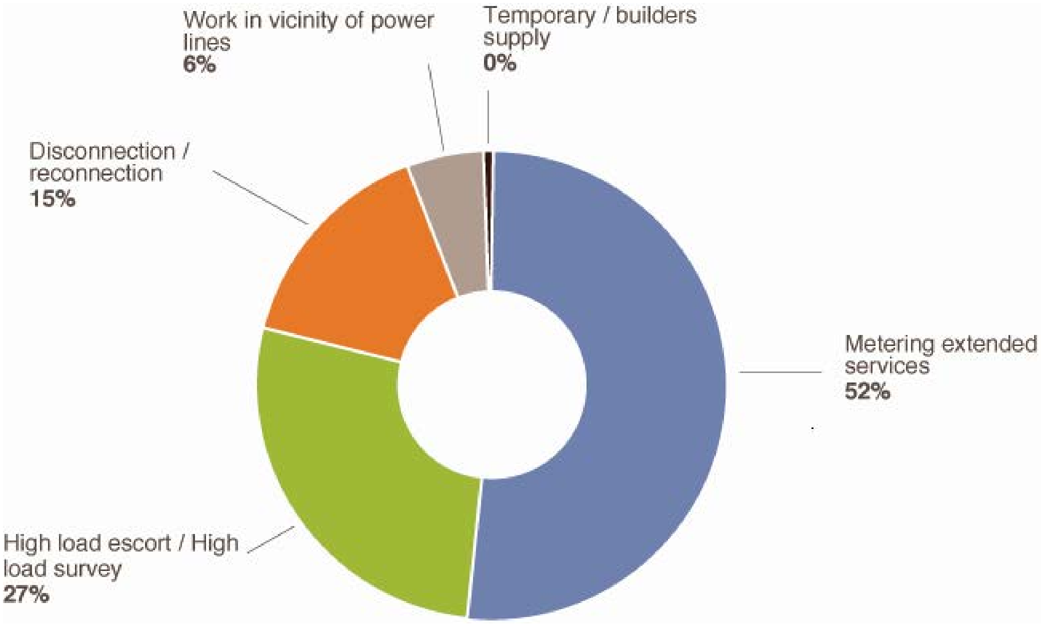

Figure 23: AA3 distribution non-revenue cap services expenditure by activity

4.2.3 SCADA and communications

In AA3 we will spend $30 million, 2% of forecast distribution network operating expenditure, on SCADA and communications operating expenditure.

The SCADA and communications activity provides the personnel and resources required to operate and maintain critical SCADA and communications systems. This activity also provides the operational fault and maintenance response capability to ensure that SCADA and communications systems remain functional and meet the relevant service and availability KPIs.

Distribution SCADA is an essential tool that we use to safely and reliably operate the power system. SCADA, in addition to its own component parts, relies heavily on communications links. Loss of any SCADA systems impacts operability and data visibility as follows:

- exposes primary plant to risk from small overloads – that is, above plant rating but below protection operating levels
- means emergency switching cannot be undertaken – for example, requests from FESA to turn off lines due to bushfire or third party hits to network infrastructure

- has potential for site security to be compromised as no fire alarm or door alarm visibility would be available
- means site safety is compromised as all switching has to be done on-site and the control centre has reduced visibility and coordination capability
- will impact on real time distribution system management modelling used in NOCC for contingency analysis
- can impact line run back schemes in SCADA
- may affect automatic sequence switching in SCADA for automatic restoration

Planning for distribution SCADA and communications expenditure is informed by the secondary system asset management plan and the SCADA and communications state of the network report. These documents are built upon each year to provide good data to drive efficient and effective asset management for SCADA and communications assets in line with good industry practices.

REGULATORY OBLIGATIONS

SCADA and communications expenditure focuses on meeting obligations for continuous network control and monitoring as outlined in section 3.2.1. This investment also plays a key role in ensuring we can meet compliance obligations related to the distribution network operations function, described in section 3.2.2, and to meet our minimum service standard benchmarks through remote monitoring and switching which dramatically decreases the time taken to respond to faults and has a direct impact on maintaining SAIDI.

A breakdown of AA3 forecast distribution SCADA and communications operating expenditure by activity is shown in Table 23 and Figure 24.

Table 23: AA3 distribution SCADA and communications expenditure ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Operations	3.8	4.0	4.2	4.5	4.8	21.3
Corrective maintenance	0.7	0.7	0.8	0.8	0.9	3.8
Planning	0.6	0.6	0.6	0.7	0.7	3.1
Routine maintenance	0.3	0.3	0.3	0.4	0.4	1.7
SCADA and communications total	**5.4**	**5.6**	**5.9**	**6.2**	**6.7**	**29.9**

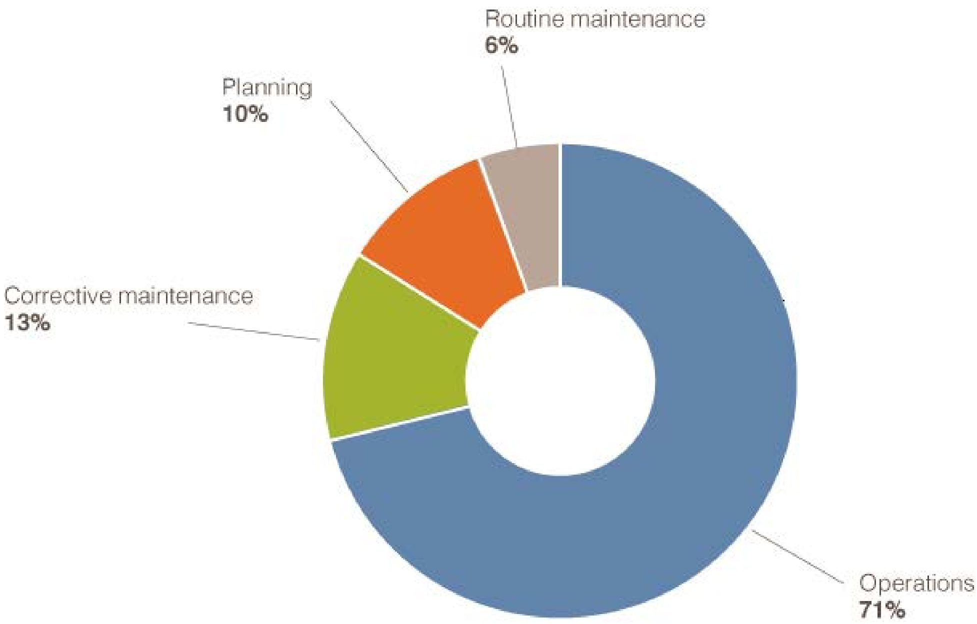

Figure 24: AA3 distribution SCADA and communications expenditure by activity

Each of these activities is discussed in the following sections.

4.2.3.1 Operations

The operations activity represents 71% of forecast distribution SCADA and communications operating expenditure. This comprises:

- maintaining the operations centres for the Western Power communications system at Mount Claremont and also the ENMAC SCADA Master Station equipment at East Perth control centre (EPCC)
- management of the licensing for the operating system and radio systems, communications site leasing and power costs

The operations activity does not include expenditure for operators to run the East Perth control centre or for market operations personnel. The ongoing increase to automated distribution assets will continue to contribute to operations staff workloads.

4.2.3.2 Corrective maintenance

This activity represents 13% of forecast distribution SCADA and communications operating expenditure. SCADA and Communications equipment must be maintained and operated to meet the availability requirements for protection, voice and data communications in order to monitor and control parts of the electrical network. The severity of the corrective maintenance is determined by operators and work is scheduled to meet regulatory obligations within required timeframes. Loss of visibility of a zone substation or remote pole top device may prevent operators from switching feeders, transformers and reclosers for daily load changes or for safely switching for planned or emergency work.

4.2.3.3 Planning

This activity represents 10% of forecast distribution SCADA and communications operating expenditure. This activity includes all of the planning and development necessary to develop and maintain strategic asset management plans for SCADA and communications equipment. It includes the analysis and production of the annual state of the network document and asset missions for existing and new assets.

This activity enables but does not fund works driven by capacity expansion, customer driven, reliability driven and regulatory compliance regulatory categories.

4.2.3.4 Routine maintenance

This activity represents 6% of forecast distribution SCADA and communications operating expenditure. Planned routine maintenance activities are required to maintain the SCADA and communications assets at the required level of availability.

SCADA and communications operations and maintenance activities contribute significantly to our capacity to maintain compliance with legislative obligations. The ongoing increase to automated distribution assets will continue to contribute to routine maintenance on these assets.

4.2.4 Smart grid

In AA3 we will invest an incremental $26 million operating expenditure to assist in the delivery of our smart metering infrastructure (SMI) and smart grid functionality to sections of the Western Power Network. This represents 1.5% of forecast distribution network operating investment.

This is the next step in our evolution towards building an intelligent network, a key component of our Network Investment Strategy, which aims to improve operational and capital efficiency and meet the changing needs of customers and stakeholders.

The activities and operating costs associated with deploying, configuring and managing smart meters is shown in Table 24 and Figure 25.

Table 24: AA3 distribution smart grid operating expenditure by activity ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Smart metering infrastructure	-	3.1	3.8	3.5	3.5	13.9
Smart grid pilot programs	-	0.1	0.2	2.0	3.4	5.8
Smart grid preliminary planning	4.0	-	-	-	-	4.0
Smart grid engagement	0.4	0.4	0.4	0.4	0.4	2.1
Total	**4.4**	**3.6**	**4.4**	**5.9**	**7.4**	**25.7**

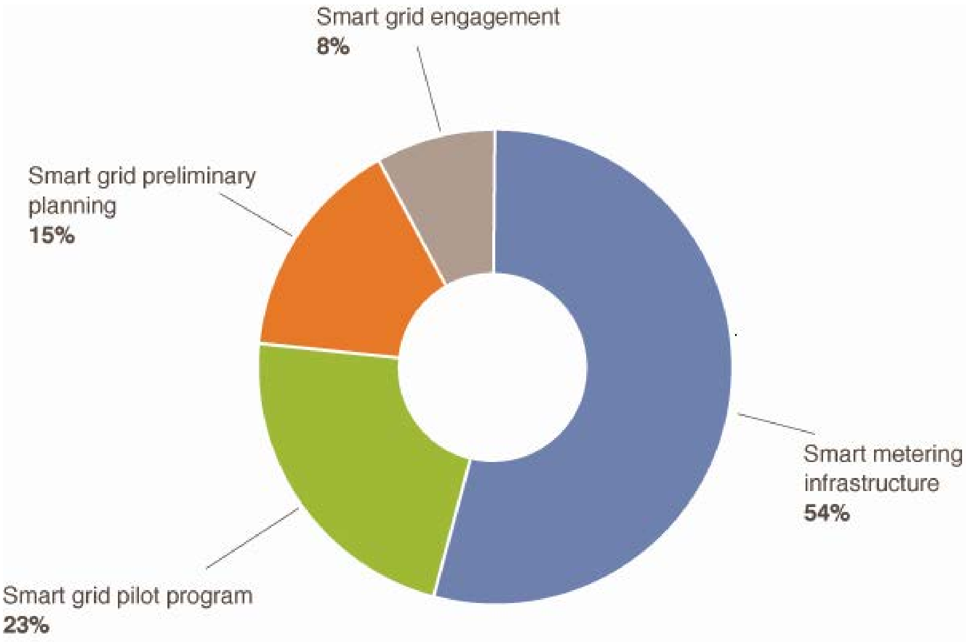

Figure 25: AA3 distribution smart grid expenditure by activity

Each of these activities is discussed in the following sections.

4.2.4.1 Smart metering infrastructure

In AA3 we will spend $14 million, 54% of forecast smart grid operating expenditure, to operate and support the smart grid control and monitoring system. In AA3 we have a unique opportunity to leverage the mandatory replacement of 280,000 non-compliant three phase meters. The smart meter deployment activity includes costs to:

- implement, operate and support the two way communications network to meet market and regulatory performance levels for existing and new customer and market services enabled by smart meters and smart grid technology
- implement and operate the smart grid control and monitoring system
- configure smart meters and associated two way communications
- implement, operate and support the communications enabled services comprising: customer in-home-display and customer home area network (HAN) portal support, critical peak pricing and Time of Use tariffs, load control, remote connection and disconnection, automated meter reading and distribution automation
- software licences for Network Management System (NMS), OSI Pi PQ data historian and customer portal support for 280,000 three phase smart meters and 52,000 new and replacement three phase smart meters
- a comprehensive broad reach smart metering awareness campaign to educate customers

To achieve early benefits to customers, deployment of the two way communications, SMI systems and processes will be undertaken in parallel to the smart meter deployment. This is one of the key learning's from Victoria's smart meter rollout and our own smart grid foundation program trials.

4.2.4.2 Smart grid pilot programs

In AA3 we will invest $6 million, 23% of forecast smart grid operating expenditure on pilot programs to investigate non-network alternatives to reducing peak demand and explore smart grid functionality.

AA3 pilot programs include costs for establishment of network peak demand reduction incentive schemes, direct load control programs and deployment of in-home displays to targeted customers for peak demand management.

4.2.4.3 Smart grid preliminary planning

In AA3 we will invest $4 million, 15% of forecast smart grid operating expenditure on preliminary planning activities.

This expenditure is required to define the scope of new products and services that will be enabled by smart meters including defining the technical and performance requirements. Included in these costs is further analysis of data from trials and pilot programs, preparation of specifications, preparation of architecture and security designs and tendering for metering and communications infrastructure.

4.2.4.4 Smart grid engagement

In AA3 we will invest $2 million, 8% of forecast smart grid operating expenditure on community engagement and education to maximise take-up of smart meter services and reduce peak demand.

The customer engagement and energy management education will support the deployment of in home displays and an energy portal. Prior to implementation of smart meters in a geographical region there will be broad reach communication to raise awareness about the new technology and the opportunities it provides to customers. This will be closely followed by engagement through the local media and in conjunction with local government to leverage existing sustainability programs, which has been shown to work effectively in the Perth Solar City program.

More specific engagement through community based social marketing will then be undertaken with existing community groups and at local events and festivals. This will include targeting individuals who are receiving a smart meter via direct mail to engaging directly with them to offer specific programs from which they are most likely to benefit.

4.2.5 Reliability operations

In AA3 we will spend $11 million, 0.7% of forecast distribution network operating expenditure, on reliability operations.

This activity enables us to respond to reliability faults such as those on distribution automation devices. Reliability operations work comprises operations and maintenance activities that are specialised for distribution network reliability and automation assets including, reliability initiated line patrols and automation maintenance request for repairs (RFR) and protection grading. This work is not complimentary to other distribution routine, corrective maintenance activities as different skills, spares and procedures apply.

Over time, we have been introducing more reliability automation assets onto the Western Power Network. Distribution automation devices have become a critical element in ensuring we meet our reliability of supply obligations.

A breakdown of AA3 forecast distribution reliability operations expenditure by activity is shown below in Table 25. Automation request for repairs make up 61% of expenditure, the remaining 39% of expenditure is for reliability driven line patrols.

Table 25: AA3 distribution reliability operations expenditure by activity

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Automation request for repairs	1.5	1.5	1.6	1.7	1.8	8.1
Reliability driven line patrols	0.5	0.5	0.6	0.6	0.6	2.9
Reliability operations total	**2.0**	**2.1**	**2.2**	**2.3**	**2.5**	**11.0**

4.2.5.1 Automation request for repairs

Automation maintenance request for repairs represent 74% of forecast distribution reliability operations expenditure. The automation support and maintenance operational expenditure relates to reactive maintenance of in-service HV automation switchgear and equipment (primary and secondary). Repairs are currently identified by network operations or inspections where the equipment is performing poorly or out of service. Automation request for repairs are given high priority by maintenance staff as the equipment is valuable for reducing the number of customers affected by a fault, remote monitoring and controlling the HV network (for scheduled switching, fault restoration and load management).

The activity comprises the maintenance of reclosers, load break switches, telemetered ring main units, capacitor banks, voltage regulators, fault indicators (both overhead and underground) and related assets including control boxes, batteries, radios/modems, antennas, software, settings and configuration. Additional technical support is provided for: reliability reporting activities, signal strength investigations (on communications equipment), SIM card management and availability/latency investigations.

4.2.5.2 Reliability driven line patrols

Reliability initiated line patrols represent 26% of forecast distribution reliability operations expenditure. This activity comprises identification and diagnosing reliability problems on the distribution network. Incident prone sections of the network that cause outages to sensitive customers or large numbers of customers are investigated through this activity to identify the root cause of the reliability problems. Information from these line patrols contributes to initiating candidates for the reliability reinforcement and asset replacement portfolios.

This expenditure is forecast as a standalone activity as these targeted patrols provide data that cannot otherwise be obtained from preventive routine types of patrols.

4.3 Customer services and billing

In AA3 we will spend $190 million, 11% of the forecast distribution network operating expenditure, on customer services and billing for distribution-connected customers.

We deliver our customer services and billing activities through four distinct categories:

- *metering* – meter reading and maintain metering assets
- *call centre* – operation of the call centre and associated management services
- *distribution quotations* – desktop based quotations to customers for distribution customer connection applications that do not proceed to capital projects
- *guaranteed service level payments* – comprising payments for supply interruptions exceeding 12 hours and payments for failure to notify customers of planned outages

4.3.1 Metering

In AA3 we will spend $109 million, 7% of forecast distribution network operating expenditure, on metering operating expenditure.

Distribution metering includes meter reading and maintaining metering assets. Western Power's metering activities play an integral role in the Western Australian electricity market, being required to provide customer usage data to market participants. Periodic testing of the population of metering assets is required to ensure they provide data measurement accuracy within defined tolerances and to replace metering assets that are found to exceed these tolerances. Metering services are provided in accordance with Western Power's Metering Management Plan[34].

REGULATORY OBLIGATIONS

Metering functions are required to provide customer usage data to market participants in accordance with:

- *Electricity Industry Metering Code 2005* * which establishes rules for the provision of metering services
- *Code of Conduct for the Supply of Electricity to Small Use Customers 2008* which regulates and controls the conduct of retailers, distributors and electricity marketing agents who supply electricity to residential and small business customers

Part 3 of the Metering Code requires provision and maintenance of a metering asset for each customer in the Western Power Network. This establishes the obligation for us to provide a meter and ensure its metering equipment complies with:

- the Metrology Procedure and the Metering Management Plan approved by the Authority
- the *National Measurement Act*

Part 5 of the Metering Code specifies the metering data measurement and provision requirements that Western Power must satisfy.

Forecast metering operating expenditure is made up of two key activities, meter reading and metering maintenance as shown in Table 26.

Table 26: AA3 distribution metering expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Meter reading	19.0	19.7	20.5	21.2	22.0	102.5
Metering maintenance	1.2	1.2	1.3	1.3	1.4	6.5
Total	**20.2**	**21.0**	**21.8**	**22.6**	**23.4**	**108.9**

4.3.1.1 Meter reading

Meter reading represents 94% of forecast distribution metering operating expenditure. Meter reading and data management covers manual and remote collection of accumulation and interval data for provision to the Western Australian electricity market.

All meters within the Western Power Network are read daily, monthly or bi-monthly. This activity also comprises collection and management of data, data validation, publication and storage of the meter data and ensuring compliance to our metering obligations. Each year we complete approximately:

- 5.6 million bi-monthly manual meter read
- 250,000 monthly manual meter reads
- 30,000 remotely collected daily meter reads

[34] Available at: http://www.erawa.com.au/electricity/library/Approved%20Metering%20Management%20Plan.pdf

Part 5 of the Metering Code specifies the meting data measurement and provision requirements that we must satisfy:

- for each accumulation meter on its network, use reasonable endeavours to undertake a meter reading that provides an actual value at least once in any 12 month period (division 5.4)
- provide validated, and where necessary substituted or estimated, energy data for a metering point to: (a) the user for the metering point; and (b) the IMO (division 5.2)
- validate energy data in accordance with this Code applying, as a minimum, the rules and procedures set out in Appendix 2 (division 5.3)
- meet National Measurement Act 1960[35] obligations that apply

In addition to these statutory obligations, we have metering related contractual obligations with users. These obligations are captured in service level agreements between Western Power and users.

Our AA3 meter reading expenditure will ensure compliance with our obligations under the Metering Code and *Code of Conduct for the Supply of Electricity to Small Use Customers* including and service level agreements with market participants.

STEP CHANGES IN 2011/12

We are increasing spend on metering maintenance activities in 2011/12 by $0.5 million to increase the number of metering verifications and compliance testing at the request of customers anticipated from the Office of Energy's planned changes to the Metering Code, due to be gazetted in December 2011

Clause 5.3 (3) A network operator must, for each metering installation on its network, on and from the time of its connection to the network:

(a) unless otherwise agreed between the network operator and a user, provide, install, operate and, subject to clause 3.5(7), maintain the metering installation in accordance with:

(i) *this Code; and*

(ii) *good electricity industry practice; and*

(iii) *the metrology procedure for the network; and*

(iv) *the service level agreement between the network operator and the user in respect of the metering installation; and*

(b) ensure that the metering installation complies with clause 3.9; and

(c) without limiting clause 3.5(3) (a) ensure that the metering equipment in the metering installation:

(i) *is suitable for the range of operating conditions to which it will be exposed (e.g. temperature, impulse levels); and*

(ii) *operates within the defined limits for that metering equipment as specified in the approved metrology procedure.*

4.3.1.2 Metering maintenance

Metering maintenance represents 6% of forecast distribution metering operating expenditure. Meter maintenance involves activities that we must undertake to ensure the compliance of our meter assets with the Metering Code, Metering Management Plan and *National Measurement Act*. Activities include testing meter population samples or compliance with prescribed measurement accuracy tolerances. The metering measurement and clock accuracy tolerances are set out in section 3.9 and Appendix 1 of the Metering Code.

During AA1, we identified through our meter testing program that a population of approximately 280,000 three phase meters requires replacement in order to comply with the Metering Code. In AA3 we will replace this population of meters and continue our meter

[35] Available at: http://www.austlii.edu.au/au/legis/cth/consol_act/nma1960222/

testing program in accordance with the Metering Management Plan approved by the Authority.

This activity is necessary to ensure we meet the metering obligations as already noted. As such, it addresses the identification of meter accuracy issues and maintains levels of compliances through either meter maintenance or replacement.

REGULATORY OBLIGATIONS

Section 3.5 of the *Metering Code* places the following obligations on us as a network operator:

1. *A network operator must ensure that there is a metering installation at every connection point on its network which is not a Type 7 connection point.*
2. *Unless it is a Type 7 metering installation, a metering installation must:*
    - a) *contain a device which has a visible or otherwise accessible display as detailed in clause 3.2(1); and*
    - b) *have a measurement element for active energy; and*
    - c) *if required by Table 3 in Appendix 1, have a measurement element for reactive energy; and*
    - d) *permit collection of data at the level of accuracy required by clause 3.9.*
3. *A network operator must, for each metering installation on its network, on and from the time of its connection to the network:*
    - a) *unless otherwise agreed between the network operator and a user, provide, install, operate and, subject to clause 3.5(7), maintain the metering installation in accordance with:*
        - i. *this Code; and*
        - ii. *good electricity industry practice; and*
        - iii. *the metrology procedure for the network; and*
        - iv. *the service level agreement between the network operator and the user in respect of the metering installation; and*
    - b) *ensure that the metering installation complies with clause 3.9; and*
    - c) *without limiting clause 3.5 (3) (a) ensure that the metering equipment in the metering installation:*
        - i. *is suitable for the range of operating conditions to which it will be exposed (e.g. temperature, impulse levels); and*
        - ii. *operates within the defined limits for that metering equipment as specified in the approved metrology procedure.*

4.3.2 Call Centre

In AA3 we will undertake $41 million, 2.5% of forecast distribution network operating expenditure, to manage and operate the call centre.

Our call centre functions as a central g*ateway* providing all customer service calls including fault handling, complaints and general enquiry calls. We are required to operate a call centre to comply with our licence conditions and legal obligations. A call centre also provides invaluable business knowledge to ensure the continuing operation of the business including fault communication and forms the central gateway to customer service. The call centre is made up of two key activities as shown in Table 27.

Table 27: AA3 distribution customer services expenditure by activity ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Operation of call centre	6.6	6.9	7.4	7.8	8.2	36.9
Management services	0.8	0.8	0.9	0.9	1.0	4.3
Total call centre	**7.3**	**7.8**	**8.2**	**8.7**	**9.2**	**41.2**

REGULATORY OBLIGATIONS

Under clause 25.1 and 25.2 of Western Power's *Electricity Distribution License EDL 1* * and clause 22.1 and 22.2 of electricity licence:

1. *The Licensee will operate and maintain a trouble call fault management system*
2. *The Licensee must provide prior notification to the Authority if it intends to outsource its trouble call fault management system*.

In addition, clause 13.12 of the *Code of Conduct for the Supply of Electricity to Small Use Customers* requires Western Power as a distributor to keep a record of:

a) *the total number of telephone calls to an call centre operator of the distributor;*
b) *the number of, and percentage of, telephone calls to an operator call centre responded to within 30 seconds;*
c) *the average duration (in seconds) before a call is answered by an operator call centre; and*
d) *the percentage of calls that are unanswered.*

* *Available at: http://www.erawa.com.au/cproot/2437/2/20110114%20Electricity%20Networks%20Corporation%20(t-a%20Western%20Power)%20Electricity%20Distribution%20Licence%201%20(EDL001).pdf*

These two activities are discussed in the following sections.

4.3.2.1 Operation of call centre

Operation of the call centre represents 90% of forecast distribution call centre operating expenditure. The call centre activity ensures we will continue to meet our customer charter requirements and reporting obligations under our licences.

The call centre comprises a combined Contact Centre Solution at Western Power's head office, an after-hours or overflow back-up centre at East Perth and a disaster recovery location at the Forrestfield Depot with all centres operating as a single virtual contact centre, handling fault calls and general enquiries.

4.3.2.2 Management services

Management services for the call centre comprising systems operation and support services are outsourced to BT (Syntegra) and represent 10% of forecast distribution call centre operating expenditure. These management services includes provision of on-site support staff, on-site equipment spares, day to day additions and alterations to the system, maintaining system documentation, support and services.

Continuous operation of the call centre is required to provide customers with information regarding location and expected duration of outages and respond to enquiries and complaints as outlined in the customer charter. In AA3 we are introducing a new customer management strategy for higher levels of service and anticipate increased labour costs will be offset by the introduction of greater self service functionality to customers.

4.3.3 Distribution design and estimation quotations

In AA3 we will spend $23 million, 1.4% of forecast distribution operating expenditure, on distribution design and estimation quotations.

In February 2011, we published the Western Australian Distribution Connections Manual[36] in conjunction with Horizon Power. This manual, available on the Western Power website, is a comprehensive guide to residential and industrial customers as to the applicable roles, responsibilities, processes and minimum technical specifications required to facilitate

[36] Available at: http://www.westernpower.com.au/documents/WA_Distribution_Connections_Manual.pdf

customer connections. As outlined in section 9.2.1 of the manual, we provide a free desktop estimate to customers for distribution customer connection applications.

If the works proceed, this quotation forms part of project costs, otherwise the costs form part of Western Power's operating expenses. Our AA3 forecast distribution design and estimation quotation expenditure is shown in Table 28.

Table 28: AA3 distribution design and estimation quotations expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Distribution design and estimation quotations	4.2	4.3	4.6	4.8	5.0	23.0

4.3.4 Guaranteed service level payments

In AA3 we will spend $17 million, 1.0% of forecast distribution network operating expenditure, on guaranteed service level payments.

Part 3 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (Supply Code) includes mandatory payments to customers for failure to meet certain standards. We are obliged to comply with section 18 *Payment for failure to give required notice of planned interruption* of the Supply Code:

> *If –*
>
> *(a) a corporation fails to give an eligible customer not less than 72 hours notice of a planned interruption as required by section 11(1) (b) (i); and*
>
> *(b) the customer, within 60 days after the interruption, applies to the corporation for compensation under this section,*
>
> *the corporation must, within 30 days after the application is made, pay the sum of $20 in respect of the failure to the customer or as provided by section 22.*

This payment is known as the planned outage payment scheme. On application, we must pay the sum of $20 within 30 days to affected customers. However, we choose to pay customers $50 for this payment as part of our strategy for holding Western Power to account for this measure.

In addition, we are obliged to comply with section *19. Payment for supply interruptions exceeding 12 hours* of the Supply Code:

> *(1) If –*
>
> *(a) the supply of electricity by a corporation to a customer is interrupted for more than 12 hours continuously, whether or not notice has been given to the customer under section 11(1); and*
>
> *(b) the customer, within 60 days after the interruption ceases, applies to the corporation for compensation under this section,*
>
> *the corporation must, within 30 days after the application is made, pay the sum of $80 in respect of the interruption to the customer or as provided by section 22.*

This payment is known as the extended outage payment scheme. On application, we must pay the sum of $80 within 30 days to affected customers.

Under Access Code section 11.1 and *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* section 9, we are obliged to meet certain minimum service levels and certain standards of supply. Carrying out this activity will mitigate the risk faced by the business in complying with these requirements.

AA3 forecast guaranteed service level payments operating expenditure is shown in Table 29.

Table 29: AA3 distribution guaranteed service level payments expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Distribution guaranteed service level payments	2.5	3.0	3.4	3.9	4.4	17.3

4.4 Non-recurring operating expenditure

In AA3 we will spend $50 million, 3.0% of forecast distribution network operating expenditure, on distribution non-recurring operating expenditure.

We have forecast specific non-recurring distribution operating expenditure activities. These activities tend to be one-off, project based or for a discrete time period and are therefore excluded from the roll-forward approach to forecasting operating expenditure as described in chapter 7 of the AAI.

AA3 distribution non-recurring operating expenditure comprises:

- *field survey data capture project* – we commenced a program in AA2 to conduct a physical field audit of assets to ensure data accuracy and thereby improve asset management and investment planning with pilot programs in Picton and Northam. In AA3 Western Power will complete this program across its entire network
- *network control services* – payments for generation or demand side management in constrained sections of the network to enable us to efficiently defer major capital investments

The activities forecast for AA3 are both aimed at efficiently lowering network investment and asset management costs over time, consistent with section 6.52(a) and 6.40 of the Access Code. A breakdown of AA3 forecast distribution non-recurring operating expenditure by activity is shown in Table 30.

Table 30: AA3 distribution non-recurring operating expenditure by activity ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Field survey data capture project	5.7	7.6	7.7	7.8	8.1	37.0
Network control services	2.3	2.4	2.5	2.6	2.7	12.6
Total non-recurring	**8.0**	**10.0**	**10.2**	**10.4**	**10.9**	**49.5**

These projects are discussed in the following sections.

4.4.1.1 Field survey data capture project

The field survey data capture project represents 75% of forecast distribution non-recurring expenditure. In AA3 we will invest $37 million to complete a field survey data capture program across the entire Western Power Network to achieve the following:

- address Energy*Safety's* finding to verify asset records against field installations, from the *2008 Distribution Wood Pole Audit Review*
- accurately capture data on pole stays, supporting the wood pole inspection programme and enabling the efficient, and more accurate, calculation of wood pole serviceability
- correct network connectivity data, leading to optimised network planning and improved confidence in load flow analysis
- improve customer connectivity data, accurately connecting customers to the network
- record missing assets, ensuring they are included in inspection and maintenance programs
- improve the spatial accuracy of data on above ground assets, leading to improvements in the effectiveness of mobile field work and more accurate Dial Before You Dig plans

REGULATORY OBLIGATIONS

The field survey data capture program is required to comply with elements of the *Energy Safety order 01-2009.* Specifically the Wood Pole Management Plan must:

- action 4.2(h) – identify the wood pole asset records data used in developing the plan
- action 4.2(i) – detail the process used to ensure the data are accurate and sufficient to ensure the plan will deliver the wood pole safety outcomes required.

The Rural Pole Safety Improvement Plan must:

- action 6.1(a) (i) – identify and record: The number and location of rural distribution poles; that is all poles not within a town or city boundary

The field survey data capture project will provide critical input to Western Power's pole management activities in accordance with the order. It will provide robust data on actual pole numbers and locations which will improve the efficacy of our pole manage planning and execution.

We require significantly more data to support evolving business needs and to comply with current regulatory obligations. The quality of network asset data has a direct bearing on the effectiveness and efficiency of the investment decisions, the asset management strategies employed and the total asset lifecycle costs. Data quality issues in Western Power have become a major constraint to implementing leading asset management practices, with the majority of these issues relating to incomplete data. The magnitude is significant, particularly in country areas where more than 40% of critical data is missing on primary equipment such as distribution transformers. A field audit conducted over three feeders in 2005 found approximately 2% of poles and related assets missing from the asset information systems. Scaling this across the network indicates a likely 15,000 unrecorded poles.

Our ability to improve data quality is inhibited by an absence of a field audit capability. A large proportion of data quality issues, such as incomplete data and missing assets, cannot be addressed by current desktop data cleansing programmes.

The purpose of the Field survey data capture project is to address legacy data quality issues. We will build upon the two AA2 pilot field data surveys by undertaking a large-scale data capture program across the entire Western Power Network during AA3. Programs to address wide-spread data quality issues are common practice by our network peers in Australia.

Other distribution businesses who have undertaken a large-scale data capture project include:

- United Energy (Vic)
- SP AusNet (Vic)
- Powercor (Vic)
- ETSA Utilities (SA)
- Energy Australia (NSW)
- Energex (Qld)

We incurred lower than anticipated field survey data capture costs in AA2 as initial pilot programs were limited to two locations and some 66,000 poles and related assets. This was to gain better information to design the data capture program for the rest of the network as well as gather market tested pricing upon which to base estimates for completing the remainder of the project during AA3. The AA3 forecast has been determined on the basis of the continuation of unit costs incurred in the AA2 stages of the project.

4.4.1.2 Network control services

Network control services represent 25% of forecast distribution non-recurring expenditure. Please see discussion of these services in section 3.3.1.1. The areas targeted for network control services on the distribution network in AA3 include Ravensthorpe and Bremer Bay. The least cost option to alleviate network constraints in these areas is provided by daily peak lopping to a small islanded network supplied via power stations at each town.

5 Corporate operating expenditure

Corporate operating expenditure covers the corporate services and corporate wide expenses necessary to support and sustain the operational divisions of Western Power, such that we can ensure the continuous provision of covered services for customers.

In AA3 we will spend $584 million on forecast corporate operating expenditure.

As set out in chapter 7 of the AAI, our corporate operating expenditure is segregated into two high level categories: business support divisional costs and corporate-wide expenditure. The detailed and high level categories of forecast expenditure are shown in Table 31.

Table 31: Corporate forecast operating expenditure in AA3 ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% total
Business support divisional costs	72.1	72.2	75.4	80.5	83.3	383.5	65.7%
Insurance	25.9	26.8	27.4	28.3	29.1	137.4	23.5%
Rates and taxes	6.6	7.1	7.9	8.8	9.5	39.9	6.8%
Energy*Safety* levy	4.3	4.5	4.6	4.8	4.9	23.2	4.0%
Corporate wide expenditure	36.9	38.4	40.0	41.9	43.5	200.6	34.3%
Total corporate operating expenditure	108.9	110.6	115.4	122.4	126.7	584.1	100.0%

Overall increases in insurance, business support divisional costs and rates and taxes are the main drivers of increases in our business support operating expenditure over AA3.

We have made some changes to the categorisation of costs within the corporate (business support) category such as:

- creating a new corporate services division – this occurred as part of Western Power's 2010/11 organisational restructure which (among other things) brought together the key support areas of the organisation to achieve accountability and a clear cost and service focus
- removing guaranteed service level payments and distribution design and estimating costs which existed within business support operating expenditure prior to 2012/13 but have been placed in their own regulatory category for AA3 as they are not considered a corporate (business support) expense

5.1.1 Corporate wide expenditure

In AA3 we will spend $201 million, 34% of forecast corporate business support operating expenditure, on corporate wide expenditure.

It comprises costs associated with insurance, rates and taxes, the Energy*Safety* levy. We have very little scope to influence the overall costs associated with most of these categories of expenditure as they are externally driven.

Forecasts for corporate wide expenditure items have been developed on the following basis:

- insurance – our insurance forecasts are based on the analysis and aggregation of individual forecasts for insurance cost items in AA3. This includes self insured losses and our costs for purchasing insurance for public liability, fire and perils/property, contract works and workers compensation. Our insurance forecasts include broker fees. Our individual insurance forecasts include:

- self insured losses – forecasts for bushfire losses remain flat and non-bushfire losses include 5% per annum increase (based on historical claims activity)
- public liability insurance – ongoing bushfire losses are expected to have a significant impact on our premiums – our forecasts incorporate an annual increase of 11.5% (based on broker's guidance and an expectation of low to moderate losses)
- fire and perils/property – based on our historical claims activity and organic growth in the value of network assets, our forecasts incorporate a 5% per annum increase
- contract works – covers the testing and commissioning of works performed by Western Power, the Alliances and authorised third party contractors – our forecasts remain flat over AA3
- workers compensation costs – our forecasts incorporate bi-annual increases of 5% for wages and 5% for premiums
- broker fees – we have the right to extend our current service agreement which is due to expire 1 January 2012 for a further two years. The forecast cost of our annual broker fee includes a one-off increase of 10% over the AA3 period, but remains generally flat otherwise
- rates and taxes – land tax forecasts were based on our current spend with adjustments to reflect planned acquisitions and disposals and an increase in land values. For land tax forecasts beyond 2012/13, the Valuer General's Office advised that increases of 8% -10% per annum are advisable for budgeting purposes. Based on this advice and assumed future acquisitions, a 10% increase has been used. Our local government rate equivalence tax forecasts are based on a combination of advice received from Valuer General's Office, historical trends and future land acquisitions. Our FESA levy forecasts are based on a continuation of historical trends
- Energy*Safety* levy – the Energy*Safety* levy that we pay to the Office of Energy reflects the percentage of our customer connections relative to total industry connections. Our AA3 Energy*Safety* levy forecasts assume that the percentage of customer connections will remain constant relative to total industry connections and that the Office of Energy's costs are predominantly labour driven and so will escalate accordingly

5.1.2 Business support divisional

In AA3 we will spend $383 million, or 66% of forecast corporate operating expenditure, on business support divisional costs.

Our business support divisional costs represent the costs of operating the various divisions within Western Power, which are required to support and sustain the ongoing operation of the network. They comprise:

- Corporate Services – responsible for IT, HR, safety and health, corporate real estate and corporate communication functions
- Strategy and Finance – provides business planning and analysis, corporate accounting and taxation and treasury functions to plan, manage and measure Western Power's financial operation and performance

- Regulation and Sustainability – supports the delivery of Western Power's access arrangement, provides expertise to meet Western Power's ongoing regulatory interactions and oversees planning and development for the creation of a more sustainable network
- Legal and Governance – responsible for providing advice and support to Western Power's board of directors, senior management and other business areas on issues involving compliance and risk management, internal audit, ERA license audits, governance, public interest disclosure and legal matters
- Enterprise Solutions Partners – focuses on key organisation-wide strategic initiatives and longer term business transformation that is central to Western Power's delivery of ongoing improvements in efficiency, productivity and sustainable cost reductions
- CEO – includes Western Power's CEO expense, the costs of CEO-related functions and Corporate Affairs.

These costs are predominantly labour driven. As a result, the forecasts have been developed assuming the continuation of current staffing requirements with some small adjustments for known changes (such as increased staffing to support a higher level of recruitment and increased business planning).

The increase in our business support divisional costs over the AA3 period is primarily driven by forecast increases in the market price of labour.

6 Transmission capital investment

Transmission capital expenditure comprises work for expanding the capacity of the Western Power Network and replacing and reinforcing where necessary the existing assets.

In AA3 we will invest $1.927 billion on transmission capital projects and programs necessary to connect new customers and ensure the continuous provision of covered services for existing customers on the Western Power Network. Of this, $214 million is forecast to be contributed by individual customers.

As set out in chapter 8 of the AAI our transmission capital expenditure is segregated into the following high level categories: growth, asset replacement and renewal, improvement in service and compliance. The detailed and high level categories of expenditure are shown in Table 32.

Table 32: AA3 forecast transmission network capital expenditure ($ million real at 30 June 2012)

AA3 expenditure by category	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of total (gross)
Capacity Expansion	217.3	132.3	215.7	364.3	247.7	1,177.3	61.1%
Customer Driven	73.4	74.0	75.2	76.3	79.0	377.9	19.6%
Growth (gross)	290.6	206.3	290.9	440.7	326.8	1,555.3	80.7%
Less contributions	41.4	41.8	42.5	43.1	44.7	213.6	11.1%
Growth (net)	249.2	164.5	248.4	397.5	282.1	1,341.7	69.6%
Asset replacement and Renewal	30.8	33.9	34.8	35.4	37.8	172.6	9.0%
Compliance	14.3	17.3	24.8	31.5	32.8	120.7	6.3%
SCADA and communications (Improvement in Service)	14.4	12.2	13.5	19.3	19.4	78.8	4.1%
Transmission total (gross)	350.2	269.7	363.9	526.9	416.7	1,927.3	100.0%
Transmission capital expenditure to be recovered from reference tariffs	**308.7**	**227.9**	**321.4**	**483.7**	**372.0**	**1,713.7**	**88.9%**

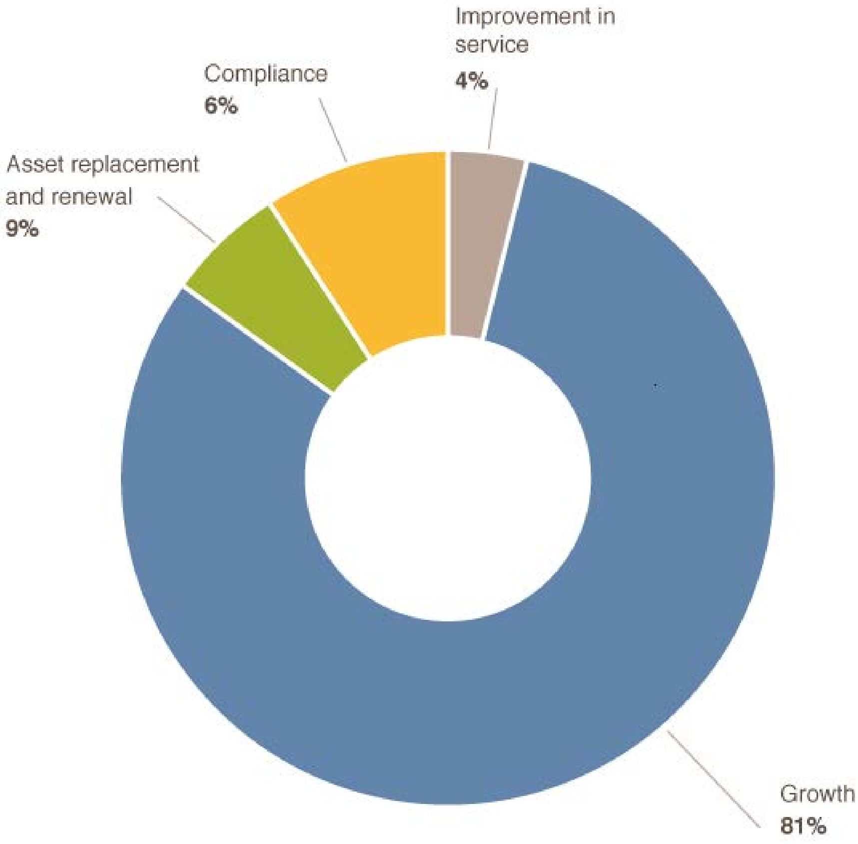

Figure 26: AA3 transmission capital expenditure by reason

6.1 Growth

In AA3 we will invest $1.555 billion, 81% of forecast transmission network capital expenditure, expanding and improving security of supply on the transmission network.

We deliver our growth projects and programs through two distinct categories:

- *capacity expansion* – upgrading existing infrastructure and installing new/additional infrastructure to meet load growth and restore system security as per the requirements of the *Technical Rules* including planning criteria
- *customer driven* – providing the connection between transmission customers' premises and the network relocating our assets at the customers' request

REGULATORY OBLIGATIONS

We must plan the transmission network so that there is sufficient capacity to transmit power from power stations to load centres then to individual customers, and that the requirements in the *Technical Rules* and *Wholesale Electricity Market Rules* are met.

Section 12.4 of the Access Code states that:

> *Subject to any exemptions granted under sections 12.34 and 12.41, the service provider and users of a network must comply with the technical rules.*

Appendix 6 (A6.1(m)) of the Access Code sets out the matters that must be addressed by the *Technical Rules*. These matters include the criteria for planning the network, which must include:

i. Contingency criteria

ii. Steady state criteria, including:

   A. frequency limits
   B. voltage limits
   C. thermal rating criteria
   D. fault rating criteria
   E. maximum protection clearing times
   F. auto reclosing policy
   G. insulation coordination standard

iii. Stability criteria, including:

   A. rotor angle stability criteria
   B. frequency stability criteria
   C. voltage stability criteria

iv. Quality of supply criteria, including:

   A. voltage fluctuation criteria
   B. harmonic voltage criteria
   C. harmonic current criteria
   D. voltage unbalance criteria
   E. electro-magnetic interference criteria

v. Construction standards criteria.

Importantly, unlike other Australian transmission utilities, the *Wholesale Electricity Market Rules* under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* require that we plan our network on an unconstrained basis. This means the network is planned to ensure that for contingencies within the planning criteria in the *Technical Rules*, all generators are able to export up to their declared sent out capacity, regardless of what other generators are exporting. This requires more investment in the network than if it was planned on a constrained basis.

6.1.1 Capacity expansion

In AA3 we will invest $1.177 billion, 61% of forecast transmission network capital expenditure, to expand capacity in the transmission system.

Capacity expansion works maintain supply and expand the existing Western Power Network to meet the growing demand for energy through increasing the capacity of transmission lines and substations. This ensures our ongoing ability to support the growth of existing residential and business loads, whilst ensuring that we are maximising compliance with the Technical Rules.

Capacity expansion works typically involve a relatively small number of projects, or programs, that are highly variable in cost. This makes forecasting or comparing to historical expenditure difficult due to the lumpy investment which results in step changes in available capacity that may be drawn down over longer periods of time. Large one off projects can impact on the profile of investment over time as demonstrated in Figure 27 which shows the Mid West Project separately.

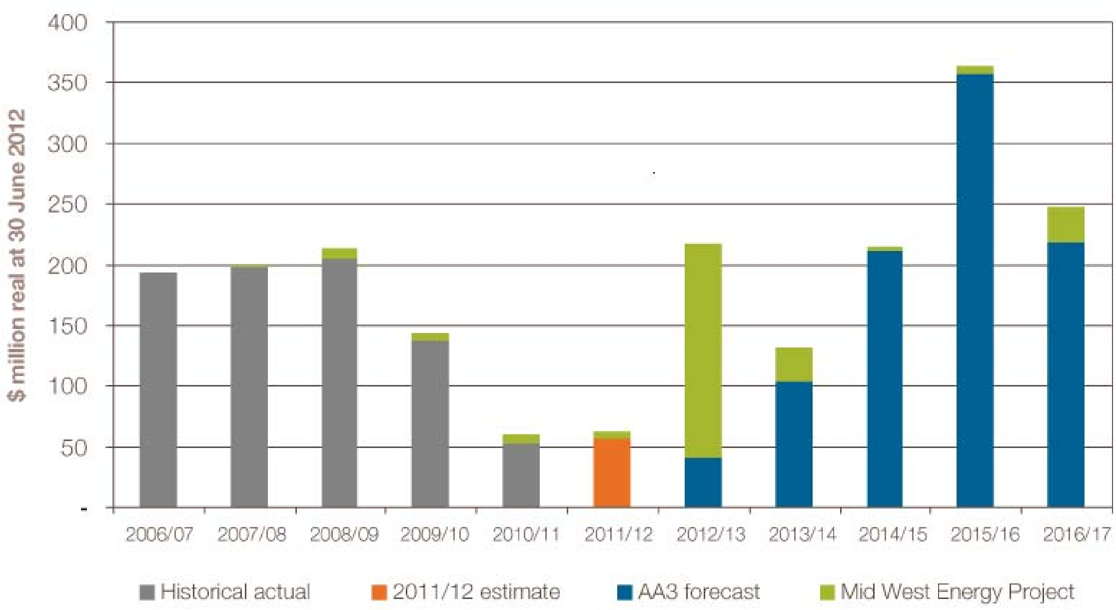

Figure 27: Transmission capacity expansion historical and forecast capital expenditure

New facilities investment test

New facilities investments in transmission capacity expansion are only undertaken where either section 6.52(b) (ii) or section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (ii) of the Access Code requires that 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*. Major augmentations that can facilitate connection of cheaper generation, for example, the Mid West Energy Project Stage 1 (Southern section) satisfy the net benefits test.

Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services.* With the exception of the Mid West Energy Project Stage 1 (southern section) which meets section 6.52(b) (ii) under the Access Code, AA3 transmission capacity expansion expenditure has been assessed as meeting section 6.52(b) (iii). The transmission network development plan indicates the extent to which contracted covered services cannot be provided if not for the investment. The plan has been developed in accordance with the planning criteria and other obligations under the *Technical Rules*.

AA3 transmission capacity expansion expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI.

REGULATORY TEST

Under section 9.2 of the Access Code; *A service provider must not commit to a major augmentation before the Authority determines, or is deemed to determine, under section 9.13 or 9.18, as applicable, that the test in section 9.14 or 9.20, as applicable, is satisfied.*

Section 9.20 of the Access Code states:

The test in this section 9.20 is satisfied if the Authority is satisfied that:

(a) the service provider's statement under section 9.16(b) is defensible; and

(b) the service provider has applied the regulatory test properly to each proposed major augmentation:

(i) using reasonable market development scenarios which incorporate varying levels of demand growth at relevant places; and

(ii) using reasonable timings, and testing alternative timings, for project commissioning dates and construction timetables for the major augmentation and for alternative options;

and

(c) the consultation process conducted by the service provider meets the criteria in section 9.16(c).

The regulatory test is an assessment of whether a proposed major augmentation to a covered network maximises the net benefit to those who generate, transmit and consume electricity after considering alternative options, including non-network options (e.g. contracted demand management and generation support). Section 9.16 of the Access Code requires that:

A major augmentation proposal submitted under section 9.15

(a) must describe in detail each major augmentation to which the major augmentation proposal relates; and

(b) must state that, in the service provider's view, each proposed major augmentation maximises the net benefit after considering alternative options;

and

(c) must demonstrate that the service provider has conducted a consultation process in respect of each proposed major augmentation which:

(i) included public consultation under Appendix 7; and

(ii) gave all interested persons a reasonable opportunity to state their views and to propose alternative options to the proposed major augmentations, and that the service provider had regard to those views and alternative options; and

(iii) involved the service provider giving reasonable consideration to any information obtained under sections 9.16(c)(i) and 9.16(c)(ii) when forming its view under section 9.16(b);

and

(d) must comply with the current requirements published under section 9.17.

(e) may include a request that the Authority give prior approval under section 6.72 in respect of the new facilities investment for one or more proposed major augmentations.

A major augmentation is defined as a new facilities investment for assets which exceeds $32.7 million (CPI adjusted for 2010/11) where the network assets comprising the augmentation are, or are to be, part of the transmission system.

In AA2, the Authority was satisfied that the Mid West Energy Project Stage 1 (Southern section) met the Regulatory Test. In AA3 we will ensure that the Authority is satisfied that the regulatory test is met before proceeding with any other major augmentation that exceeds the threshold stated above.

The specific projects that make up capacity expansion expenditure are identified through the network development planning process, which is discussed in section 2.2. A breakdown of AA3 forecast transmission capacity expansion expenditure by activity (grouping of projects) is shown in Table 33 and Figure 28.

Table 33: Transmission capacity expansion expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Mid West Energy Project	175.8	28.4	3.9	6.2	29.6	243.8
Supply constraints	20.9	78.4	108.6	117.8	59.3	385.0
Thermal constraints	0.4	8.0	70.7	193.5	146.1	418.7
Voltage regulation	2.9	5.7	21.6	37.6	2.4	70.2
Environmental	9.6	5.4	4.9	4.5	4.1	28.5
Planning costs	7.7	6.5	5.6	4.7	6.2	30.8
Fault levels	-	-	0.4	-	-	0.4
Capacity expansion total	**217.3**	**132.3**	**215.7**	**364.3**	**247.7**	**1,177.3**

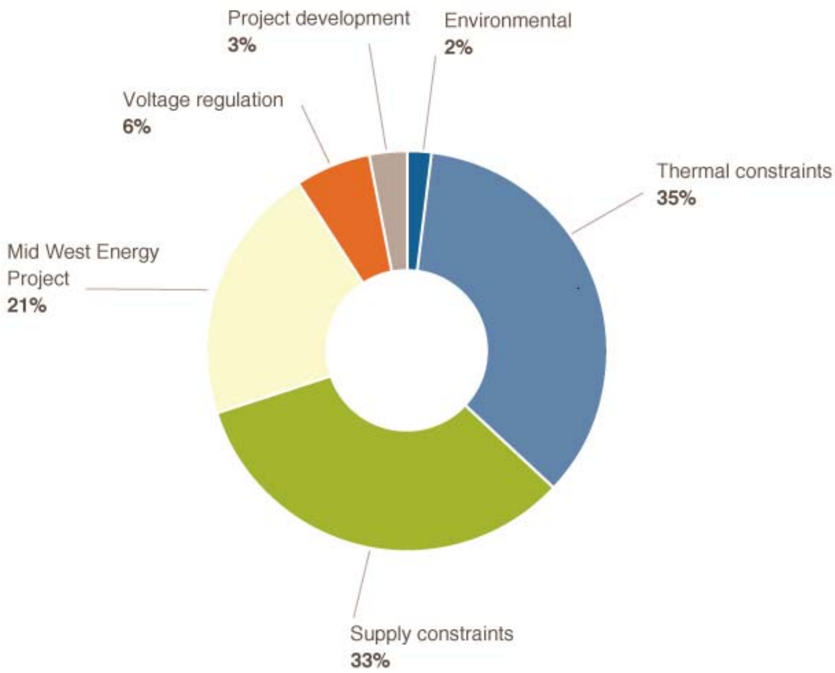

Figure 28: AA3 transmission capacity expansion expenditure by activity

Each of these activities is discussed in the following sections.

6.1.1.1 Mid West Energy Project

In AA3 we will invest $244 million, 21% of forecast transmission capacity expansion expenditure, on the Mid West Energy Project. The Mid West Energy Project will increase the power transmission capacity in the country north planning area to:

- meet the forecast increased peak electricity demand in the region
- meet the forecast increase in electricity generation capacity in the region

- facilitate the connection of major customers (load and generation) to the network

Existing supply capacity and constraints

The network in the country north region is a long 132 kV network extending approximately 400 km from the northern outskirts of Perth to north of Geraldton. The length of the transmission lines in this network and the purposes for which it was initially designed mean that it is electrically weak and has limited capacity to supply additional load. The network characteristics and their relationship with the rest of the interconnected system mean that capacity to connect generators and new block loads to this network is also limited.

A number of resource project proposals exist within the region. There has been an upsurge in mining activity with multiple iron ore projects planning to export ore through Geraldton. These have the potential to make the region a major participant in the overall state mining sector. Each of these proposals will involve substantial power supply requirements which would bring forward the need to reinforce the existing network. The loads associated with these resource projects are an order of magnitude higher than the existing regional demand and will have a fundamental impact on the network requirements for the region.

Furthermore, the region is recognised as being a prospective major contributor to renewable generation in Western Australia with numerous plans for wind farms in the region. At present there are constraints within the network (as well as within the broader electricity system) that limit the ability of new wind farms to connect in this region, as shown in Figure 29.

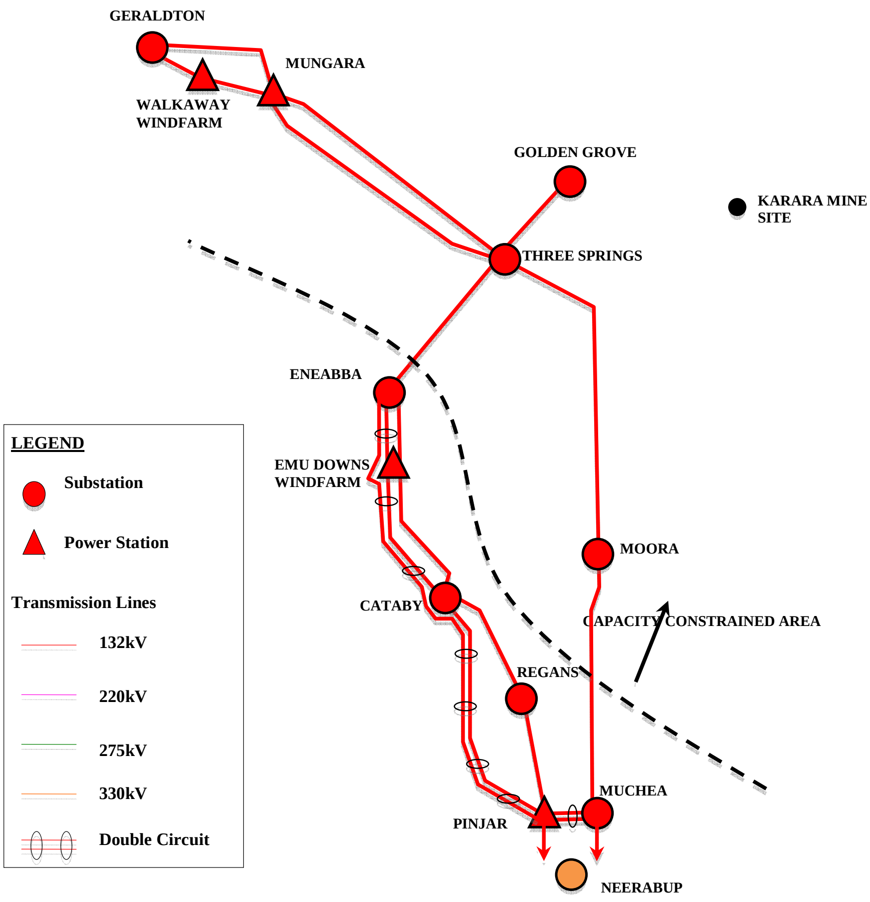

Figure 29: Existing network layout showing area where capacity is constrained

As load continues to grow in the future, in addition to supply constraints, there will be thermal constraints on the transmission lines connecting Geraldton and voltage stability issues.

Addressing the supply constraints

Western Power identified and evaluated a number of options to increase the power transmission capacity in the Mid West region. The options assessed include network reinforcement, local generation and demand side management solutions, as outlined in the *Major Augmentation Proposal, Regulatory Test Submission, Mid West Energy Project – Southern Section, Neerabup to Karrara Mine Site via Eneabba.*[37]

The recommended option entails constructing a new 330 kV double circuit transmission line between Pinjar and the future Eneabba terminal site, an existing Neerabup-Pinjar 330 kV line conversion, a new 330/132 kV terminal at Three Springs and a new double circuit 330 kV line between Eneabba and Three Springs. The new line will follow an existing easement between Pinjar and Eneabba and will initially operate with one circuit at 330 kV and the other at 132 kV (effectively replacing the decommissioned 132 kV line) until such time as there is sufficient electricity demand or new generator connections to warrant the conversion of the second circuit to 330 kV.

To connect to the new infrastructure, Karara Mining Limited are building a new double circuit 330 kV line between Three Springs and Koolanooka and then a single circuit 330 kV line to the Karara mine site. This section of line will be constructed by Karrara Mining Limited. Western Power is negotiating agreements that will allow the line to be used in the same way as other parts of the Western Power Network for future connection and access by third parties.

A 330 kV/132 kV transformer will be installed at Three Springs to interconnect the existing 132 kV network to future connections and access by third parties. This transformer interconnection will be initially constructed by Karara to provide start-up supply to its mine, but once the 330 kV transmission line from Neerabup is connected, it will be reconfigured to provide increased capacity to Geraldton to meet the underlying load growth needs of the area.

During the second half of 2010, we completed consultation on the proposed Mid West Energy Project Stage 1 (Southern section) and lodged a regulatory test submission with the Authority for approval. In February 2011 the Authority determined that the project satisfied the Regulatory Test[38]. On 3 August 2011, we submitted a new facilities investment test application to the Authority for approval[39]. The Authority is yet to publish a decision on this submission.

6.1.1.2 Supply constraints

In AA3 we will invest $385 million, 33% of forecast transmission capacity expansion expenditure, on projects to address other supply constraints identified in section 2.2.3.1. We will construct new zone substations, a new 132 kV double circuit line and install new transformers at existing substations to address supply constraints where load forecast is expected to exceed capacity. The specific projects that will be undertaken during AA3 to address emerging supply constraints set out in Table 34.

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[37] Available at: http://www.erawa.com.au/3/954/48/mid_west_energy_project_southern_section_augmentat.pmEconomic

[38] See 'Final Determination on the Regulatory Test for the Mid West Energy Project (Southern Section), 3 February 2011. Available at: http://www.erawa.com.au/cproot/9315/2/20110203%20Final%20Determination%20on%20the%20Regulatory%20Test%20for%20the%20MW%20Energy%20Project%20(SS)%20-%20Submitted%20by%20WP.pdf

[39] Available at: http://www.erawa.com.au/3/1178/48/mid_west_energy_project_southern_section_augmentat.pm

Table 34: AA3 projects to address supply constraints

Region	Project	AA3 expenditure ($ million real at 30 June 2012)
Metro CBD	New zone substation in the CBD	102.1
	New 80 MVA Transformer at Cook Street	13.9
Metro North	Complete new zone substation at Balcatta	5.2
	New zone substations in the Osborne Park and Shenton Park areas and at Wanneroo East	66.4
	New 5 km 132 kV double circuit line from Neerabup Terminal to new Wanneroo East zone substation	3.1
	New 33 MVA transformers at Clarkson, Henley Brook, Joondalup, Wangara and Yanchep	25.3
Metro South	New zone substations in the Waikiki, East Rockingham and Mandurah/Meadow Springs areas	57.5
	New 33 MVA transformers at Mason Road, Meadow Springs, Willetton, Armadale, Belmont area, Southern River and Marriot Rd	37.6
Metro East	New 33 MVA transformers at Midland Junction and Hazelmere	12.1
Country North	New 33 MVA transformer at Three Springs	6.2
Country South	New zone substations in the Busselton and Dalyellup areas	37.7
	New 33 MVA transformers at Albany and Capel (2)	17.9

6.1.1.3 Thermal constraints

In AA3 we will invest $419 million, 36% of forecast transmission capacity expansion expenditure, to address thermal constraints in the network identified in section 2.2. We will construct new 132 kV circuits, convert existing single circuits to double circuits, update existing 132 kV circuits to 330 kV and implement intertripping protection schemes to address emerging thermal constraints as set out in Table 35.

Table 35: AA3 projects to address thermal constraints

Region	Projects	AA3 expenditure ($ million real at 30 June 2012)
Metro CBD	132 kV double circuit cable works from East Perth to a new CBD zone substation	31.9
Metro	New 132 kV circuit from South Fremantle to Western Terminal	51.5
	South Metro reconfiguration	43.5
Country North	New single circuit 132 kV line from Mungarra to Geraldton	43.0
	New 330 kV Eneabba Terminal	18.2
Country South	Replace existing wood pole 132 kV circuits from Muja to Kojonup with a double circuit steel pole 132 kV line	89.2
	Second 132 kV line from Kojonup to Albany	78.4
	New 330 kV Pinjarra Terminal	47.9
Various	Includes: Various smaller line works projects Intertripping protection works (special protection schemes)	15.1

6.1.1.4 Voltage regulation

In AA3 we will invest $70 million, 6% of forecast transmission capacity expansion expenditure, on a static var compensator and capacitor banks to improve voltage regulation.

The specific projects that will be undertaken during AA3 to improve voltage regulation are set out in Table 36.

Table 36: AA3 projects to improve voltage regulation

Region	Projects	AA3 expenditure ($ million real at 30 June 2012)
Metro CBD	New 330 kV static var compensator at Northern Terminal (2 x 100 MVAr blocks, +250/-120 MVAr dynamic)	53.6
Other	New capacitor banks at: 120 MVAr at Cannington Terminal, Southern Terminal and in the CBD area 90 MVAr at Guildford Terminal and WT 40 MVAr at Busselton 10 MVAr at Marriott Road and Chapman	16.6

6.1.1.5 Planning costs

In AA3 we will invest $31 million, 3% of forecast transmission capacity expansion expenditure, to plan and develop project proposals. We may only add capacity expansion investment to the capital base if it satisfies the new facilities investment test and may only proceed with major augmentations if they satisfy the regulatory test.

To be able to demonstrate that all projects meet the relevant tests, we are required to identify and assess a range of options as discussed in chapter 4 of the AAI.

6.1.1.6 Environmental costs

In AA3 we will invest $28 million, 2% of forecast transmission capacity expansion expenditure, on the statutory development and environmental approvals required for transmission capacity expansion projects. These approvals are necessary under State and Commonwealth legislation to allow capital projects to proceed.

This expenditure also includes compensation payable for easements for transmission line assets over 200 kV. Western Power is compelled to acquire an easement under the requirements of the *Energy Operators (Powers) Act 1979*[40] In some circumstances an easement may also be registered for a 132 kV transmission line if it is determined that the impact of the line to freehold land is similar to a transmission line over 200 kV.

Before we undertake any activities associated with the construction of infrastructure that has the potential to impact the environment, an environmental impact assessment (EIA) must be completed and environmental approval obtained from the relevant authorities. To obtain approval, we must be able to demonstrate that a comprehensive options analysis of the infrastructure proposal was undertaken and that the most suitable option has been selected, identify potential environmental impacts of the proposal and propose methods of environmental management which will mitigate impacts to the extent practicable.

The EIA information allows the relevant government regulatory authorities to assess the likely impacts on the environment. If the impacts are likely to be significant then a decision is made as to whether the proposal should be allowed to proceed and, if so, under what conditions to ensure the environment is protected.

EIAs are regulated under the *Environmental Protection Act 1986* (EP Act) and the *Commonwealth Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act)*[41]. There are three main environmental approvals that Western Power can be required to obtain before the commencement of a project. Figure 30 provides a simplified overview of Western Power's Environmental Approvals process.

[40] Available at: http://www.austlii.edu.au/au/legis/wa/consol_act/eoa1979297/
[41] Available at: http://www.environment.gov.au/epbc/

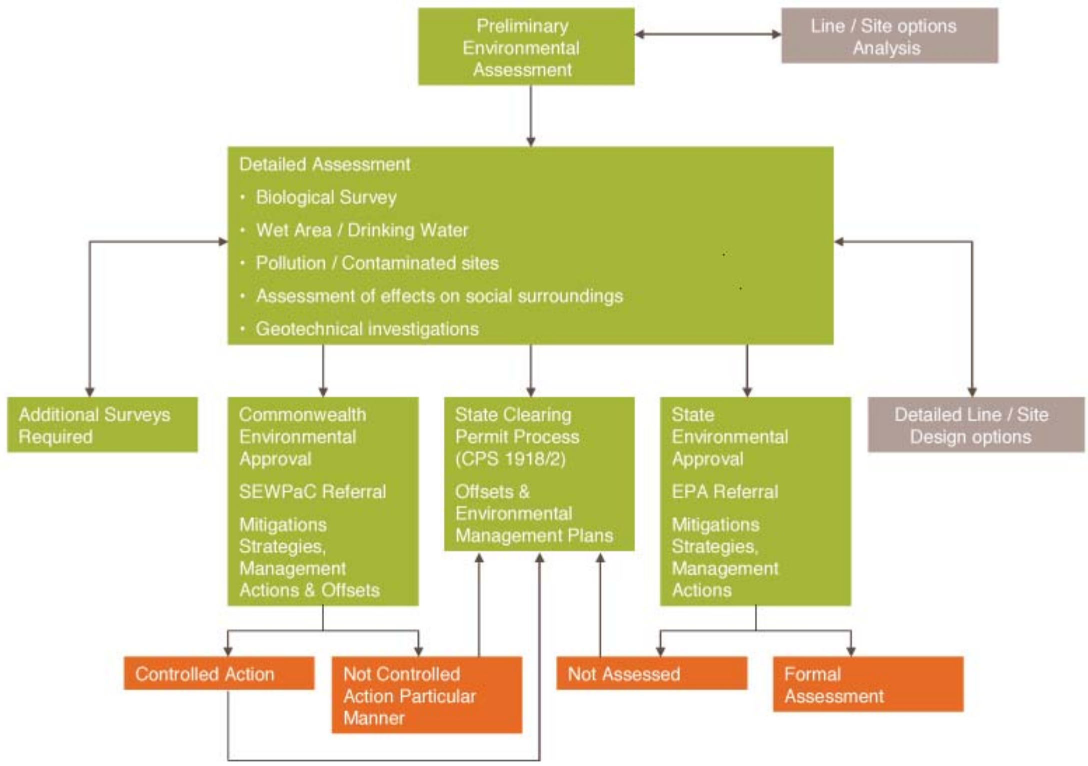

Figure 30: Western Power's environmental approvals process

Proposals with the potential to significantly impact the environment must be referred to the Environmental Protection Authority (EPA) under Part IV of the EP Act (Environmental Impact Assessment). The EPA then makes a decision on the level of assessment of a proposal and sets conditions or provides guidance on environmental management.

The EPBC Act requires a proposal to be referred to the Department of Sustainability, Environment, Water, Population and Communities (SEWPaC) if it is likely to have a significant impact on 'Matters of National Significance' as defined by the EPBC Act. The Minister may attach conditions to the approval to protect, repair or mitigate damage to a matter of national significance under the EPBC Act.

We are increasingly aiming to obtain environmental approvals and other statutory (non-environmental) approvals as early as possible in the life of a project, and for a number of potential project options. This ensures that there are a number of flexible options available when future network reinforcements are required.

It also enables a good understanding of environmental considerations to be taken into account for each of the potential options, prior to any decisions being made. The assessment of strategic proposals process is designed to link with other necessary environmental approvals at the state and federal level.

6.1.1.7 Fault levels

In AA3 we will invest $0.4 million of forecast transmission capacity expansion expenditure, on work required to reduce fault levels within system plant and equipment ratings. These works include all components required either comply with the future fault levels on the network, including plant and equipment up-rating.

6.1.2 Customer driven

In AA3 we will invest $378 million, 20% of forecast transmission network capital expenditure, on works driven by our transmission customers. Of this expenditure, connecting customers will contribute $214 million or 57%.

Transmission customer driven expenditure caters for the need to expand or reinforce the network to enable physical connection of individual, known generators or major transmission block loads, or to relocate transmission assets at a customer's request. This category of expenditure comprises a range of discrete projects. Specific projects are identified through applications for connection made by customers, processed in accordance with the *Applications and Queuing Policy*.

Customer driven transmission works are highly volatile in expenditure and timing as they are subject to changes in customer needs. Following the global financial crisis, we saw a drop in the number of new connection applications. However, in 2010/11 and 2011/12 this has returned to and surpassed historical numbers of applications as shown in Figure 31.

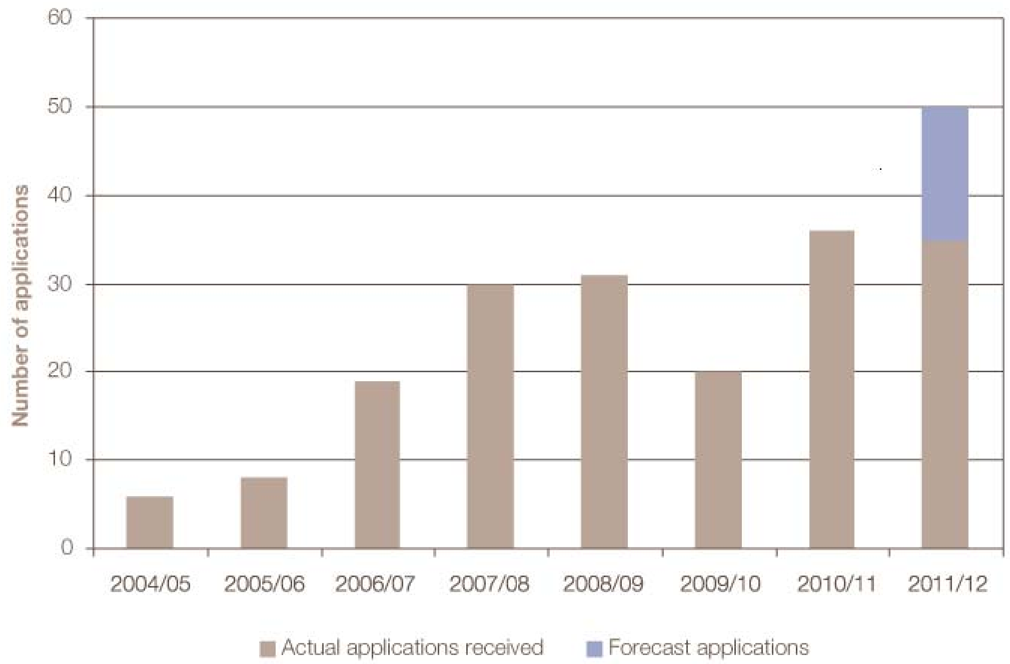

Figure 31: Number of transmission customer applications

Figure 32 shows the transmission customer driven expenditure from AA1 to AA3.

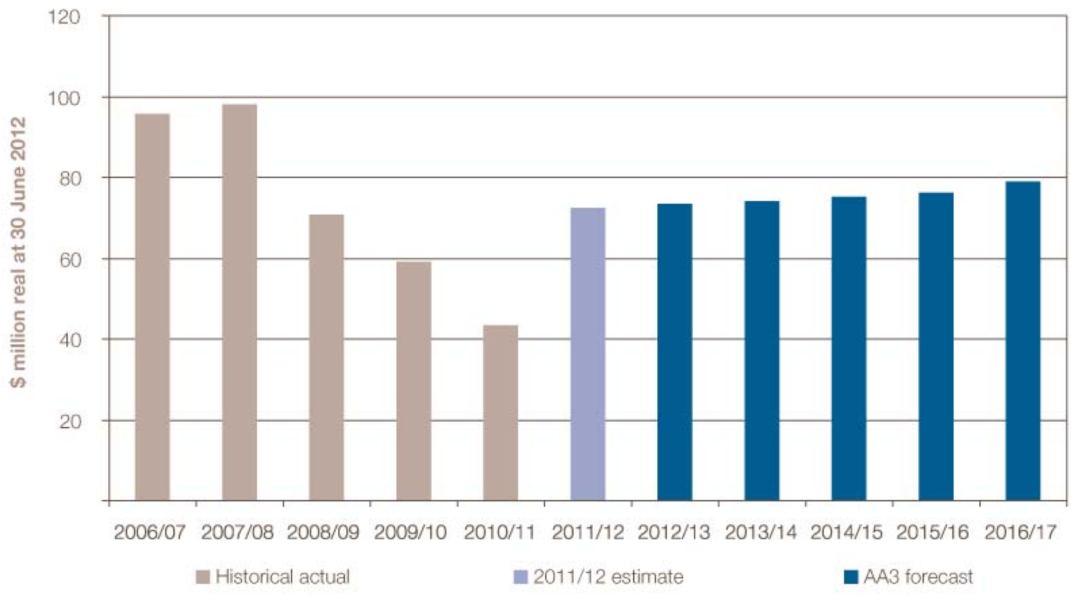

Figure 32: Transmission customer driven historical and forecast capital expenditure

New facilities investment test

New facilities investments in transmission customer driven projects are only undertaken where section 6.52(b) (i) of the Access Code is met or the connecting customer contributes that part of the investment that does not meet section 6.52(b). Section 6.52(b) (i) of the Access Code requires that *the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment*.

The connecting customer contributes that part of the investment that does not meet the section 6.52(b) of the Access Code, in accordance with the *Contributions Policy* developed under sections 5.12 to 5.17 of the Access Code. Under section 3 of the contributions policy:

> *A contribution with respect to covered services sought by an applicant must not exceed the amount that would be required by a prudent service provider acting efficiently, in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of providing the covered services.*

AA3 transmission customer access contributions have been forecast in line with historical ratios of contributions to expenditure as outlined in chapter 8 of the AAI. In the Authority's *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network* it was noted:

> *On the basis of the ratios of contributions to levels of customer driven investment, the Authority accepts that the forecast of contributions is reasonable and the residual values of investment may reasonably be expected to satisfy the second part of the new facilities investment test under section 6.52(b) of the Access Code.*

The net AA3 expenditure (residual investment value) has been assessed as meeting section 6.52(b) (i) of the Access Code. We enter into or amend an existing electricity transfer access contract at the time of committing to undertake network augmentations to connect customers or to amend an existing connection point. The electricity transfer access contract outlines the capacity required for the customer's new facility, the access tariff to be applied and the number of years for which the connection point will be in use. Therefore, the electricity transfer access contract provides sufficient certainty that we will secure incremental revenue for the augmentation.

AA3 transmission customer driven expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. We consider that the Access Code requirements are best satisfied if growth-related investment is based on historical expenditure, adjusted for identifiable drivers. This ensures that prices are not increased above levels that have been sufficient to meet customer's needs in the past.

The investment adjustment mechanism also ensures that we are able to invest efficiently in customer driven capital expenditure if necessary.

Relocation of existing assets generally does not satisfy section 6.52(b) of the Access Code and hence contributions are generally sought from the party requesting the relocation for the full amount of the efficient investment in these works.

Appendix 8 of the Access Code applies to relocations of existing network assets. The full cost of these works is efficient because:

> *A contribution for Appendix 8 work (other than a flat fee under clauses A8.5 and A8.17) must not exceed the forecast cost that would be forecast to be incurred for the work by a service provider efficiently minimising costs*[42]

REGULATORY OBLIGATIONS

The Access Code places obligations on us to connect customers to its network.

Section 2.7 of the *Access Codes* requires that:

A service provider for a covered network must use all reasonable endeavours to accommodate an applicant's:

a) requirement to obtain covered services; and

  a) (b) requirements in connection with the negotiation of an access contract

Further, section 2.8 of the *Access Codes* states that:

Without limiting section 2.7, a service provider must:

a) comply with the access arrangement for its covered network and must expeditiously and diligently process access applications; and

b) negotiate in good faith with an applicant regarding the terms for an access contract; and

c) to the extent reasonably practicable in accordance with good electricity industry practice, permit an applicant to acquire a covered service containing only those elements of the covered service which the applicant wishes to acquire; and

d) to the extent reasonably practicable, specify a separate tariff for an element of a covered service if requested by an applicant, which tariff must be determined in accordance with sections 10.23 and 10.24; and

e) when forming a view as to whether all or part of any proposed new facilities investment meets the test in section 6.51A, form that view as a reasonable and prudent person

Access applications are processed in accordance with the applications and queuing policy developed under sections 5.7 to 5.11 of the *Access Code*.

We are not obliged to relocate our assets when requested to do so by an outside party. However, we will assist other parties by relocating assets at their request on a fee-for service basis. This service is provided with the following conditions:

- the proponent funds the total actual cost for Western Power to undertake the works
- the relocation will not disadvantage any third party
- the relocation will not disadvantage any third party

A breakdown of AA3 forecast transmission customer driven expenditure by activity is shown in Table 37. Customer access works account for 87% of expenditure and line relocations for the remaining 13%. These two activities are discussed in the following sections.

[42] Section A8.3 of the Access Code

Table 37: AA3 Transmission customer driven expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Customer access	63.8	64.4	65.4	66.3	68.7	328.7
Line relocations	9.5	9.6	9.8	10.0	10.3	49.3
Gross customer driven total	73.4	74.0	75.2	76.3	79.0	377.9
less capital contributions	41.4	41.8	42.5	43.1	44.7	213.6
Net customer driven total	**31.9**	**32.2**	**32.7**	**33.2**	**34.3**	**164.3**

6.1.2.1 Customer access

In AA3 we will invest $329 million, 87% of forecast customer driven expenditure, to provide our customers with access to the transmission network. We have forecast customer access expenditure using the historical average of the four year period from 2006/07 to 2009/10, taking into account the impact of forecast movements in the price of labour and materials.

The Karara Mining Limited iron ore and magnetite mine located near Three Springs and the Southdown Mine for Southdown Joint Venture are two major augmentations proposed for delivery during AA3. Given contracts have not yet been entered into between the parties we have not included expenditure for these projects over and above the historical average. We consider that the Access Code requirements are best satisfied if growth-related investment is based on historical expenditure, adjusted for identifiable drivers. This ensures that prices are not increased above levels that have been sufficient to meet customer's needs in the past. The investment adjustment mechanism also ensures that we are able to invest efficiently in customer driven capital expenditure if necessary.

The customers that require individual expansion or reinforcement works range from discrete bulky loads (such as new mining projects) and large generators, to small/medium enterprise loads (such as mineral processing facilities) and small renewable generators (such as wind turbines).

Transmission customer access works include any new or modified network assets required to connect the customer's premises to the network. The type of work required to connect a customer may include one or more of the following:

- new transmission lines (or cut-in lines) from a customer's point of connection to the nearest Western Power substation (or Western Power transmission line)
- new substation equipment such as a bay to accommodate the connection (and associated works such as circuit breakers and protection relays)
- new transmission switchyards including transformers, usually to connect major loads and/or generators

There may be other work types that apply and these are determined by assessing a customer's application to connect on a case-by-case basis.

If deep network reinforcement is required to supply a new connection, customers can choose to:

- pay a contribution for financing costs to bring forward our planned deep network reinforcements to meet their project timeframes (where feasible)
- accept curtailment of load (restricted supply) or runback schemes for generators (restricted output) under certain network conditions as a temporary measure

This approach offers connecting customers flexibility and choice while ensuring service standards are maintained to existing customers. The option of curtailment and runback schemes allows us to manage investment in the transmission network in an efficient manner; ensuring works are delivered when there is a firm obligation. These schemes are only designed to be temporary measures given:

- Western Australia's market rules require generators to be available to generate under all network conditions given the unconstrained nature of network access
- if Western Australia moved to constrained network access and market operation, System Management would need to be significantly resourced and market rules amended to accommodate a system whereby network constraints can be managed

6.1.2.2 Line relocations

In AA3 we will invest $49 million, 13% of forecast customer driven expenditure, to relocate transmission lines on request by customers. This is consistent with the expenditure over the previous five year period, excluding the impact of forecast movements in the price of labour and materials, consistent with the forecasting methodology.

We relocate transmission lines and assets (66 kV or above) to accommodate the needs of external parties. For example, we may relocate a transmission line at the request of a shopping centre developer to remove the physical impediment of the line and allow the development to proceed, while keeping the integrity of the electricity network intact.

Where transmission assets are required to be relocated, we will assess the scope of the works for opportunities to make maximum use of the outage or asset removal and relocation. For example, if a pole to be relocated is near the end of its serviceable life, it can be replaced in its new location with a new pole. Benefits to Western Power are taken into account when calculating the contribution payable by the customer.

6.2 Asset replacement and renewal

We deliver our transmission asset replacement and renewal capital investment through the discrete regulatory category of asset replacement, driven by the age, condition and performance of individual assets.

6.2.1 Asset replacement

In AA3 we will invest $173 million, 9% of forecast transmission network capital expenditure, to replace or reinforce transmission assets.

This category of investment mainly includes volumetric programs of work forecast by prioritising investment on those assets in the worst condition, as determined from condition monitoring and inspection programs, and applying cost building blocks.

In AA3 we will increase replacement levels for indoor circuit breakers (also known as switchboards to distinguish them from outdoor circuit breakers). Four catastrophic failures of circuit breakers in pitch-filled type switchboards have contributed to 35% of the indoor circuit breaker population being assessed as being in poor or bad condition and in need of replacement. In contrast, average annual spend on other programs of asset replacement is relatively consistent with AA2 investment levels.

Figure 33 shows the impact of the indoor circuit breaker replacement program in AA3 on the overall trend in transmission asset replacement expenditure.

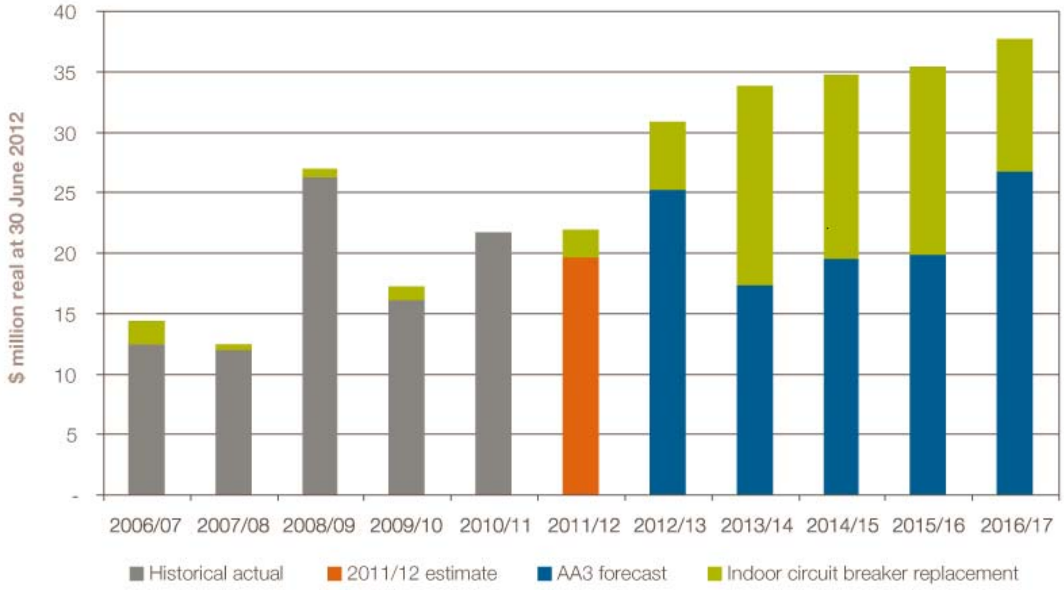

Figure 33: Transmission asset replacement historical and forecast capital expenditure

New facilities investment test

New facilities investments in transmission asset replacement are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 transmission asset replacement expenditure has been assessed as meeting section 6.52(b) (iii) of the Access Code. As outlined in the Network Management Plan, evidence from condition monitoring and inspections have been relied upon to demonstrate that there is a high likelihood that the safety or reliability of the covered network will not be maintained if not for the investment.

AA3 transmission asset replacement expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. In addition, we will continue to employ smart planning initiatives to bundle transmission asset replacement and maintenance activities to reduce planned outages and therefore efficiently minimise costs, primarily for our mobilisation and demobilisation costs. Specifically, this has meant we are able to reduce average annual investment levels compared to the AA2 period on protection relays by carrying out this activity only when the primary plant associated with the relay is replaced or refurbished.

REGULATORY OBLIGATIONS

The regulatory obligations that are relevant to investment in distribution asset replacement are summarised below.

Section 14 of the *Electricity Industry Act 2004* requires us to have an effective asset management system:

1. *It is a condition of every licence, other than a retail licence, that the licensee must -*
   - *(a) provide for an asset management system in respect of the licensee's assets;*
   - *(b) notify details of the system and any substantial changes to it to the Authority; and*
   - *(c) not less than once in every period of 24 months (or any longer period that the Authority allows) calculated from the grant of the licence, provides the Authority with a report by an independent expert acceptable to the Authority as to the effectiveness of the system.*
2. *An asset management system is to set out measures that are to be taken by the licensee for the proper maintenance of assets used in the supply of electricity and in the operation of, and, where relevant, the construction of, any generating works, transmission system or distribution system*

The *Electricity (Supply Standards and System Safety) Regulations 2001* require prudent levels of asset replacement to deliver acceptable public safety outcomes. Section 10 sets out requirements for management the prescribed activities:

1. *A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to –*
   - *a) provide for the safety of persons, including employees of and contractors to the operator;*
   - *b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and*
   - *c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity*

We are also obliged, under sections 9 and 10 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (the Supply Code) to, as far as is reasonably practicable:

- ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum (section 9)
- reduce the effect of any interruption on a customer (section 10 (1)

It is through adequate levels of asset replacement that we are able to comply with the Supply Code and to ensure safety to people and property.

It is through adequate levels of asset replacement that we are able to comply with the Supply Code and to ensure safety to people and property.

A breakdown of AA3 forecast transmission asset replacement expenditure by activity (or asset class) is shown in Table 38 and Figure 34.

Table 38: AA3 Transmission asset replacement expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Circuit breakers	10.1	21.9	21.7	22.5	18.5	94.7
Instrument transformers	4.8	5.3	7.8	6.0	7.2	31.2
Power transformers	12.1	2.5	1.9	2.6	2.0	21.3
Protection	2.0	2.4	2.1	1.8	1.9	10.2
Static var compensator	-	-	-	1.1	6.8	7.9
Disconnectors	1.4	1.3	0.7	0.9	0.7	4.9
Surge arrestors	0.4	0.4	0.5	0.5	0.5	2.4
Asset replacement total	**30.8**	**33.9**	**34.8**	**35.4**	**37.8**	**172.6**

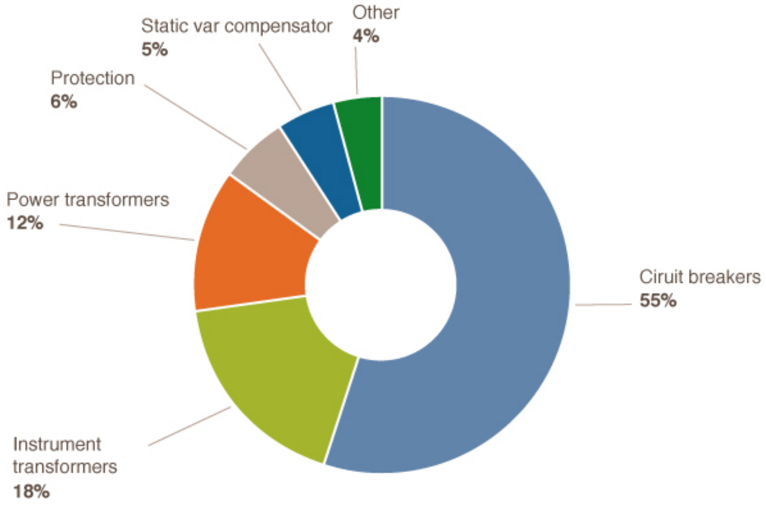

Figure 34: AA3 transmission asset replacement expenditure by activity

Each of these activities is discussed in the following sections.

6.2.1.1 Circuit breakers

In AA3 we will invest $64 million and $31 million, 55% of forecast transmission asset replacement expenditure, on indoor and outdoor circuit breakers, respectively. This increase on the previous five year period reflects the need to replace specific subsets of the asset population identified as being at high risk of failure due to Sulphur hexafluoride (SF_6) leaks and obsolescence issues.

By interrupting the flow of electricity in a section of the network when an abnormal condition is identified, circuit breakers are used to maintain system security, protect other network assets from damage and ensure the safety of personnel. Circuit breakers are therefore critical network assets and are managed as non-run to failure. Failure to carry out asset replacement programs brings a high risk of even more expense to repair costly damage from their unplanned failure under high load conditions.

There are 2,554 circuit breakers installed at terminal and zone substations across the Western Power Network. Circuit breakers operate at voltages from 6.6 kV through to 330 kV and are categorised according to installation type (indoors[43] or outdoors) and insulation medium (vacuum, gas (SF_6), or oil).

Service capability of the circuit breaker population is progressively being impacted by the gradual deterioration of insulation condition, worn contacts and the effect of extreme internal forces or temperatures during fault events. As at January 2011, 33% of the circuit breaker population were oil insulated, 43% were gas (SF_6) insulated and the remaining 23% vacuum insulated. Records of historical defects show that circuit breakers are the assets most prone to fail across the asset base, with most defects resulting from oil leaks, followed by gas related problems and an increasing occurrence of hydraulic operating mechanism failures.

[43] An indoor circuit breaker is part of a switchboard which includes the rack mountings and cabinets that are required to safely house the actual indoor circuit breakers

The condition assessment and resultant condition score for circuit breakers is based on diagnostic tests and inspection records as well as operational duty and the risk of contributed failures. Although circuit breakers and switchboards are condition managed, due to the correlation between age and asset condition it is useful to consider volume of assets nearing and within the expected life range of 40 – 50 years for forecasting purposes. The age profile over time for our indoor circuit breaker and outdoor circuit breaker population are shown in Figure 35 and Figure 36 respectively. The step increase in AA3 investment will address the increasing proportion of circuit breakers at risk and improve the average condition of the population.

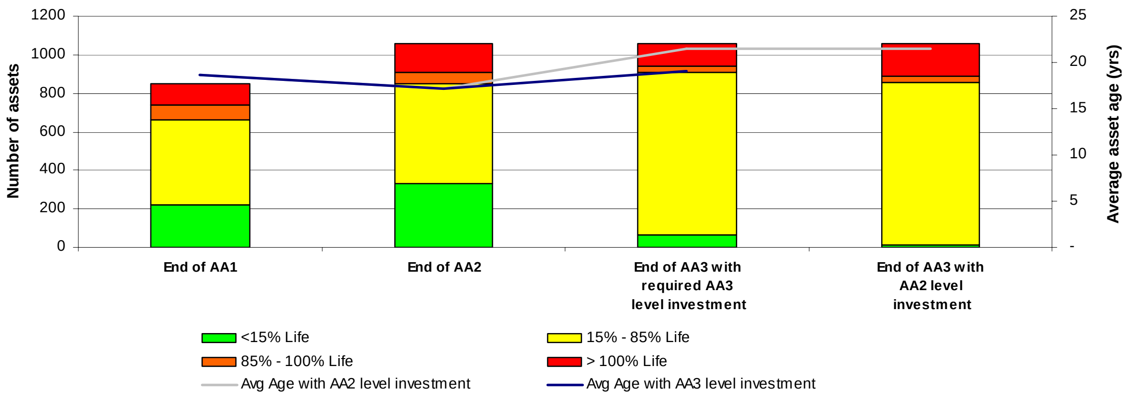

Figure 35: Transmission indoor circuit breaker age profile AA1 to AA3

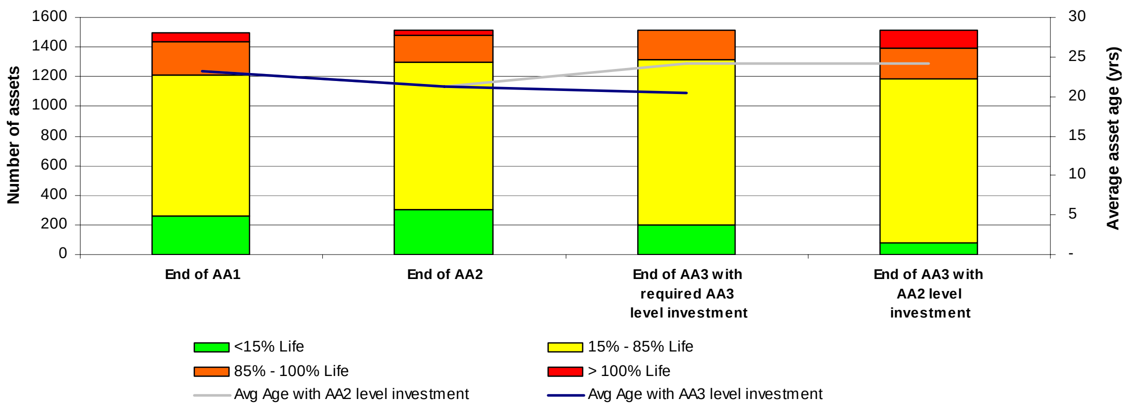

Figure 36: Transmission outdoor circuit breaker age profile AA1 to AA3

Indoor circuit breakers

Approximately 35% of the indoor circuit breaker population is classified as being in ‘poor’ or ‘bad’[44] condition.

Analysis of condition data shows that 25% of the total population is installed within pitch filled type switchboards and approximately half of those are considered in ‘bad’ condition. We have experienced four catastrophic failures of pitch filled type switchboards in the last 10

[44] The condition assessment criteria such as ‘poor’ and ‘bad’ are defined in Appendix L: Network Management Plan.

years. For that reason, they have a high risk of failure and consequently we have developed an end of life treatment strategy to address this problem.

Given the number of catastrophic failures experienced and the severity of consequences, we will replace eight of the 18 indoor switchboards (including circuit breakers) assessed to be in poor condition during AA3.

The remaining ten indoor switchboards will be either:

1. made redundant through other works enabling them to be decommissioned
2. optimised with other capacity expansion projects
3. targeted for replacement during AA4

Replacement will be prioritised based on condition, loading, availability of spares, location and risk within the network. While this is a relatively new program, we do not anticipate any issues in delivering this additional volume of work during AA3. A tender process will be set up for the program, with external resources supported by some internal resource capability.

Outdoor circuit breakers

There are specific operation and maintenance issues with some makes of outdoor circuit breakers:

- There are currently 29 GEC (FK1 and FE2) circuit breakers installed on the network. These families of circuit breakers have suffered severe SF_6 leaks and consist of mechanisms which are difficult to repair. As there is no manufacturer support for these units and spare parts are not available from any source, we are phasing out these units. Six of these outdoor circuit breakers will be replaced annually until fully removed from the network
- There are currently 81 Magrini Galileo (MMS 24C, 38MGE) and 52 English Electric (OKW3) outdoor circuit breakers installed on the network. These families of circuit breakers suffer from loss of insulation and difficulty in sourcing spares. As it is no longer possible to maintain these units due to unavailability of spare parts from any source, we are phasing out these units. Approximately twenty of these circuit breakers will be replaced annually until fully removed from the network

Typically capacitor switching requires circuit breakers with a special duty (more intensive). However, at several locations in the network, normal indoor and outdoor circuit breakers are used for the switching of power factor correction capacitors. These circuit breakers are subjected to frequent operations and more stresses during operations than intended, and are given condition ratings to reflect the more intensive duty. We have developed a maintenance strategy to periodically rotate these circuit breakers used in capacitor switching to even out the effect.

In AA3 we will replace 190 outdoor circuit breakers, reflecting an increased number of volumes on the previous period enabling us to reach a sustainable level of replacement and to address the obsolescence and type of issues identified above.

6.2.1.2 Instrument transformers

In AA3 we will invest $28 million and $3 million, 18% of forecast transmission asset replacement expenditure, to replace current and voltage (instrument) transformers, respectively. There is an urgent need to replace specific subsets of the asset population including types of current transformers which have failed recent testing, other types which are known to suffer from severe oil leaks and voltage transformers that are contaminated with Polychlorinated Biphenyls (PCBs)[45].

Instrument transformers (current transformers (CTs), voltage transformers (VTs) and capacitive voltage transformers (CVTs)) are located at terminal and zone substations. Their main function is to measure the network current and voltage at a specific location for protection, control and operation purposes. Instrument transformers are critical elements of a transmission system to ensure secure operation of the network. Incorrect operation or failure of an instrument transformer can have a material impact on the safety of the equipment it is designed to protect and impact network reliability.

Table 39 summarises the number of instrument transformers in the network, by voltage level.

Table 39: Instrument transformer population in the Western Power Network

Type	11 kV	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Current transformers	118	1,435	353	564	1,836	72	221	4,599
Voltage transformers	2	21	58	210	886			1,177
Combined units		1	1	24	107		12	145
Capacitive voltage transformers					58	36	190	284

Current transformers

Approximately 13% of the CT population has been identified as being in poor or bad condition. In addition, there are specific operation and maintenance issues with some specific makes of CTs installed on the Western Power Network:

- older ASEA (IMBA) 66 kV and 132 kV current transformers – the design is inadequate due to changes in network conditions, demonstrated by 6 CTs which have failed testing
- Westralian 22 kV current transformers (approximately 2% of the total CT population) – have known tracking issues and suffer from severe oil leaks

In AA3 we will replace 450 CTs, or 9.8% of the population, to address known issues with CTs at risk of failure or that pose safety and environmental risks.

Voltage transformers

Approximately 11% of the VT population has been identified as in poor or bad condition. In addition, there are specific operation and maintenance issues with some makes of VT.

- ASEA and Haefely type 132 kV voltage transformers (approximately 25% of the VT population) suffer from oil leaks. These oil leaks have led to increased maintenance frequency, requiring additional system outage requests and increased operational costs
- Koncar voltage transformers (<10 years old) suffer from oil leaks which cannot be controlled through maintenance

In AA3 we will replace 100 VTs, or 8.5% of the VT population, to address known issues with oil leaks that increase the risk of failure or pose safety and environmental risks.

[45] Toxic chemicals used in older style assets

6.2.1.3 Power transformers

In AA3 we will invest $21 million, 12% of forecast transmission asset replacement expenditure, to replace power transformers. This reflects the urgent need to replace power transformers that have been assessed as being in poor or bad condition and are at increased risk of unplanned failure.

The population of power transformers on the Western Power Network consists of 339 in-service power transformers, 7 spares and 4 rapid response transformers. These are located in 24 terminal stations and 114 zone substations throughout the Western Power Network with primary voltages varying from 22 kV to 330 kV and secondary voltages varying from 6.6 kV to 220 kV.

Power transformers are very high value assets critical to maintaining reliable supply to our customers and are hence managed as N-RTF. A failure can have a major impact on network reliability, the environment and our key performance indicators.

Power transformers are replaced based on condition. However, due to the correlation between age and asset condition it is useful to consider the volume of assets nearing and within the expected life range of 40 - 50 years. Approximately 35% of the population are over 40 years old, with service capability progressively being impacted by the gradual deterioration of insulation condition, oil quality and the effect of extreme internal forces or temperatures during fault events.

Power transformers rarely have a clear-cut diagnosis for refurbishment, replacement or other end of life treatments on the basis of a single technical indicator. Condition assessment for power transformers is based on the following main key assessments:

- dissolved gas analysis
- high voltage electrical diagnostic tests
- condition contributing factors including loading tap changers
- severity

By combining a number of condition assessment indicators and observing their relationships over time, we have established a composite view of the health of each power transformer on the network. 7% or 24 of the power transformer population have been assessed as being in bad condition, as shown in Figure 37.

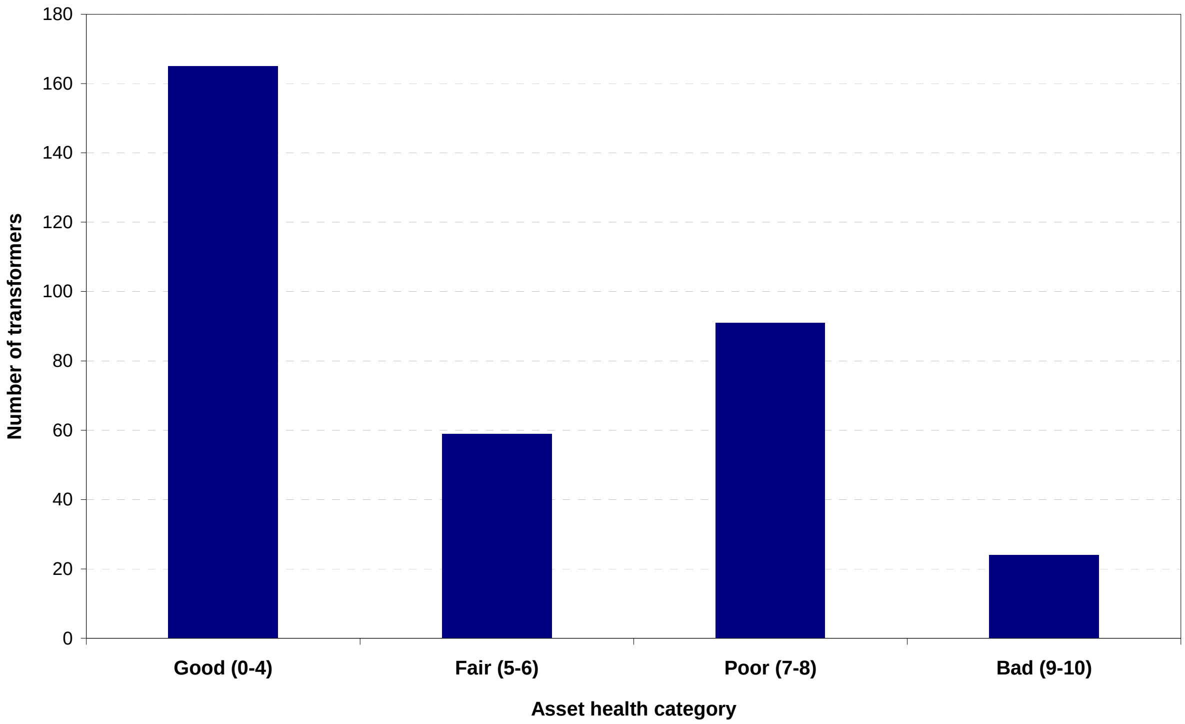

Figure 37: Power transformer condition profile

In AA3 we will replace 10 of the 24 bad condition power transformers with the remaining 14 units to be delivered via growth programs (where possible) or targeted for replacement during AA4. The power transformers replaced will be prioritised based on condition, loading, availability of spares, location and risk within the network.

6.2.1.4 Protection

In AA3 we will invest $10 million, 6% of forecast transmission asset replacement expenditure, to replace protection relays and associated equipment.

The main function of a transmission protection relay is to identify abnormal operating conditions in the network and send appropriate tripping signals to the circuit breakers. The circuit breakers then rapidly operate to isolate the affected components so that the rest of the network can be operated safely. Typically protection relays obtain appropriate input signals from the instrument transformers and other relays installed at various locations on the transmission network.

Failure of a protection relay can have a material impact on the safety of other equipment and network reliability and hence these assets are managed as N-RTF. Although, sufficient redundancies are included in protection system design to ensure secure and reliable operation of the network in case of a protection relay failure.

There are 29,859 protection relays and 5,435 protection schemes in service at 149 substations across the Western Power Network. Protection relays can be broadly categorised into three groups based on their construction; these are electromechanical, solid-state and numerical relays.

The performance of protection systems is measured using an Overall Protection Performance Index (OPPI) target of 96%. Performance against this indicator declined in 2010/11 due to:

- several mal-operation incidents of frame leakage protection in Milligan St (2 false trips) and Piccadilly substations (4 false trips), causing major blackouts in the Perth CBD and Goldfields areas
- incorrect operations of GE type T60 (transformer protection) causing partial (or total) blacking out of substations by inadvertent operation without primary faults
- incorrect operations of GE type F60 (feeder protection) relays throughout the network causing partial (or total) blacking out of substations by going into a lockout mode while clearing faults

In addition to the problems experienced with the GE T60 and F60 protection relays, the GE L90 line protection relays have been going into failure mode when the communication channel is restored after fading out. We currently have 338 of these relays installed on the Western Power Network.

Condition assessment is used to identify the protection relays that are reaching the end of their reliable operational life.

Treatment for protection relays is applied on a case by case basis taking into account obsolescence, failure rates and spares stock levels (for obsolete models). End of life strategies can be undertaken as standalone relay replacement programs (as conducted in AA2) for particular obsolete types with high failure rates or as part of replacement or refurbishment programs on the primary plant associated with the relay.

In AA3 we will target ten schemes for protection relay replacement annually on an ‘as needed’ basis and when replacement and refurbishment works occur on the related primary plant. We are able to reduce average annual investment levels compared to the AA2 period by bundling these works with other asset replacement or regulatory compliance activities to efficiently minimise costs.

6.2.1.5 Static var compensators

In AA3 we will invest $8 million, 5% of forecast transmission asset replacement expenditure, to replace static var compensators (SVCs). There were no SVC replacements in the AA2 period.

There are three SVCs in the Western Power Network. SVCs on the Eastern Goldfields Interconnected System provide dynamic reactive power support to the 220/132 kV system supplying the Kalgoorlie area enabling the 220 and 132 kV voltage levels to be automatically controlled under varying power transfer and plant outage conditions. This maintains the voltage and power transfer stability of the system, ensuring compliance with section 2.3.7: *Power System Stability and Dynamic Performance,* of the *Technical Rules*. Without the SVCs in service, the supply system to the Eastern Goldfields would (under certain conditions) collapse and adversely affect supplies to areas such as the major regional centres of Kalgoorlie and Merredin.

The condition of the SVCs serving West Kalgoorlie and Merredin has been closely monitored over several years. While maintenance has been increasing, the high cost of replacing these assets means that it is not prudent to make the capital investment until absolutely necessary. The SVCs at West Kalgoorlie and Merredin have deteriorated drastically over the AA2 period and urgent attention is required to prevent them from failing in service. In addition, the SVC cooling systems (reactor coolers) have suffered from severe oil leaks with the coolers heavily clogged with dust, bugs and rodents. These have required extensive maintenance since 2002.

The SVCs at West Kalgoorlie are scheduled for replacement in 2016. Rather than proceeding with like for like replacements, the optimum long term solution is to replace the asset with static synchronous compensator (STATCOM)[46] or similar new technology device. This option has the following benefits:

- avoids significant expenditure to proceed with separate asset replacement for *bad* condition assets associated with the SVC including the saturated reactors, cooling systems and programmable logic controllers
- reduces maintenance costs due to wear on moving parts and oil leaks on ageing assets
- mitigates risk of technological obsolescence of equipment and availability of spares and realises the benefits of introducing next generation technologies
- reduces unplanned outages due to equipment failures
- supports compliance with environmental legislative obligations for oil containment, PCBs and asbestos

The saturated reactor SVCs at West Kalgoorlie will be replaced with three modern 45 Mega Volt Ampere Reactive (MVAR)[47] reactive devices (combination of capacitor banks and STATCOMs or similar). Two of these reactive devices will be direct replacements for the existing ‘bad’ condition units and the third is required to provide additional reactive power to support the Eastern Goldfields area when there is a loss of one of the STATCOMs.

It is expected that further investment will be required early in AA4 for the replacement of the SVC at Merredin.

6.2.1.6 Other

The following activities are individually less than $5 million per program over the AA3 period or below 3% of forecast transmission asset replacement and renewal expenditure.

- Disconnectors ($4.9 million) - to ensure that service standards are maintained and continued compliance with the technical rules, this program will replace 8.2% of disconnectors over the AA3 period prioritised according to performance, risk of failure and safety.
- Surge arrestors ($2.4 million) - is the replacement of surge arrestors that have been identified in 'bad' condition or have reached the end of their life cycle. This program will maintain our current levels of network reliability performance through adequate levels of replacement and ensure safety to people and property as required under the Electricity Industry (Network Quality and Reliability of Supply) Code 2005.

6.3 Improvement in service

In AA3 we will invest $79 million, 4% of forecast transmission network capital expenditure, on ‘improvement in service’ works.

[46] A regulating device used on alternating current electricity networks.
[47] A measure of power due to the various “real-life” reactive elements of an alternating current electricity network.

We deliver these projects and programs through two distinct categories:

- *reliability driven* – targeted programs to improve the reliability performance and security of the network to achieve the minimum service standard benchmarks outlined in the Access Arrangement
- *SCADA and communications* – to enable the real-time monitoring and automation of our transmission assets

6.3.1 Reliability driven

We have not forecast any specific investment to target transmission reliability improvement in AA3. Should we identify any individual reliability improvement projects that will have a measurable effect on average service performance; we will pursue these during AA3 only where the service incentive rewards under the service standard adjustment mechanism outweigh the cost.

6.3.2 SCADA and communications

In AA3 we will invest $79 million, 4% of forecast transmission network capital expenditure, in transmission SCADA and communications.

SCADA and communications expenditure enables us to continuously monitor and control the network to:

- meet power system performance standards
- discharge our responsibility as the transmission network operator to provide operational co-ordination of the power system under the *Wholesale Electricity Market (WEM) Rules*
- comply with *Technical Rules* for the provision of transmission system protection

As well as offering instantaneous remote visibility and control of vital functions, SCADA includes the benefit of protecting the operators of the equipment by removing the need to be physically present in the hazardous environments that exist in these systems.

Investment in SCADA and communications will increase from historical levels from 2011/12 onwards, primarily due to the upgrade of the hardware and software of our master station (for control of the network) as shown in Figure 38. This project will continue to 2016/17.

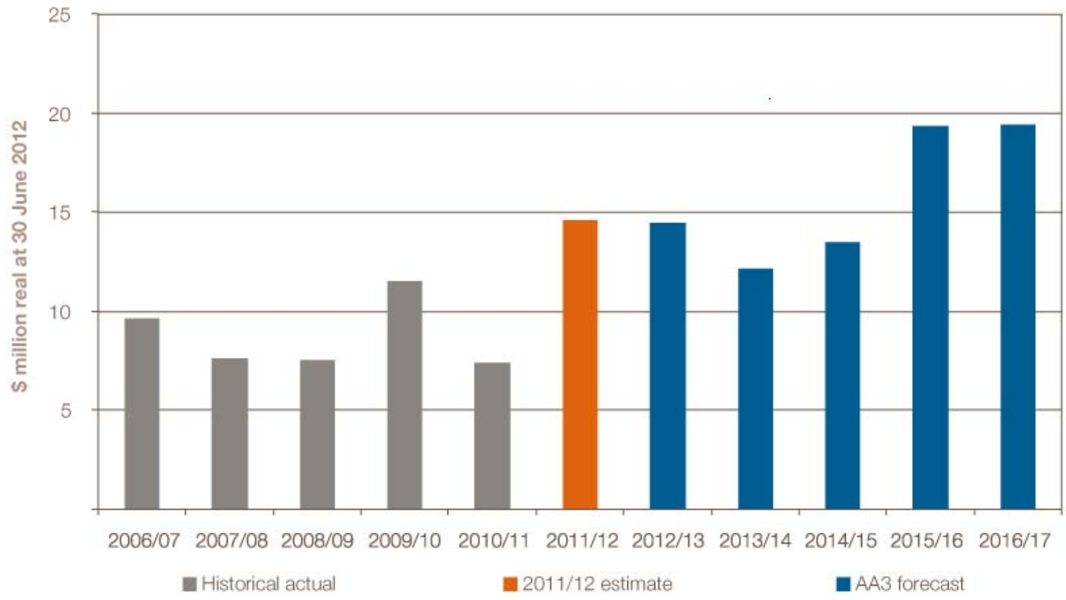

Figure 38: Transmission improvement in service historical and forecast capital expenditure

New facilities investment test

New facilities investments in transmission SCADA and communications are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 transmission SCADA and communications expenditure has been assessed as meeting section 6.52(b) (iii) of the Access Code. Without this investment, both the safety and the reliability of our network is at risk because of the less than optimal remote visibility and control required to effectively manage transmission power network assets.

AA3 transmission SCADA and communications expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. In addition, we maintain common SCADA and communications assets and systems across many areas of the network in a centralised model to optimise investment and efficiently minimise costs. Typically such efficiencies of scale and scope are realised when digital control, monitoring and communications functions are aggregated for transmission primary network assets that are located at the same site.

REGULATORY OBLIGATIONS

Investment in SCADA and communications ensures we meet the requirements for continuous network control and monitoring to:

- meet power system performance standards (*Technical Rules* sections 2.2, 2.3.9, 3.2.1, 3.3 and 5.3.1)
- discharge our responsibility to provide operational co-ordination of the power system and wholesale electricity market rules (Wholesale Electricity Market Rules sections 3.2.8, 6.13.1 and 7.13)
- comply with *Technical Rules* for the provision of transmission system protection (sections 2.9.1, 2.9.2 and 2.9.3)
- upgrade our communications facilities to comply with the *Telecommunications Act 2004* and to manage and meet the related obligations

A breakdown of AA3 forecast transmission SCADA and communications expenditure by activity is shown in Table 40 and Figure 39.

Table 40: AA3 transmission SCADA and communications expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Asset replacement	6.0	10.5	11.6	14.5	16.0	58.5
Improvement in service	2.4	1.0	1.2	2.3	2.7	9.5
Core infrastructure growth	3.6	0.1	0.3	0.8	0.4	5.3
Performance and regulatory	2.3	0.5	0.4	0.5	0.3	4.0
Third party actions	0.1	0.1	-	1.2	-	1.5
SCADA and communications total	**14.4**	**12.2**	**13.5**	**19.3**	**19.4**	**78.8**

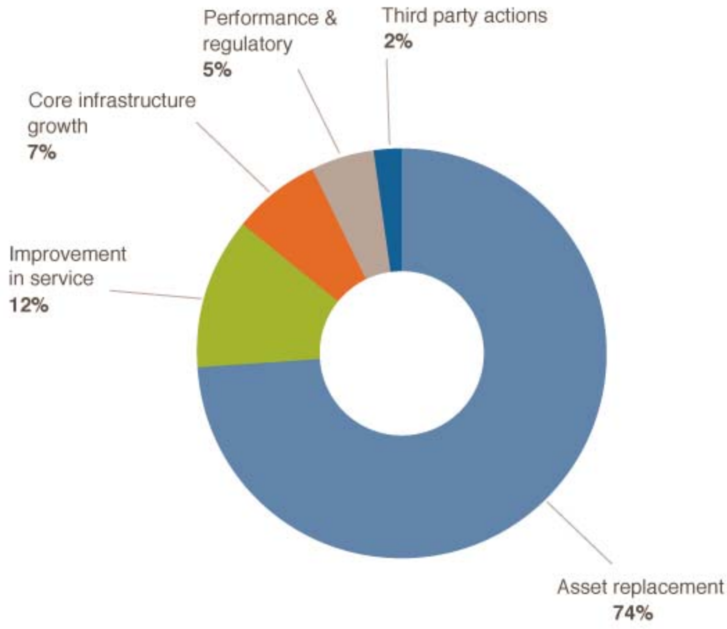

Figure 39: AA3 transmission SCADA and communications expenditure by activity

Each of these activities is discussed in the following sections.

6.3.2.1 Asset replacement

In AA3 we will invest $59 million, 74% of forecast transmission SCADA and communications expenditure, to replace critical systems infrastructure. This is an increase from previous levels of investment reflecting the upgrade of the XA-21 Master Station and completion of a number of large microwave replacements.

SCADA and communication assets are replaced when they fail to meet their intended functionality, have reached the end of their support and product life cycle, or have reached their capacity limitations. Replacement cycles typically vary between 5 and 15 years for these types of assets.

Asset replacement expenditure forecasts are derived from historical expenditure levels, adjusting where necessary using an assessment of secondary system asset age and condition and taking into account network growth. The assessment of the age and condition of SCADA and communications infrastructure is captured annually in the secondary systems state of the network report.

Three key programs for the AA3 period are discussed below being master station replacement, microwave bearer and pilot cable replacement works. Table 41 demonstrates the relative proportion of these three programs to total SCADA and communications asset replacement expenditure.

Table 41: AA3 transmission SCADA and communications asset replacement expenditure ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Other minor asset replacement	2.0	4.2	4.7	5.3	7.9	24.2
Master Station XA/21	2.8	3.2	2.8	3.1	3.5	15.5
Microwave bearers	0	1.7	2.8	4.8	3.2	12.5
Pilot cable	1.2	1.4	1.3	1.3	1.3	6.4
Total SCADA and communications asset replacement	**6.0**	**10.5**	**11.6**	**14.5**	**16.0**	**58.5**

Master station XA/21

In AA3 we will invest $15 million to continue the program of replacement of critical elements of the transmission master station works that commenced in AA2. The master station, also known as the XA/21 Energy Management System (EMS), is the business critical system that provides the ring-fenced System Management real-time visibility and control of the generation and transmission network, including outage and fault management, and provides data to support the *Wholesale Electricity Market (WEM) Rules*. The control area is the Western Power Network with control of all generating stations terminals and zone substations to the feeder level.

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

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

Microwave bearers

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

In order to reduce the risk of lengthy failures[48] posed by the existing microwave systems, a rolling program of asset replacement will remove Plesiochronous Digital Hierarchy (PDH)[49] links that have been identified as presenting the highest risk and cost burden to Western Power with new, well supported, higher bandwidth and more flexible Synchronous digital hierarchy SDH[50] microwave bearer links. Continued asset replacement of islanded and no longer manufactured microwave radio links with PDH - SDH compatible systems will facilitate migration from PDH to SDH.

Pilot cable

In AA3 we will invest $6 million to replace pilot cables with optical fibre cable or upgrade connections to a digital communication system to maintain reliability of the communications network and its data circuits. Pilot cables are shielded multi-core cables installed between Western Power substations. These cables primarily carry protection circuits, but are also used to carry voice and data circuits.

The suggested life of pilot cables varies between 20 and 30 years. Of the 900 km of pilot cable installed on the Western Power Network, 90% are over 25 years old. Pilot cables suffer from exposure to damage by the public (70% are overhead cables), channel instability caused by water ingress, external interference and other factors.

In AA3 thirteen sites will have their existing pilot protection upgraded to digital protection systems, utilising existing available digital communication systems. The circuits that will be transferred away from pilot cables and on to the digital communication network are mainly located in the metro area and extending from the central control centre. In addition, approximately 15 of the most defective pilot cables will be replaced with optical fibre cable. This replacement program will extend into AA4.

Other

In AA3 we will invest $24 million to replace other SCADA and communications equipment necessary for operating the network. This will include $17 million on the replacement of communications infrastructure such as network equipment system (NMS) equipment, PDH and tele protection system (TPS) equipment. A further $6.7 million will be spent on replacing SCADA assets including remote terminal units (RTU), human machine interface (HMI) and global positioning system (GPS) clock replacement.

6.3.2.2 Improvement in service

In AA3 we will invest $10 million, 12% of forecast transmission SCADA and communications expenditure, on providing continuous service improvements and enhancements to SCADA and communications assets.

[48] As existing parts are now obsolete and not supported by the manufacturer, a failure of the microwave system would result in the system not being available for a significant duration.
[49] A digital communications technology
[50] A high speed digital communication technology

SCADA and communications technology is associated with constant and rapid technological change. The major portion of AA3 improvement expenditure is targeted at upgrading the communication network management system, enhancing the energy management system (EMS) and substation ethernet access link upgrade projects. The upgrades and enhancements projects will:

- improve the efficiency in fault restoration management by interfacing the fault recorder information to the EMS
- improve the safety and security of network operation by superimposing fire weather warnings over the transmission network and enhancing the EMS digital metropolitan services system interface link to enable transfer of safety documents and tags
- improve the effectiveness of network operations during constrained conditions by introducing smartness to the EMS such as auto switching schemes and dynamic ratings
- improve supply restoration times for the loss of a primary transmission asset by introducing self-healing functionality at select zone substations
- improve customer interface by providing real time transmission outage status to call takers

6.3.2.3 Core infrastructure growth

In AA3 we will invest $5 million, 7% of forecast transmission SCADA and communications expenditure, to expand core SCADA and communications infrastructure to meet growth needs.

Core infrastructure needs to be constantly extended to support demand for increasing bandwidth applications and underpin the core bearer networks (carriers of communications signals) to ensure redundant, high availability systems. System availability and redundancy are requirements of the *Technical Rules*, sections 2.9.2 and 2.3.9(a).

Timing of core infrastructure growth works is dependent on the capacity expansion and growth projects they support. In AA3 this investment will install microwave bearers to facilitate growth projects (as distinct from replacement) including the Albany digital bearer (commenced in AA2), Kalgoorlie digital bearer and the Millendon to Muchea bearer branch.

6.3.2.4 Performance and regulatory

In AA3 we will invest $4 million, 5% of forecast transmission SCADA and communications expenditure, on performance and regulatory compliance works relating to core SCADA and communications infrastructure.

The purpose of this activity is to ensure we meet regulatory and performance requirements. These include the radio frequency spectrum changes legislated by Australian Communication and Media Authority (ACMA), safety requirements for communication sites and *Technical Rules* compliance. Examples of how these regulations influence investment include:

- changes to the radio frequency spectrum legislated by ACMA compel us to change communication equipment to ensure compliance and maintain conformity with the *Technical Rules* and the *Wholesale Electricity Market Rules*
- where we have identified works to improve compliance to the *Electricity Industry Metering Code 2005*

- anti-climb installation on communication towers will ensure compliance to the *Radio Communications Act 1992*[51] (Radio Frequency Radiation Isolation)

6.3.2.5 Third party actions

In AA3 we will invest $1.5 million, 2% of forecast transmission SCADA and communications expenditure, to address third party influences on our SCADA and communications system.

This activity caters for the actions of third parties which impact on our SCADA and communications systems. This can take the form of changes to external standards or the removal of services or mandatory infrastructure sharing (such as communication towers) that are wholly owned by Western Power.

The known third party projects in the AA3 period include the proposed changes by:

- Verve – proposing decommissioning Muja and Kwinana Power station generating units ‘A’ and ‘B’. When this occurs, we will be required to rearrange and install control and monitoring equipment at the Kwinana 132 kV switchyard
- ACMA spectrum revisions – changes to spectrum area, specifically speaking with respect to frequency/ bandwidth
- Telstra – proposed changes to their line services provided to substations which require works to address induced voltages on SCADA and communications equipment, to reduce safety risks to Western Power personnel.

6.4 Compliance

We deliver all of our transmission compliance capital expenditure through the discrete category of regulatory compliance, to meet external regulatory and legislative obligations, including technical and safety requirements.

6.4.1 Regulatory compliance

In AA3 we will invest $121 million, 6% of forecast transmission network capital expenditure, to improve compliance levels with our regulatory and legislative obligations.

Transmission regulatory compliance expenditure is one component of the total investment required to ensure compliance to all our obligations relating to performance and management of transmission network assets. Investment in this category specifically targets step changes, new obligations or identifies issues with current compliance levels, ensuring there is no overlap with investment in other categories. Consequently, historical trends are not indicative of future levels of investment.

Figure 40 shows our transmission compliance expenditure over the AA1 to AA3 period. The increased investment late in AA2 and into AA3 will:

- reduce the number of unassisted pole failures to meet industry benchmark levels in AA4 through increased volumes of reinforcing and replacing transmission poles
- reduce the risk of breaching *Electricity (Supply Standards and System Safety) Regulations 2001* as a result of cross-arm and cross-beam failure by increased reinforcing and replacement of cross-arms and cross-beams identified through a wide-scale structural assessment

[51] Available at: http://www.acma.gov.au/WEB/STANDARD..PC/pc=PC_1289

- reduce the risk of electrocution by improving safety for the public and our employees by bolstering security to prevent unauthorised access to 22 substations and carrying out safety upgrades in 73 substations

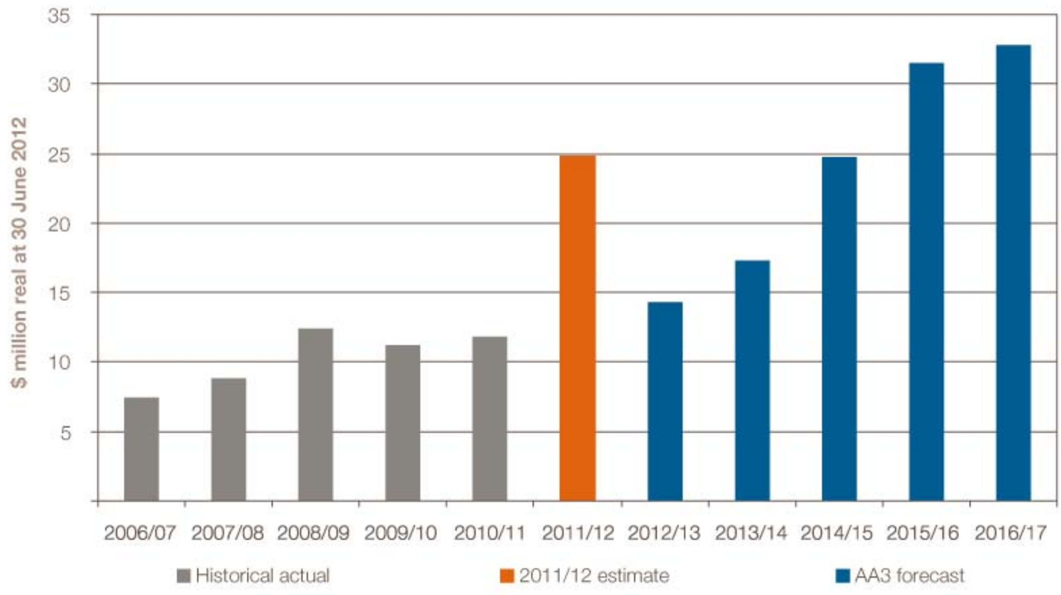

Figure 40: Transmission regulatory compliance historical and forecast capital expenditure

New facilities investment test

New facilities investments in transmission regulatory compliance are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 transmission regulatory compliance expenditure has been assessed as meeting section 6.52(b) (iii) of the Access Code. Non-compliance with relevant codes and standards is the evidence used that there is a high likelihood that the safety or reliability of the covered network will not be maintained if not for the investment.

AA3 transmission regulatory compliance expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI.

REGULATORY OBLIGATIONS

The *Electricity (Supply Standards and System Safety) Regulations 2001* require that we must ensure that, so far as is reasonable and practicable, we carry out our activities in such a way as to provide for the safety of persons, including employees of and contractors to us. Evidence of compliance with this regulation is defined in section 11(1):

Compliance by a network operator to whom Division 2 applies with a relevant provision of —

- *a) a standard or code published under a law any jurisdiction in Australia*
- *b) a standard or code published by Standards Australia, the Electricity Supply Association of Australia, or any other body approved by the Director*
- *c) a standard or code published by any other body and approved by the Director*
- *d) a standard or code published specified in Schedule 2*

Our regulatory compliance works program has been developed to facilitate us meeting these regulations.

The volume of compliance work has been determined by having regard to the specific risks associated with each area of non-compliance and the deliverability of the works program. Investment has been prioritised towards those assets that pose the highest safety risks.

This category of investment contains both volumetric activities and discrete projects. For both activities the transmission cost building blocks have been used to develop expenditure forecasts.

A breakdown of AA3 forecast transmission regulatory compliance expenditure by activity (or asset class) is shown in Table 42 and Figure 41.

Table 42: AA3 transmission regulatory compliance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Pole replacement and reinforcement	6.5	7.9	10.2	11.3	11.7	47.6
Protection	1.8	2.1	2.8	3.6	4.5	14.8
Cross-arm replacement	1.2	1.6	2.7	4.0	4.7	14.3
Substation security	0.9	1.4	2.3	3.6	3.9	12.0
Noise mitigation	1.5	1.5	2.1	2.6	2.7	10.4
Substation safety upgrades	0.6	0.6	0.9	1.4	1.5	5.1
Other	1.8	2.2	3.8	5.0	3.8	16.5
Regulatory compliance total	**14.3**	**17.3**	**24.8**	**31.5**	**32.8**	**120.7**

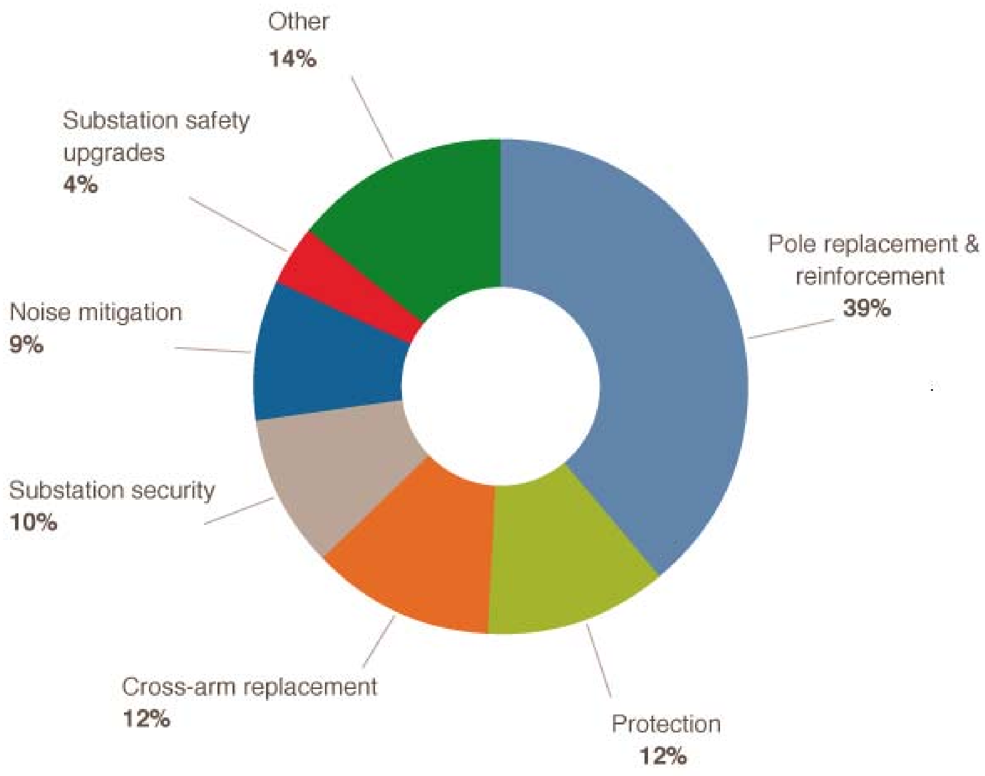

Figure 41: AA3 transmission regulatory compliance expenditure by activity

Each of these activities is discussed in the following sections.

6.4.1.1 Pole replacement and reinforcement

In AA3 we will invest $48 million, 39% of forecast transmission regulatory compliance expenditure, to replace and reinforce poles. This includes a necessary increase in the number of poles replaced and reinforced that will reduce the incidence of unassisted pole failures.

Wood pole failure can have significant consequences to network safety and performance. Poles that fall or lean can result in live conductors coming into contact with other conductors, vegetation, people, buildings or vehicles. There is the risk of electrocution and fire starts (including pole fires) in these circumstances.

The transmission pole replacement and reinforcement program addresses our obligations under the *Electricity (Supply Standards and System Safety) Regulations 2001* to provide a safe environment. This work will ensure that existing transmission pole structures are reinforced to meet *AS/NZS 7000:2010 Overhead Line Design*, our structural requirements and Australian power industry standards and to comply with *Energy Safety Order 01-2009* to improve the management and performance of transmission wood poles.

As outlined in section 2.1.1, the standard industry performance measure for poles is the Transmission Pole Integrity Index (TPII), which reports the number of unassisted pole failures per year, per 10,000 poles. Western Power's TPII was 5.69 for the twelve months to April 2011, more than 12 times higher than the industry average of 0.435. Within the last twelve months the TPII has reversed its downward trend and is now tracking upwards.

We are targeting a step change in the number of poles replaced and reinforced to reduce the unassisted pole failure rate to meet the target of TPII of 1.0 by the end of AA4.

The majority (approximately 68%) of our transmission pole population is wood poles[52]. Pole reinforcement increases the service life of a wood pole by strengthening the pole at ground level (the region most prone to deterioration from decay) and thereby reducing the frequency at which these assets require replacement. Wood pole reinforcement can extend the life of a wood pole by up to 15 years.

Pole replacement is required for poles that no longer provide the required strength to support the overhead network. We have identified a strong correlation between pole age and remaining strength (risk of failure) particularly for poles greater than 30 years of age.

The reinforcement program is targeted at poles less than 35 years of age, with replacement the suitable option for those assets greater than 35 years.

In AA3 we will replace all reinforced transmission wood poles over 45 years old and replace all non-reinforced transmission wood poles over 35 years old. In addition, all reinforced transmission poles that have previously been identified as providing insufficient support (to conductors) will be replaced by the end of June 2017.

6.4.1.2 Protection

In AA3 we will invest $15 million, 12% of forecast transmission regulatory compliance expenditure, on secondary systems, including direct current (DC) systems and fault recording equipment.

[52] Followed by lattice towers (13%), metal poles (11%), Aus poles (wood pole on concrete and steel base) (6%) and concrete poles (2%).

This investment will:

- mitigate the risk of soft tissue and other injuries to our employees through the battery stands safety program, battery charger upgrades and projects to address inadequate clearances on protection panels
- improve compliance with legislative requirements for analysis, rectification and reporting of notifiable events to Energy*Safety* through the installation of fault recorders
- ensure we meet minimum service standard benchmarks through targeted protection upgrades, frame leakage monitoring and installation of system synchronisers

DC systems – battery banks

In AA3 we will invest $4.1 million to upgrade battery cabinets and replace batteries in poor condition and underperforming chargers for 77 DC systems across 37 substations.

DC systems are direct current power supply systems located at terminal and zone substations. They provide a steady supply of power at an appropriate voltage to protection and SCADA equipment which in turn is used to monitor, control and protect primary plant and maintain the integrity of the network. The DC supply system includes a battery bank so that protection and SCADA can continue operating when a fault occurs that interrupts the normal AC supply. Loss of power to the DC supply system in a substation would result in loss of the protection systems, which could lead to network disturbances and asset failure.

The main components of a DC supply system are the battery charger, battery bank, battery paralleling board and structures including the battery room and battery racks. Of this system, the battery bank is the asset which requires the most maintenance and management.

We are upgrading battery banks and chargers to address two key performance and compliance issues:

- batteries stored in ergonomically unfit cabinets, presenting injury risk to the maintenance staff (soft tissue and eye injury)
- batteries at risk of failure from low capacity

The battery cabinets are located in the substation building, sharing space with other equipment such as protection, SCADA and communications. The cabinets are relatively small in size and the space available inside is extremely limited. When technicians perform maintenance that could involve lifting of heavy cell blocks, they have to work crouching in an unstable position with outstretched hands. They are virtually sitting on their knees due to the low position of the batteries (almost at ground level), with their head stuck inside the cabinet. This greatly hampers their ability to use personal protective equipment (such as eye and head protection essential for the assigned tasks), exposing them to the possible risk of electrolyte splashing on their eyes.

We have a population of 516 battery banks regularly inspected and maintained in one, three and six month maintenance cycles. Working in this manner on a large number of batteries is hazardous and tiring.

Fault recorders

In AA3 we will invest $3.6 million to install an additional 16 fault recorders.

Fault recorders installed at strategic locations in the power system provide essential data necessary to predict and analyse major system disturbances (before and after the event). The *Electricity (Supply Standards and System Safety) Regulations 2001* require Western Power to:

- investigate and report on notifiable incidents (section 36):

  (1) If a notifiable incident occurs, the network operator must -

  a) investigate the incident; and

  b) prepare a written report on the outcome of the investigation in a form acceptable to the Director.

  (2) The network operator must give the report to the Director within 20 working days after the day on which the notifiable incident occurred or within such further period as the Director allows.

- report requirements for electrical incidents (section 39):

  (1) As soon as is practicable after each quarter, or such other period as the Director allows, a network operator must give to the Director a report of electrical incidents that have occurred in that quarter or period.

  (2) The report is to be in a summary statistical form acceptable to the Director.

Our ability to comply with this obligation is directly linked to the installation of suitable recording equipment. Information obtained from fault recorders will be used to determine the root cause of major power system incidents and to decide on the remedial action that is necessary to prevent such failures in future.

A fault recorder records instantaneous current and voltage quantities (analogue inputs) and the circuit breaker status (status inputs) of up to ten transmission lines in a substation on a constant basis. The device then uses these basic analogue quantities to derive other relatively complex quantities such as power flow, harmonic content, transient waveforms and frequency variations. It also records events such as circuit breaker and protection relay operations and system anomalies. All these quantities and events are then stored after being time tagged using a global positioning system (GPS) clock signal.

Substation protection compliance

In AA3 we will spend $2.6 million to address the Inadequate working space behind protection panels in early generation relay cabins in substations.

This will be achieved by replacing existing buildings with transportable relay rooms at identified sites using the International Electrotechnical Commission's[53] latest standard for the design of electrical substation automation (IEC61850) technology.

[53] Available at: http://www.iec.ch/

System synchronisers

In AA3 we will invest $1.8 million to install five system synchronisers at strategic locations in the network to enable quick restoration after partial or total blackout.

Restarting the network following a complete unplanned system shutdown is based on the simultaneous restarting of a number of sub-networks, using black start facilities available within them. A critical component of the process of restarting a black system is the ability to reconnect the sub-networks with minimum disturbance. System synchronisers are vital for this process, as they enable operators to control the two sub-networks to bring the voltage and the frequency to within tolerable limits immediately prior to reconnection.

Frame leakage monitoring

In AA3 we will invest $0.7 million to install a monitoring scheme to supervise the frame leakage protection schemes.

The existing frame leakage protection installed at Hay Street, Milligan Street and Piccadilly substation 11 kV indoor switchboards have mal-operated during feeder cable faults when the insulation of the frame with earth has been inadvertently compromised. In 2009/10, there were six instances of mal-operation of frame leakage protection, adding 0.69 minutes to the measure of system minutes interrupted with three events each contributing more than 0.1 system minutes.

We are taking a proactive strategy to prevent mal-operations and ensure transmission system reliability. The monitoring scheme will alert control centre operators instantly when a scheme becomes unstable enabling them to organise corrective action before it causes a major supply interruption.

6.4.1.3 Cross-arm replacement

In AA3 we will invest $14 million, 12% of forecast transmission regulatory compliance expenditure, to replace cross-arms and cross-beams. Transmission cross-arms and cross-beams on poles support overhead electricity conductors at a safe height. They are vital to the safe and reliable provision of covered services.

The program for replacing transmission cross-arms and cross-beams aims to mitigate the hazards associated with unassisted failures of cross-arm and Pi[54] (cross-beam) structures. Unassisted transmission cross-arm and Pi structure failures present a safety risk due to the potential for electrocution from fallen conductors, initiation of ground fires and possible consequential asset and property damage.

The failure of a Pi structure in 2005 that resulted in a bushfire triggered a structural assessment of the current population of Western Power's Pi structures, which was completed in 2009. The assessment determined that the standard design for this type of structure was not sufficient in cases where these structures support span lengths greater than 350 m. We are upgrading the 138 transmission Pi structures in this category from the existing wooden cross-beams to a steel cross-beam. In addition, an extra pole will be installed where span lengths exceed 350 m.

In AA3 we will continue with the program that commenced in AA2 and replace 863 cross-arms and 132 cross-beams to reduce the risk of failure of these structures.

[54] A 'Pi' structure is an overhead conductor support system which incorporates two poles and a cross-beam to accommodate the demands on long spans of conductor between supporting assets.

6.4.1.4 Substation security

In AA3 we will invest $12 million, 10% of forecast transmission regulatory compliance expenditure, to improve substation security. This investment addresses the increased number of unauthorised entries to our substations and the significant public safety risk this poses.

Asset security is recognised throughout the Australian electricity industry as a significant business risk. Unauthorised entry to substations is an ongoing issue. Safety of the public and our staff is a major concern, with supply security also at risk. Other security issues include theft of materials and construction equipment, damage to plant and vandalism of fences and buildings.

Evidence of ongoing unauthorised access to the 152 terminal and zone substations over the past 10 year period is summarised in Table 43. This shows an increase in the reported incident rate over time. The actual incident rate is likely to be much greater that the reported incident rate. Substation sites are unmanned, generally have no electronic surveillance[55] and have no security lighting. Unless significant damage is caused during the unauthorised access, the incident may not be detected and hence not reported. 95% of the incidents are at sites with chain-mesh boundary fencing, which can be easily climbed without causing damage.

Table 43: Reported incidents of unauthorised access

Period	Vandalism	Theft	Injury	Total
2000/01 – 04/05	231	21	2	254
Average per annum	46.2	4.2	0.4	51
2005/06 – 09/10	323	37	0	360
Average per annum	64.6	7.4	0	72

Adult intruders at Midland Junction and Rivervale zone substations were electrocuted and substation blackouts resulted. These two substations have since had their perimeter fences significantly improved from chain-mesh to 3m high palisade (Midland Junction) and masonry with palisade topping (Rivervale). Two other incidents of unauthorised access (involving interference to control equipment) have also resulted in transmission lines inadvertently being switched off and a zone substation blacking out.

In order to comply with the *Electricity Act 1945* and *Electricity (Supply Standards and System Safety) Regulations 2001*, we have had regard to both industry standards and our own internal standards to assess the appropriate standard for substation security. These include the Energy Networks Association's (ENA) *Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure*[56] and related Western Power standards and security risk assessments. The ENA guidelines have recently been enhanced due to the threat of terrorism and the increased number of incidents involving unauthorised entry around Australia, some of which have resulted in fatalities.

Approximately 150 terminal and zone substations have been determined to require partial or complete fencing and security upgrade work including physical barriers, signage, lighting and active security monitoring. Site selection or prioritisation is based on vulnerability and condition assessments as well as maintenance cost history and unauthorised access incident history.

[55] Rockingham S/S, Medina S/S, Northern Terminal, Southern Terminal and Neerabup Terminal have fence alarms

[56] ENA DOC 015 -2006, available at: http://www.ena.asn.au/?page_id=4935

In AA3 we will improve security at 22 substations, compared with 4 in AA2. A further 122 substations will be addressed during future access arrangement periods.

6.4.1.5 Noise mitigation

In AA3 we will invest $10 million, 9% of forecast transmission regulatory compliance expenditure, to comply with noise regulations at substations. This is a step increase on the previous five year period where many of the early years of the program were spent undertaking noise investigations and determining workable technical solutions to reduce noise levels.

Regulation 17(7) of the *Environmental Protection (Noise) Regulations 1997*[57] specifies a maximum acceptable noise output that can be emitted by our assets. We applied to the Minister for the Environment and received approval for a variation to Regulation 17. The Regulation 17 variation requires us to implement a program of noise reduction, where noise levels were exceeded by more than 5 dBA, at a number of designated sites. We are yet to complete the requirements of the Regulation 17 variation.

We have chosen to defer or reschedule works where there is the opportunity to combine other compliance related work and efficiently minimise mobilisation and demobilisation costs.

Sites at risk of breaching noise regulations are investigated prior to commencing design. We then adopt the following criteria to prioritise substations for mitigation:

- high night time noise levels greater than Regulation 17 variation
- significant number of affected residences
- no future site development is proposed
- community involvement in the Regulation 17 process, through complaints or other contact with us
- noise mitigation costs assessed as being reasonable and practical given the expected benefit to the local community

In AA3 we will conduct noise mitigation works at 9 substation sites: Arkana, Belmont, Byford, Collier, Forrest Avenue, Myaree, North Beach, Sawyers Valley and Wundowie and investigate 13 substations at risk of breaching noise regulations. At the end of the AA3 period, the noise mitigation works at two sites will need to be completed, a further10 sites will require compliance works to meet the noise regulations and 15 sites will require assessment to determine their level of compliance with the noise regulations. Mitigation works at these remaining transmission substation sites will be included in future access arrangement periods.

6.4.1.6 Substation safety upgrades

In AA3 we will invest $5 million, 4% of forecast transmission regulatory compliance expenditure, on substation safety upgrades. This is an increase on the previous five year period and reflects the increased number of substations to be addressed during AA3.

We have an ongoing program to upgrade the safety of substations as they expose our employees, contractors and members of the public to injury, disability or death. The current substation safety upgrade program began following the electrocution of an engineer in Coolgardie when inspecting the zone substation in 1998. Following this, we made immediate recommendations for changes to be made on substation equipment and access. The scope of work was extended to cover public, operation and maintenance safety.

[57] Available at: http://www.melvillecity.com.au/community/health/health-legislation/environmental-protection-noise-regulations-1997.pdf

All substation sites were inspected under the original inspection program and 1,997 items were found to be non-compliant to standards or posed a safety issue. These hazards were categorized from priority 1 to 3, with priority 1 hazards the most significant and priority 3 hazards the least significant. Priority 1 and some priority 2 hazards have been addressed at 42 substation sites since 2000/01, as shown in Figure 42.

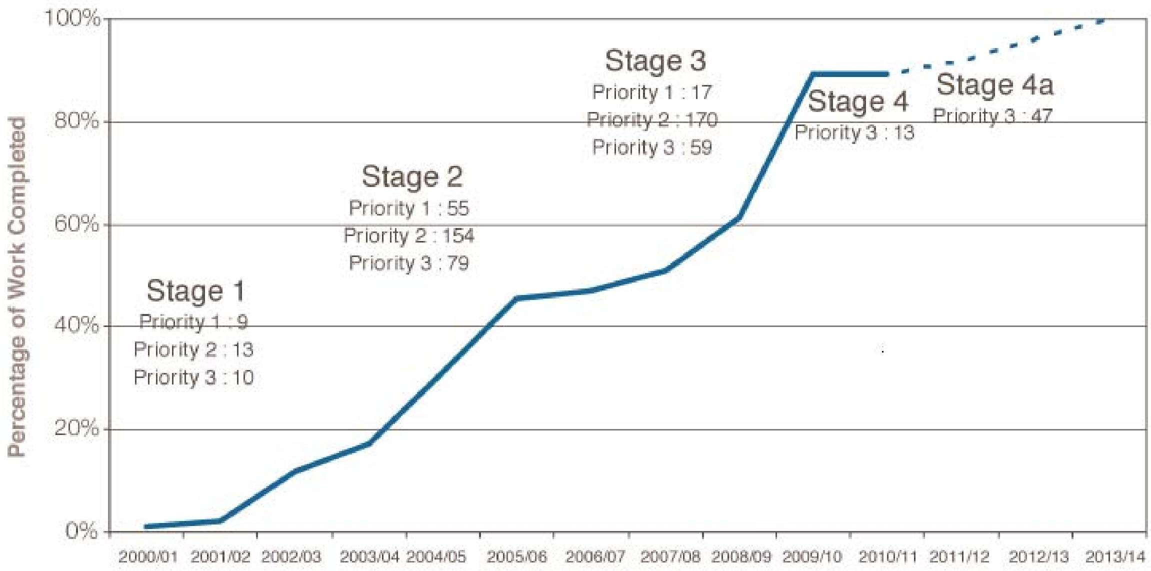

Figure 42: Transmission substation safety upgrades progress

In AA3 we will address the remaining priority 2 and all priority 3 hazards. This will involve correcting items at 73 substations including:

- Priority 2: non-conformance with Australian Standards such as HV equipment clearances unrestricted vehicle access (enabling vehicles to approach close to high voltage equipment) inadequate work safety clearances unshrouded live 415/240V terminals in AC Boards, battery chargers, control cubicles and relay racks; and dangerous obstructions such as trip hazards and low overhanging structures
- Priority 3: non-conformance with Australian Standards such as the absence of isolator operator earth mats earth mats not being supported adequately on foundations or on cable trenches incorrect earthing inadequate lighting inadequate lightning protection ground clearance infringements caused by brick steps leading to voltage circuit breaker mechanism boxes uneven or eroded road surfaces or absence of blue metal and broken culverts

The program is designed to ensure compliance with:

- *Electricity (Supply Standards and System Safety) Regulations 2001* to provide a safe environment
- *Australian Standard*[58] *AS2067-2008 Substations and high voltage installations exceeding 1 kVAC*
- our duty of care for the safety of our employees, contractors and the public

58 Available at: http://www.standards.org.au/

6.4.1.7 Other

The following activities are individually less than $5 million per program over the AA3 period or below 4% of forecast transmission regulatory compliance expenditure.

- Non-complying stays ($4.7 million) – a line survey in 2006 found that 1,467 residential and 1,477 country stays were not in compliance with ENA C (b)-2006, Section 12: Earthing and Insulation of Stay wires. The stay installations nominated for replacement are substandard. In the case of failure they may come into contact with HV conductors and potentially expose the area around the structure to arcing during contact with the ground leading to bush, property or fires and other public safety hazards. In AA3 we will replace the remaining 1,504 non-complying stays.
- Asbestos removal ($3.9 million) – there are 140 substation sites with asbestos contaminated material. Of these there are 96 substation sites known to contain asbestos in the form of asbestos cement building products, resinous material containing asbestos, debris and insulation materials. We progressively remove and replace the asbestos material with 'safe' building or other appropriate material to ensure compliance with the *Code of Practice for the Management and Control of Asbestos in the Workplace (NOHSC: 2018 (2005)*. In AA3 we will remove asbestos at 22 substations.
- Transformer bunding ($2.5 million) – we are installing or sealing bunds of transmission transformers at brownfield substation sites to address our legislative environmental compliance obligations, including requirements of the *Contaminated Sites Act 2003*, *Environmental Protection (Unauthorised Discharge) Regulations 2004* and *Australian Standard AS2067 – 2008 Substations and high voltage installations exceeding 1 kV AC*. There are approximately 340 transmission substation transformers installed at about 170 transmission substation sites. The sealing of these bunds will considerably reduce the potential of soil and ground water contamination. We will coordinate this work where we can across the noise mitigation work, installation of firewalls and transformer asset replacement activities. In AA3 we will undertake bunding works at 20 sites.
- Automatic disconnectors ($1.9 million) – as a result of near miss safety incidents of busbar disconnectors explosively failing whilst being manually operated, we are retrofitting load make and break 22 kV busbar disconnectors in all metropolitan substations. Works in AA3 is the second and final stage of the project to address manually operated 22 kV busbar switch disconnectors being called upon to operate outside of their rating capability. We will replace 66 units in the AA3 period.
- Substation earthing ($1.7 million) – hazard reports issued on a number of substation sites in recent years have raised concern about the quality of the earthing in respect to earth potential rise (EPR) risks to employees and the public. To address this public safety risk, we are introducing routine testing of substation earthing and remediation for all sites found to be non-complaint. We will investigate 170 substation sites to confirm compliance to current earthing standards or schedule upgrades as required.

7 Distribution capital investment

Distribution capital investment comprises work for expanding the capacity of the Western Power Network and replacing and reinforcing, where necessary, the existing assets.

In AA3 we will invest $3.581 billion on distribution capital projects and programs necessary to connect new customers and ensure the continuous provision of covered services for existing customers on the Western Power Network. Of this, $744 million is forecast to be contributed by individual customers for connection or other services.

As set out in chapter 8 of the AAI, our distribution capital expenditure is segregated into the following high level categories: growth, asset replacement and renewal, improvement in service and compliance. The detailed and high level categories of expenditure are shown in Table 44.

Table 44: AA3 distribution expenditure ($ million real at 30 June 2012)

AA3 expenditure by category	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of total (gross)
Customer Access	207.9	209.0	217.3	220.5	228.3	1,083.0	30.2%
Capacity Expansion	66.3	75.2	88.3	90.0	94.1	413.9	11.6%
Gifted Assets	64.3	64.3	64.3	64.3	64.3	321.3	9.0%
Growth (gross)	338.5	348.5	369.9	374.8	386.7	1,818.3	50.8%
less capital contributions	137.0	137.4	140.3	141.4	144.2	700.4	19.6%
Growth (net)	**201.4**	**211.1**	**229.6**	**233.3**	**242.5**	**1,117.9**	**31.2%**
Asset replacement	160.4	172.1	181.4	194.8	210.7	919.3	25.7%
Metering	15.4	48.6	48.5	45.0	18.3	175.8	4.9%
Smart Grid	2.6	24.6	27.4	20.9	16.0	91.4	2.6%
SUPP	39.2	18.9	-	-	-	58.1	1.6%
Asset replacement and renewal (gross)	217.5	264.3	257.3	260.6	244.9	1,244.6	34.8%
less capital contributions	29.4	14.2	-	-	-	43.6	1.2%
Asset replacement and renewal (net)	**188.1**	**250.1**	**257.3**	**260.6**	**244.9**	**1,201.1**	**33.5%**
Compliance	**100.7**	**107.3**	**110.4**	**79.3**	**87.6**	**485.3**	**13.6%**
SCADA and communications	4.9	6.0	7.1	4.1	7.5	29.6	0.8%
Reliability driven	0.6	0.6	0.7	0.7	0.7	3.3	0.1%
Improvement in Service	**5.5**	**6.6**	**7.7**	**4.8**	**8.2**	**32.9**	**0.9%**
Distribution total (gross)	**662.3**	**726.7**	**745.3**	**719.4**	**727.4**	**3,581.1**	**100%**
less capital contributions	166.4	151.6	140.3	141.4	144.2	744.0	20.8%
Distribution capital expenditure to be recovered from reference tariffs	**495.9**	**575.1**	**605.0**	**578.0**	**583.2**	**2,837.2**	**79%**

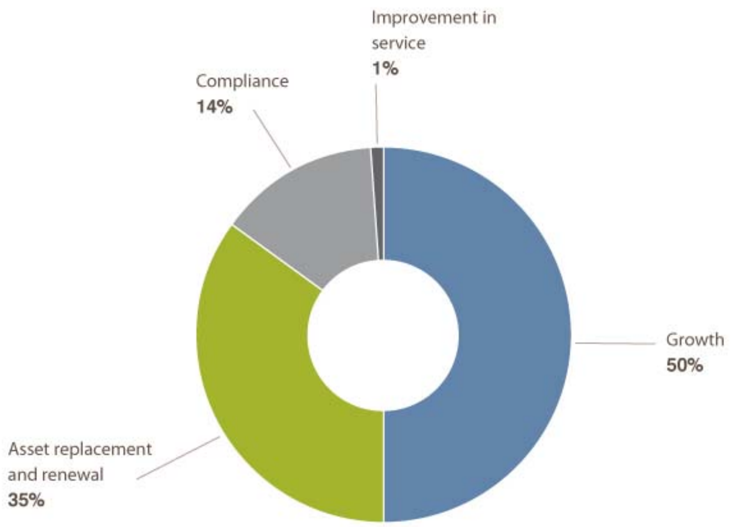

Figure 43: AA3 distribution capital expenditure by reason

7.1 Growth

In AA3 we will invest $1.818 billion, 50% of forecast distribution capital expenditure, to accommodate the 51%[59] increase in maximum peak demand and 11.2% increase in customer numbers. Of this, individual customers will contribute $700 million for connection or other services.

The distribution growth category of work includes:

- customer access – driven by the requirements of individual customers. This work provides the connection between the distribution-connected customers' premises and the network and is usually funded by the individual customer via a capital contribution and future incremental tariff revenue
- capacity expansion – driven by our legislative obligations, the requirements of the Technical Rules and planning criteria, with the main trigger for investment being forecast load growth (see chapter 6 of the AAI). This work typically involves expanding network capacity by installing new infrastructure or reinforcing existing assets on the distribution network
- gifted assets – network assets built by developers (residential and commercial subdivisions), which are then transferred to Western Power to own and operate. Gifted assets are not included as part of Western Power's AA3 forecast expenditure. However, given Western Power incurs tax on gifted assets and must maintain and operate these assets, they are discussed in this report for completeness

[59] See chapter 6 of the AAI for forecast maximum demand and customer numbers for the AA3 period. The % increase represents the total change from 2011/12 to 2016/17.

7.1.1 Customer access

In AA3 we will invest $1.083 billion, 30% of forecast distribution capital expenditure, on distribution customer access works to provide our customers with access to the distribution network. Of this, customers who will benefit from the investment will contribute $379 million or 35%.

Distribution customer access expenditure includes all work associated with the connection of customer loads or generators or the relocation of distribution assets on the Western Power Network at the request of an external party.

Distribution customer access works are, to a large extent, non-discretionary and include many diverse activities ranging from small residential connections (pole to pillar) to small subdivisions (of two to four lots) and network extensions to cater for connection of major distribution-connected loads. This category of investment generally includes high volumes of low cost works. Thus, historical expenditure tends to be a good indicator of future investment as shown in Figure 44.

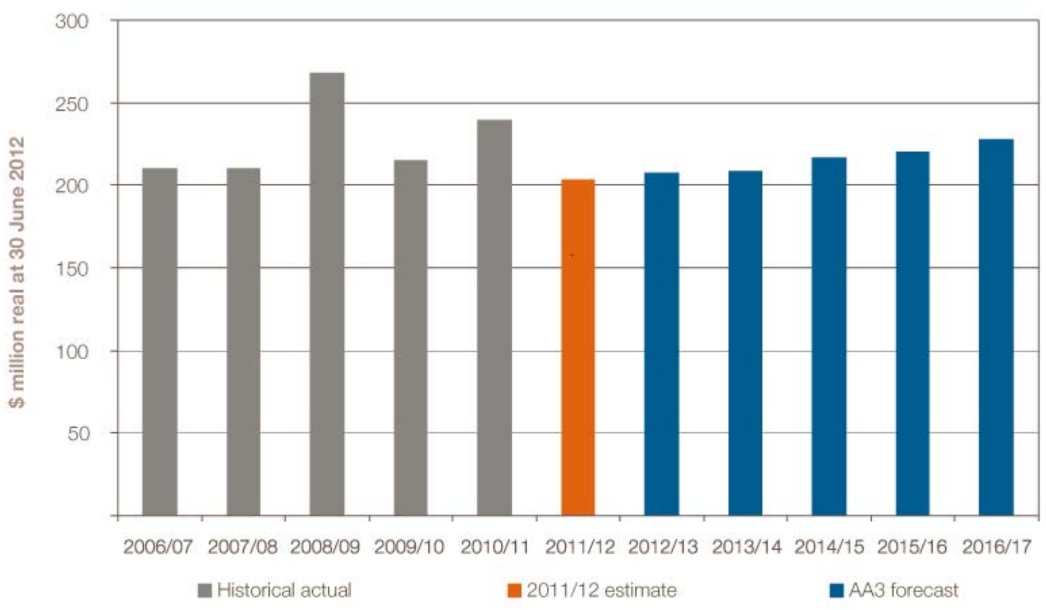

Figure 44: Distribution customer access historical and forecast capital expenditure

We have used historical trends to forecast this investment, adjusting as necessary for:

- the current volume of customer applications
- information on projects that are currently scheduled for construction
- forecasts of economic growth

New facilities investment test

New facilities investments in distribution customer access projects are only undertaken where section 6.52(b) (i) of the Access Code is met or the connecting customer contributes that part of the investment that does not meet section 6.52(b). Section 6.52(b) (i) of the Access Code requires that *the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment*.

The connecting customer contributes that part of the investment that does not meet the incremental revenue test, in accordance with the *Contributions Policy* developed under sections 5.12 to 5.17 of the Access Code.

Under section 3 of the contributions policy:

> *A contribution with respect to covered services sought by an applicant must not exceed the amount that would be required by a prudent service provider acting efficiently, in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of providing the covered services.*

AA3 distribution customer access contributions have been forecast in line with historical ratios of contributions to expenditure, as outlined in chapter 8 of the AAI. In the Authority's 'Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network' it was noted:

> *On the basis of the ratios of contributions to levels of customer driven investment, the Authority accepts that the forecast of contributions is reasonable and the residual values of investment may reasonably be expected to satisfy the second part of the new facilities investment test under section 6.52(b) of the Access Code.*

In the AA3 period, we are introducing a Distribution Low Voltage Charging Model (see section 20.2.2 of the AAI). This charging model is designed to move away from the 'user pays' principle for a specific segment of customers and adopts a charging methodology based on a set of standard charges which apply to the requested customer load. This model will be introduced as an amendment to the *Contributions Policy*, with contributions calculated under this model affecting between 800 to 1,000 distribution-connected customers per annum. These are generally low value projects accounting for less than 4% of total new connections per annum and are therefore not expected to materially change the forecast ratio of contributions to expenditure.

AA3 distribution customer access expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. We consider that the Access Code requirements are best satisfied if growth-related investment is based on historical expenditure, adjusted for identifiable drivers comprising the forecast number of new connections and the forecast market movement in the price of labour and materials. This ensures that prices are not increased above levels that have been sufficient to meet customer's needs in the past. The investment adjustment mechanism also ensures that we are able to invest efficiently in customer driven capital expenditure if necessary.

Relocation of existing assets generally does not satisfy section 6.52(b) of the Access Code and hence contributions are generally sought from the party requesting the relocation for the full amount of the efficient investment in these works.

Appendix 8 of the Access Code applies to relocations of existing network assets. The full amount is efficient because:

A contribution for Appendix 8 work (other than a flat fee under clauses A8.5 and A8.17) must not exceed the forecast cost that would be forecast to be incurred for the work by a service provider efficiently minimising costs[60]

[60] Section A8.3 of the Access Code.

REGULATORY OBLIGATIONS

The Access Code places obligations on Western Power to connect customers to its network. Section 2.7 of the Access Codes requires that:

A service provider for a covered network must use all reasonable endeavours to accommodate an applicant's:

- *a) requirement to obtain covered services; and*
- *b) requirements in connection with the negotiation of an access contract*

Further, section 2.8 of the Access Codes states that:

Without limiting section 2.7, a service provider must:

- *a) comply with the access arrangement for its covered network and must expeditiously and diligently process access applications; and*
- *b) negotiate in good faith with an applicant regarding the terms for an access contract; and*
- *c) to the extent reasonably practicable in accordance with good electricity industry practice, permit an applicant to acquire a covered service containing only those elements of the covered service which the applicant wishes to acquire; and*
- *d) to the extent reasonably practicable, specify a separate tariff for an element of a covered service if requested by an applicant, which tariff must be determined in accordance with sections 10.23 and 10.24; and*
- *e) when forming a view as to whether all or part of any proposed new facilities investment meets the test in section 6.51A, form that view as a reasonable and prudent person.*

Access applications are processed in accordance with the applications and queuing policy developed under sections 5.7 to 5.11 of the Access Code.

We also have an obligation to connect certain classes of customers within specified timeframes as outlined in section 4 to 6 of the *Electricity Industry (Obligation to Connect) Regulations 2005**:

4. Obligation to attach or connect premises

If premises are not attached to a distribution system and —

- *a) retailer seeks to make arrangements with the distributor for the premises to be attached or connected;*
- *b) customer applies to the distributor for the premises to be attached; or*
- *c) customer who will not use more than 50 MWh per annum at the premises applies to the distributor, before 1 January 2006, for the premises to be connected, the distributor must, in the circumstances described in regulation 5(1), attach or connect the premises to the system, as the case requires*

5. Details of obligation to attach or connect

- *(1) An obligation under regulation 4 to attach or connect premises arises only if —*
  - *(a) the distribution system would not need to be extended by more than 100 metres to enable the premises to be attached or connected to the system; and*
  - *(b) each requirement, if any that the distributor imposes under sub regulation (2) or (3) has been satisfied.*
- *(2) Before the end of the second complete business day after arrangements are sought to be made, or an application is made, under regulation 4 for premises to be attached to a distribution system, the distributor may impose any of the requirements described in sub regulation (4) (a) or (b).*
- *(3) Before the end of the second complete business day after arrangements are sought to be made, or an application is made, under regulation 4 for premises to be connected to a distribution system, the distributor may impose any of the requirements described in sub regulation (4).*

6. Time for complying with obligation

- *(1) If the distributor is obliged under regulation 4 to attach or connect premises to a distribution system, it is required to do so before the time limit imposed by sub regulation (2).*
- *(2) The time limit under this sub regulation is —*
  - *(a) the end of the 20th business day after the time when the obligation arises; or*
  - *(b) any later time to which the customer agrees in writing.*
- *(3) If, during any of the time that this regulation gives the distributor for complying with the obligation, any written law prevents the distributor from complying, sub regulation (2) applies as if the obligation arises when the written law ceases to prevent the distributor from complying.*

In addition, network extensions, new and modified connections must comply with the *Electricity (Licensing) Regulations 1991**, which require electrical work to be carried out in accordance with certain requirements including but not limited to:

- the *wiring rules* (AS/NZS 3000)
- the *Western Australian Electrical Requirements* (WAER)*

Full details of charging policies and customer contribution calculation for connections to Distribution Network can be found in the *Distribution Connection Manual* which is published on Western Power's website.

We are not obliged to relocate our assets when requested to do so by an outside party. However, we will assist other parties by relocating assets at their request on a fee-for service basis. This service is provided with the following conditions:

- the proponent funds the total actual cost for us to undertake the works
- the relocation will not disadvantage any third party

* Available at: http://www.austlii.edu.au/au/legis/wa/consol_reg/er1991331/

* Available at: http://www.commerce.wa.gov.au/energysafety/PDF/Publications/WA_Electrical_Requirements.pdf

A breakdown of AA3 forecast distribution customer access expenditure by activity is shown in Table 45 and Figure 45.

Table 45: Distribution customer access activities ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Network extension	159.2	160.2	167.8	170.4	176.5	834.1
Connection	21.6	21.5	21.5	21.5	22.3	108.3
Subdivision	18.9	19.1	19.3	19.5	20.2	97.0
Relocation	8.2	8.2	8.7	9.1	9.4	43.5
Customer access total	**207.9**	**209.0**	**217.3**	**220.5**	**228.3**	**1,083.0**
less capital contributions	72.8	73.1	76.1	77.2	79.9	379.1
Net customer access total	**135.1**	**135.8**	**141.3**	**143.3**	**148.4**	**704.0**

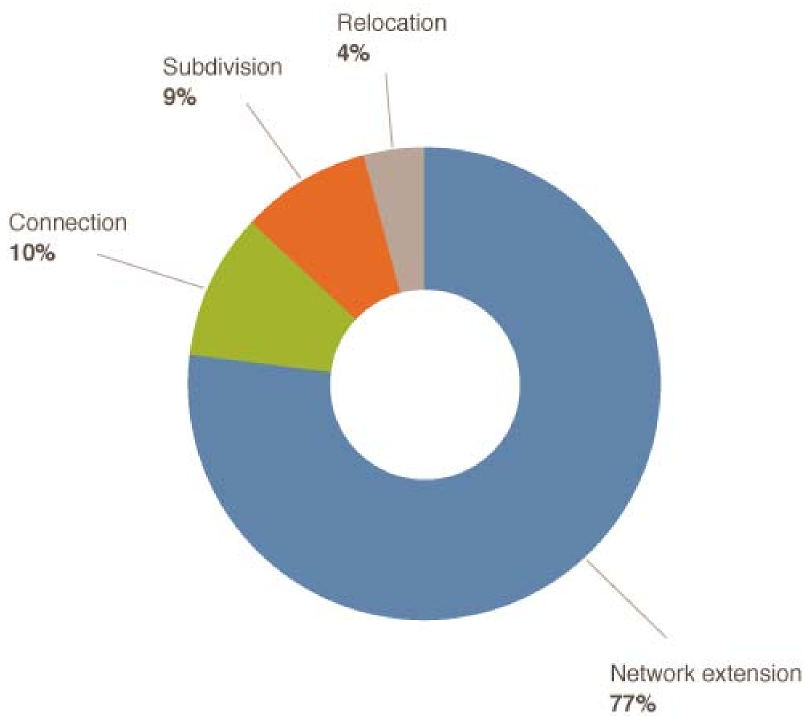

Figure 45: AA3 distribution customer access expenditure by activity

In February 2011, we published the Western Australian Distribution Connections Manual in conjunction with Horizon Power. This manual, which is available on our website[61], is a comprehensive guide to residential and industrial customers as to the applicable roles,

[61] Available at: http://www.westernpower.com.au/documents/WA_Distribution_Connections_Manual.pdf

responsibilities, processes and minimum technical specifications required to facilitate customer connections.

The following sections include a brief description of customer access activities. Further details regarding the activities and charging policies applicable to each type of customer connection, modification or asset relocation request are outlined in the Western Australian Distribution Connections Manual.

7.1.1.1 Network extension

In AA3 we will invest $834 million, 77% of forecast customer access expenditure, to extend the network to cater for customers connecting to the distribution network. This includes discrete projects to cater for new connection points as well as modifications to existing connection points.

We are required to *expeditiously and diligently process access applications*[62] using all reasonable endeavours to accommodate an applicant's requirement to obtain covered services. An applicant's requirement to obtain covered services may require the network to be extended to the proposed point of connection or to accommodate the additional capacity requirements requested by the customer. The size of the network extension, and hence costs, for this category of work are influenced by:

- the distance to the nearest point of connection on the distribution network
- the available capacity on the network at the proposed connection point

Network extensions are mainly required for industrial distribution-connected customers. Capital contributions are calculated for these discrete projects under the *Contributions Policy* using our standard 'capital contribution calculator'. Where a customer requests connection in rural areas of the distribution network or connection to the low voltage distribution network, then the Headwork's Charging or Low Voltage Charging Models may apply (see section 16.4 of the AAI).

7.1.1.2 Connection

In AA3 we will invest $108 million, 10% of forecast customer access expenditure, to provide new or modified connection points (such as pole to pillar) to residential and business customers (including unmetered supplies such as streetlights).

This includes those works where *the distribution system would not need to be extended by more than 100 metres to enable the premises to be attached or connected to the system*[63]. When significant network augmentation is required to accommodate the new or modified connection point, these works fall under network extensions.

These works are influenced by the number of new customers. The growth rate or number of new customers per annum has been reasonably consistent during AA1 and AA2 and is forecast to continue to be consistent during the AA3.

We anticipate that the State Underground Power Program and requirement for all new subdivisions to install underground pillars will contribute to a decreasing rate of the number of pole to pillar requests in future access arrangement periods.

[62] Section 2.8 of the Access Code.
[63] Electricity Industry (Obligations to Connect) Regulations 2005, regulation 5(1) (a)

7.1.1.3 Subdivision

In AA3 we will invest $97 million, 9% of forecast customer access expenditure, to provide new or modified connection points (such as pole to pillar) to residential and small development subdivisions. This includes the provision of connection points for customers (residential and commercial) as well as the associated reticulation of the distribution network through the subdivision.

In addition to residential subdivisions, this program also includes the design and installation of electrical infrastructure to support the Western Australian Planning Commission state development activities.

Works to extend the distribution network and connect subdivisions greater than four lots are typically undertaken by third parties and gifted to Western Power, as discussed in section 7.1.3.

7.1.1.4 Relocation

In AA3 we will invest $44 million, 4% of forecast customer access expenditure, to relocate distribution assets at the request of a customer. We relocate distribution assets (66 kV or above) to accommodate the needs of external parties.

Relocation of existing distribution assets is largely triggered by local councils and other Government departments through the Western Australian Planning Commission. Works include ‘black spot’ Government programs.

The relocation of equipment may include infrastructure such as overhead lines, transformers, poles, cables, stay wires and service pillars. The cost to relocate the equipment can vary significantly depending on the nature of the infrastructure to be moved and its operational voltage.

7.1.2 Capacity expansion

In AA3 we will invest $414 million, 12% of forecast distribution capital expenditure, to expand capacity in the distribution system.

Capacity expansion works maintain supply and expand the existing Western Power Network to meet the growing demand for energy. This is achieved by constructing new assets or upgrading existing substation assets, distribution feeders and distribution transformers. This ensures our ongoing ability to support the growth of existing residential and small business loads.

Whilst transmission capacity expansion comprises a relatively small number of large projects, distribution capacity expansion generally comprises a relatively large number of small projects and hence investment trends tend to be more consistent over time. In addition, in AA3 we have a small number of large distribution projects associated with installing a pit and duct cable system in the CBD and the distribution works associated with the new zone substation in the CBD area.

Deferral of investment during the AA2 period led too much of the reserve capacity in the network being used to connect new customers and facilitate growth. In AA3 we will need to increase investment to significantly reduce the risk of long-duration outages (> 5 hours) caused by the high utilisation rates on our feeders. This investment will reduce the utilisation rate in line with good electricity industry practice adopted by most other networks businesses in the eastern states[64].

[64] The level of interconnection of distribution feeders in the Perth metropolitan area allows a target utilisation of 80% which is higher than the national benchmark level of 66%.

Figure 46 shows our historical expenditure including the impact of constrained investment levels during AA2. In AA3 our distribution capacity expansion expenditure will:

- meet an increased in the system peak demand from 3,581 MW in 2010/11 to 5,061 MW by the end of AA3
- reduce the number of metropolitan distribution feeders with a utilisation rate above 80% from 236 to 0 by the end of AA3, thereby significantly reducing the number of customers at risk from long-duration outages
- reduce the number of country customers at risk of potential equipment damage due to voltage constrained feeders by 70% by the end of AA3

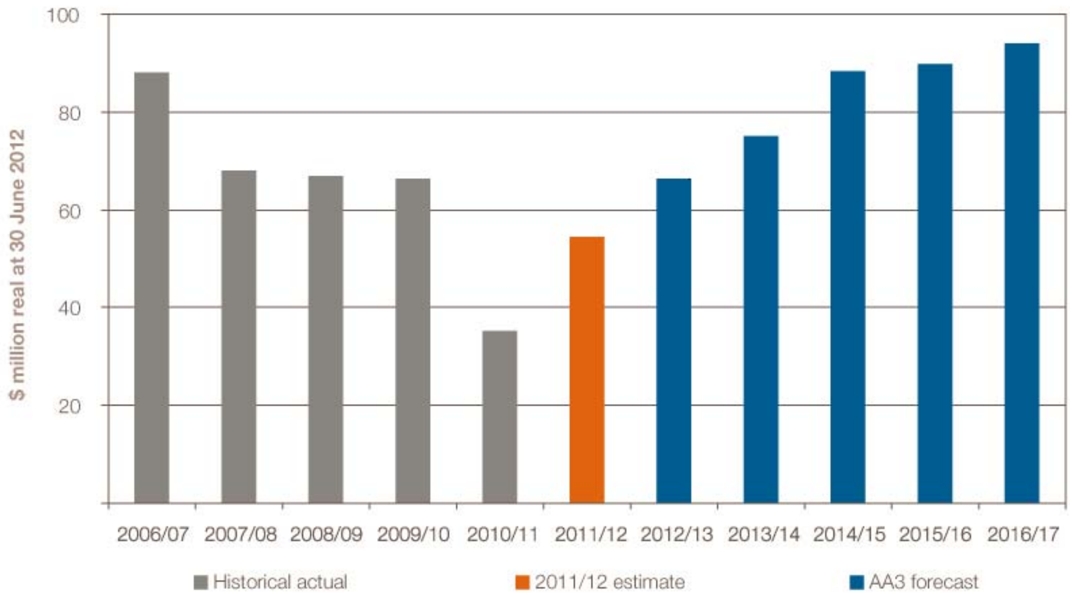

Figure 46: Distribution capacity expansion historical and forecast capital expenditure

The specific projects to expand capacity in the distribution system are identified through the network development planning process, which is discussed in section 2.2. The network planning process assesses:

- the distribution projects required to support a transmission capacity expansion project
- the utilisation of each distribution feeder to determine whether there is sufficient spare capacity to allow load to be transferred between different parts of the network and provide the level of redundancy required in the *Technical Rules*
- the loading on each distribution transformer and low voltage cable to determine whether they will be overloaded
- whether the fault level rating of the distribution feeders will be exceeded
- whether the protection relays will be able to detect all faults on the network
- whether the distribution voltage level complies with the *Technical Rules*

- whether the level of load imbalance on distribution feeders complies with the *Technical Rules*

New facilities investment test

New facilities investments in distribution capacity expansion are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 distribution capacity expansion expenditure has been assessed as meeting section 6.52(b) (iii) of the Access Code. The network development plan and distribution network planning guidelines indicate the extent to which contracted covered services cannot be provided if not for the investment.

AA3 distribution capacity expansion expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. In addition, we efficiently minimise costs by ensuring that more costly network augmentations are deferred when non-network alternatives, such as procurement of generation or demand side management, represent the lowest sustainable cost option. Our distribution capacity expansion program ensures we install new facilities with sufficient capacity to meet the forecast sales, directly informed by our independently verified demand forecasts.

REGULATORY OBLIGATIONS

We must plan the distribution network so that there is sufficient capacity to distribute power from zone substations to individual customers, and that the requirements in the *Technical Rules* are met.

Section 12.4 of the Access Code states that we must comply with the *Technical Rules*. Appendix 6 of the Access Code sets out the matters that must be addressed by the *Technical Rules*. These matters include the criteria for planning the network, as outlined in section 0 of this document.

The sections of the *Technical Rules* that are particularly relevant are summarised below:

- section 2.2.2 – *Except as a consequence of a non-credible contingency event, the minimum steady state voltage on the transmission system and those parts of the distribution system operating at voltages of 6 kV and above must be 90% of nominal voltage and the maximum steady state voltage must be 110% of nominal voltage. For those parts of the distribution system operating below voltages of 6 kV, the steady state voltage must be within:*
  1. *± 6% of the nominal voltage during normal operating state,*
  2. *± 8% of the nominal voltage during maintenance conditions,*
  3. *±10% of the nominal voltage during emergency conditions*
- section 2.3.9 – *The Network Service Provider must monitor the performance of the power system on an ongoing basis and ensure that the transmission and distribution systems are augmented as necessary so that the power system performance standards specified in clause 2.2 continue to be met irrespective of changes in the magnitude and location of connected loads and generating units*
- section 2.5 – specifies the planning criteria that applies to *distribution systems and not to connection assets* including the N-0, N-1, N-1-1 criterion, CBD planning criterion and zone substation criterion. Specifically this includes:
  - section 2.5.4.3(b)(2) – the *distribution feeder must be designed so that, if an unplanned single feeder outage occurs due to an equipment failure within the zone substation or a failure of the exit cable, the load on the faulted feeder can be transferred to other feeders with the following provisions:*

    (A) no other feeder will pick up more than 50% of the peak load from the faulted distribution feeder unless capacity has been specifically reserved to provide back-up
  - section 2.5.6 – *The calculated maximum fault level at any point in the transmission and distribution system must not exceed 95% of the equipment fault rating at that point*.
- section 2.6(a) – *All distribution systems must be designed to supply the maximum reasonably foreseeable load anticipated for the area served. The maximum reasonably foreseeable load must be determined by estimating the peak load of the area after it has been fully developed, taking into account restrictions on land use and assuming current electricity consumption patterns.*
- section 2.8 – *Extension and reinforcements to the distribution system must be designed and constructed in accordance with a distribution system concept plan for the area. The installation must conform to the concept plan and use conductors or cables that are:*

  b) configured with the objective of minimising the life time cost to the community; and

  c) of a standard carrier size that is equal to or greater than that required for the reasonably foreseeable load'
- section 2.9.1(a). – *All primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted equipment item is automatically removed from service by the operation of circuit breakers or fuses. Protection systems must be designed and their settings coordinated so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in power transfer capability or in the level of service provided to Users is minimised*.

REGULATORY TEST

The regulatory test requirements under section 9.2 of the Access Code are discussed in section 6.1.1 of this document. For distribution projects, a major augmentation is defined as a new facilities investment for assets which exceeds $10.9 million (CPI adjusted for 2010/11); where the network assets comprising the augmentation are, or are to be, part of the distribution system.

In AA3 we will ensure that the Authority is satisfied that the regulatory test is met before proceeding with any other major augmentation that exceeds the threshold.

A breakdown of AA3 forecast distribution capacity expansion expenditure by activity is shown in Table 46 and Figure 47.

Table 46: AA3 distribution capacity expansion expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
HV distribution driven	42.0	46.5	54.2	46.3	56.2	245.3
Transmission driven	7.5	10.7	14.2	17.0	9.7	59.2
Overloaded transformers and LV cables	11.2	11.3	11.5	11.7	12.1	57.7
Fault levels and protection	5.6	6.7	8.4	15.0	16.1	51.8
Capacity expansion total	**66.3**	**75.2**	**88.3**	**90.0**	**94.1**	**413.9**

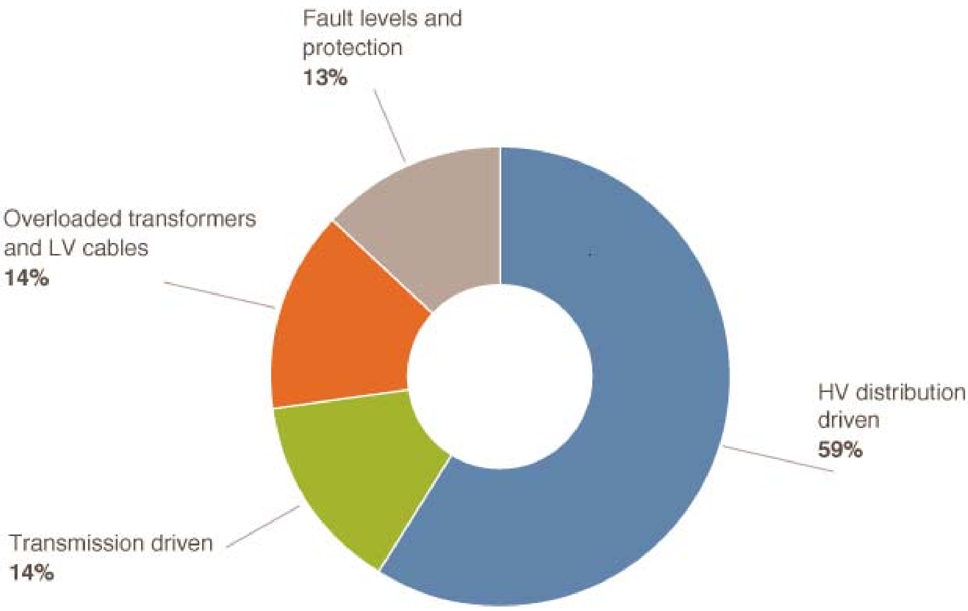

Figure 47: AA3 distribution capacity expansion expenditure by activity

Each of these activities is discussed in the following sections.

7.1.2.1 HV distribution driven

In AA3 we will invest $245 million, 59% of forecast distribution capacity expansion expenditure, on projects to ensure that the following requirements in the *Technical Rules* are met:

- the distribution feeders do not exceed optimal utilisation levels
- the voltage is within the required limits
- the load on the network is balanced across the three phases
- there is the required level of redundancy

Addressing the utilisation rate of distribution feeders

We will reduce the number of metropolitan distribution feeders that are loaded above 80%[65] by the end of AA3, thereby significantly reducing the number of customers at risk from long-duration outages. We will reduce the maximum utilisation of feeders in the Perth CBD under normal operating conditions to 50%, to provide the higher level of network security required by the Technical Rules.

This ensures that if a fault occurs on a feeder, the affected load can be supplied by other feeders without exceeding their rating. Supply is able to be maintained after a brief outage during the fault event. Customers will be able to remain connected to the network, whilst repairs are being made to rectify the fault.

For example, the failure of one feeder in a group of five inter-connectable feeders would require the remaining four feeders to support the affected load. If each of the four feeders is loaded to 80% of their rating, then following the fault, the feeders would be loaded to 100% of their rating. Similarly the failure of one feeder in a group of four inter-connectable feeders would require the remaining three feeders to support the affected load. If each of the three feeders is loaded to 66% of their rating, then following the fault, the feeders would be loaded to 100% of their rating.

The Australian benchmark for maximum individual distribution feeder utilisation is 66%. This was re-confirmed[66] following a catastrophic event in Queensland in 2004 which resulted in widespread outages and significant economic loss. A root cause identified was overly aggressive utilisation of distribution feeders (76%).

By the end of AA2, we will have 236 distribution feeders that are overloaded relative to these targeted utilisation levels, with 95 having a utilisation of 100% or more. During AA3, we will identify and address overloaded feeders as part of the annual planning process to ensure no shared distribution feeders have greater than 80% utilisation by the end of the period. Typical network solutions to address overloaded feeders consist of:

- upgrading the existing feeder to a higher capacity cable (keeping within current standards)
- installing a new feeder
- rebalancing or transferring the loads to existing interconnected feeders
- demand side management solutions

In total approximately 220 km of cable will be installed over the AA3 period to reduce the utilisation of distribution feeders. Examples of specific projects that will be undertaken during AA3 are set out in Table 47.

[65] The level of interconnection of distribution feeders in the Perth metropolitan area allows a target utilisation of 80% which is higher than the national benchmark level of 66%.
[66] Electricity Distribution and Service Delivery (Somerville report 2004), available at: http://www.deedi.qld.gov.au/documents/energy/Factsheet_-_Electricity_distribution_planning_and_service_standards.pdf

Table 47: Examples of AA3 projects to address overloaded distribution feeders

Type of project	Examples	AA3 expenditure ($ million real at 30 June 2012)
New distribution feeders	Padbury – Install new feeders to offload PBY516	1.30
Reinforce distribution feeders	Kalamunda – Feeder reinforcement	1.50
Transfer load	Clarence St. and Collier network reconfiguration for load balancing	0.88

Meeting voltage limits

Voltage limits are specified in the *Technical Rules* to ensure the safe and efficient operation of customer loads. The voltage on distribution feeders reduces as the load supplied by the feeder increases. As the load on a feeder increases, the voltage may reduce to a level that is outside the allowable range. This is predominant seen on long feeders, mostly in the rural areas. If no action is taken to increase the voltage, it may reduce to the extent that connected equipment and appliances will not function correctly or even at all.

This is analogous to pumping water through a long pipeline. As more water is pumped through, the water pressure reduces as it moves through the pipeline further away from the pump or pressure source.

We analyse the performance of the distribution network and identify where the voltage may be too low using power simulation software and network peak loading data. Once low voltage feeders are identified, we plan for remedial measures to maintain voltage support of the feeders. Such measures include the reinforcement of distribution feeders, installation of capacitor banks, voltage regulators, or the transfer of load to other parts of the network.

This is analogous to installing booster pumps at a point or points along a water pipeline to increase the water pressure.

During AA3, we will install two capacitor banks and approximately 24 voltage regulators to ensure voltage limits are met. Examples of specific projects that will be undertaken during AA3 to ensure voltage limits are set out in Table 48.

Table 48: Examples of AA3 projects to ensure voltage limits are met

Type of project	Examples	AA3 expenditure ($ million real at 30 June 2012)
Capacitor banks	Regans – installation of two capacitor banks	0.25
Voltage regulators	Northam township – installation of a voltage regulator	0.60
Reinforce distribution feeder	Pinjarra – reinforce feeder PNJ527	0.59

Maintaining balanced loads

Western Power’s distribution network is predominantly a three phase configuration (with three conductors per circuit). In certain rural areas we have established extensive single phase networks which are sufficient to support the electricity needs of the area or locality (and where a more costly higher capacity three phase network cannot be justified).

Single phase networks can lead to a load imbalance on the three phase network that supplies them. This will in turn lead to a voltage imbalance on the three phase network. This affects the quality of the supply to existing customers and can cause electrical interference with any nearby telecommunications circuits affecting their ability to function correctly. If the voltage unbalance is not corrected, it could lead to mal-operation of their equipment or prevent new customers from connecting.

Voltage unbalance is identified by power simulation software and network peak loading data or through customer complaints of poor power quality.

Two options to resolve this issue are the installation or upgrade of isolation transformers at the three phase to single phase transition on the network, or the upgrade of the single phase networks to three phase.

During AA3, we will install 100 isolation transformers and will upgrade 52 single phase distribution feeders to three phase.

7.1.2.2 Transmission driven

In AA3 we will invest $59 million, 14% of forecast distribution capacity expansion expenditure, on projects that are planned to be undertaken in conjunction with transmission capacity expansion projects. The distribution capacity expansion projects arise out of the need to:

- provide distribution capacity to accommodate new zone substation capacity and interconnection
- provide distribution feeder load transfer capability that enables utilisation of existing zone substation capacity
- maintain clearances between distribution and transmission assets as transmission lines are developed or augmented

The drivers and justification for these projects are discussed in Appendix O: Transmission Network Development Plan. Examples of specific projects that will be undertaken during AA3 are set out in Table 49.

Table 49: Examples of AA3 transmission driven projects

Transmission driven project	Examples	AA3 expenditure ($ million real at 30 June 2012)
Balcatta – new substation	Install new distribution feeders in Balcatta zone substation. Reconfigure North Beach and Arkana distribution network to accommodate Balcatta feeders.	0.82
Henley Brook – install second transformer	Transfer feeders from Henley Brook transformer 1 switchboard to new switchboard.	0.31
Joondalup – install second transformer	Installation of new feeders in Joondalup zone substation. Reconfigure Wanneroo and Mullaloo distribution network to accommodate Joondalup feeders.	1.51

7.1.2.3 Overloaded transformers and LV cables

In AA3 we will invest $58 million, 14% of forecast distribution capacity expansion expenditure, to address overloaded transformers and low voltage (LV) cables to ensure that service levels are maintained, in accordance with the Access Code.

As distribution transformers and low voltage cables become overloaded, there is an increasing likelihood of failure resulting in public safety risk and disruptions to customer supply. In 2004, we introduced the transformer overload mitigation strategy in response to a significant number of distribution transformer failures. Since inception of the program, we have reduced the number of catastrophic transformer failures from more than 50 per annum to five or less per annum.

The program targets transformers with a capacity greater than 100kVA that are predicted to be loaded above 135% of their cyclic rating during consecutive days of high temperature. Replacement of overloaded transformers addresses the need for sufficient capacity on these assets to accommodate the underlying load growth and the ability to connect customers onto the low voltage network.

In AA3 we will replace approximately 650 distribution transformers through the overloaded transformer program.

LV cable upgrades are replaced following repetitive fuse operations. LV cables account for less than 6% of total expenditure on this program, approximately $600k per annum.

7.1.2.4 Fault levels and protection

In AA3 we will invest $52 million, 13% of forecast distribution capacity expansion expenditure, to address rising fault levels on the distribution network and the need for more sensitive protection settings, as the network grows.

Addressing fault levels

When faults occur on the electricity network, a current path to earth is established. The current that flows is referred to as the fault current, and is generally much higher than the normal load current. The maximum fault current that may flow is referred to as the fault level.

The equipment in the distribution network is designed to withstand a certain fault level. If the fault current exceeds this fault level, the physical characteristics of the conductor will be adversely affected. This may lead to burning of the conductor to the ground or a permanent sagging of the conductor, leading to a breach of the safety clearances. Both of these lead to a public safety risk.

As the electricity network grows over time, the fault levels rise. If the fault levels rise to a level that exceeds the fault level rating of the equipment, action needs to be taken to reduce the fault levels, replace the equipment with equipment that has a higher fault level rating, or increase the level of protection on the relevant section of conductor to prevent damage.

There is currently 490 km of conductor in the Perth metropolitan region which is rated below the fault level and needs to be replaced in compliance with the *Technical Rules*. Our strategy is to replace or adequately protect the relevant conductors, within a 10 year period.

In AA3 we will replace 165 km of conductors.

More sensitive protection settings

To ensure that equipment is not damaged when faults occur, protection devices are set to isolate the fault. With general load growth and expansion of the distribution network, the protection devices installed may no longer be sufficiently sensitive to detect (and initiate isolation of) faults in the extremities of the distribution network to prevent damage to our distribution assets as required by the *Technical Rules*. If this occurs, faults may remain on the network until (for example) the conductor burns to break the circuit and isolate the fault. This is an undesirable outcome because it damages the assets affecting supply to customers, and presents a safety and fire risk.

This issue can be resolved by investing in additional protection devices on the network and/or adjusting the sensitivity of devices that are already in service. Detailed protection studies are undertaken periodically to confirm the extent of the issue.

In AA3 approximately 63 reclosers will be installed at various locations in the network and protection settings on protection devices (such as circuit breakers and reclosers) changed as required.

7.1.3 Gifted assets

In AA3 we will accept $321 million of gifted distribution assets ($64 million per annum). This represents 9% of forecast distribution capital expenditure.

These assets are not added to the capital base because we do not incur the capital costs for their construction. They are constructed by third parties and transferred to Western Power to own and operate. It is nonetheless important that they be forecast if likely to arise so that we can ensure adequate operating and maintenance costs for these assets once ownership has been transferred to Western Power and recovery of tax (see section 12.6 of the AAI).

Gifted assets usually comprise residential, broadacre and commercial or industrial subdivisions where the land developer has installed the electricity distribution and reticulated network infrastructure to supply the lots in the development. We also receive streetlight assets as gifted assets from local government authorities.

We make a quality assessment of the infrastructure prior to accepting the assets onto the Western Power Network to ensure they meet relevant quality standards and legislative requirements.

The AA3 forecast has been determined based on the current activity in the land development area and the corresponding of gifted assets expected to be value received and recognised by Western Power, approximately $5,700 per subdivision site.

7.2 Asset replacement and renewal

In AA3 we will invest $1.245 billion, 35% of AA3 distribution network capital expenditure, to replace and reinforce existing assets on our distribution network. Of this, $44 million will be contributed by the Government or individual customers.

Our categories of expenditure for replacing and renewing assets on the distribution network comprise:

- *asset replacement* – investment driven by the age, condition and performance of the bulk of our distribution assets
- *State Underground Power Program* – investment to retrofit older urban areas with underground power
- *metering* – investment to supply and install meters, including the replacement of 280,000 non-compliant meters, enabling Western Power and downstream electricity market participants to objectively and reliably monitor electricity consumption
- *smart grid* – investment to install a communications backbone that will enable grid-side leverage of smart grid capabilities made possible through smart meters

7.2.1 Asset replacement

In AA3 we will invest $919 million to replace distribution assets. This represents 26% of forecast distribution network capital expenditure.

Asset replacement addresses the risks associated with the condition of our existing distribution assets, to ensure that the quality, reliability and security of electricity supply and safe operation of the network are maintained. The increased level of investment in AA3 asset replacement is to address the high and increasing risk associated with the potential failure of distribution assets given the increasing age and deteriorating condition of the assets. This includes a significant increase in the volume of pole replacements and reinforcements to carry out our Wood Pole Management Plan and address the recommendations under *Energy Safety Order 01-2009*. It also includes an increased replacement of overhead lines to address public safety and bushfire risk associated with falling and breaking conductors.

Figure 48 shows our distribution asset replacement expenditure over the AA1 to AA3 period. The increase in investment late in AA2 and into AA3 will:

- set us on the path towards achievement of industry benchmark levels for unassisted distribution pole failure through increased volumes of distribution poles that are reinforced and replaced
- improve the age and condition of our overhead wire assets leading to a reduction in the number of wires down incidents and the number of fires initiated by wires down events
- move the replacement levels for other distribution assets towards long term sustainable levels

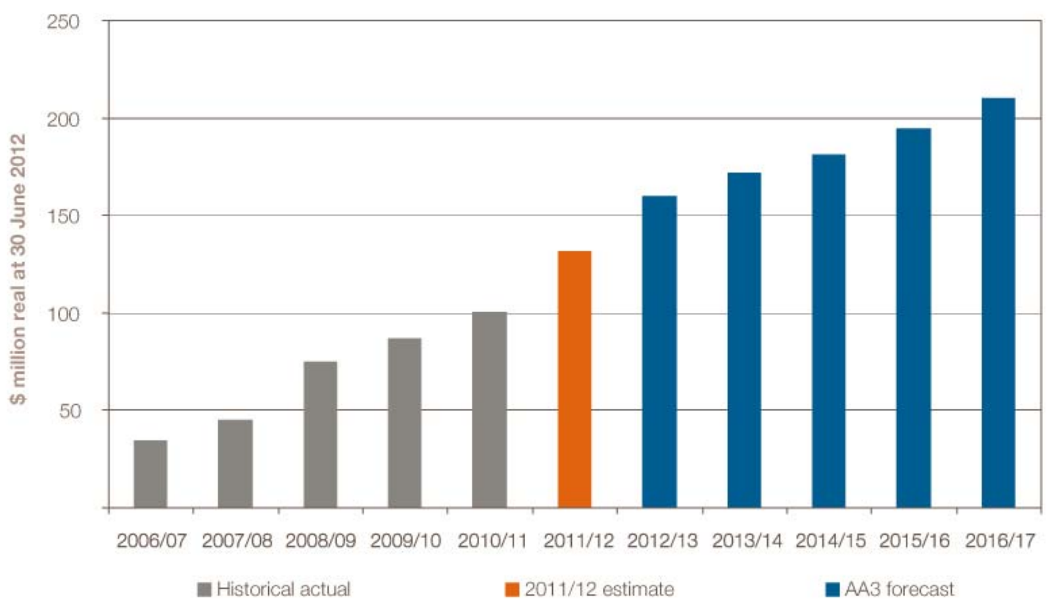

Figure 48: Distribution asset replacement historical and forecast capital expenditure

New facilities investment test

New facilities investments in distribution asset replacement are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 distribution asset replacement expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. Evidence from condition monitoring and inspections is used to demonstrate that there is a high likelihood that the safety or reliability of the covered network will not be maintained if not for the investment. This is documented in Appendix L: Network Management Plan.

AA3 distribution asset replacement expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. Using wood pole management as an example, we have efficiently minimised costs by ensuring that:

- the management plan applies to a ten year planning horizon taking into account the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period[67]
- poles are maintained or reinforced where possible and only replaced when this is no longer an option (efficiently minimising cost)
- only high risk poles are reinforced or replaced, based on serviceability defined through the inspection cycle
- work is bundled where possible so that all conditions existing on a pole are rectified at the same time, reducing the costs of crew mobilisation

REGULATORY OBLIGATIONS

The regulatory obligations that are relevant to investment in distribution asset replacement are summarised below.

Section 14 of the Electricity Industry Act 2004 requires us to have an effective asset management system:

1. It is a condition of every licence, other than a retail licence, that the licensee must -
   a) provide for an asset management system in respect of the licensee's assets;
   b) notify details of the system and any substantial changes to it to the Authority; and
   c) not less than once in every period of 24 months (or any longer period that the Authority allows) calculated from the grant of the licence, provides the Authority with a report by an independent expert acceptable to the Authority as to the effectiveness of the system.
2. *An asset management system is to set out measures that are to be taken by the licensee for the proper maintenance of assets used in the supply of electricity and in the operation of, and, where relevant, the construction of, any generating works, transmission system or distribution system*

The *Electricity (Supply Standards and System Safety) Regulations 2001* require prudent levels of asset replacement to deliver acceptable public safety outcomes. Section 10 sets out requirements for management of prescribed activities:

1. A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to -

(a) provide for the safety of persons, including employees of and contractors to the operator;

(b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and

(c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity.

We are also obliged, under sections 9 and 10 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (the Supply Code) to, as far as is reasonably practicable:

- ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum (section 9)
- reduce the effect of any interruption on a customer (section 10 (1))

It is through adequate levels of asset replacement that we are able to comply with the Supply Code and to ensure safety to people and property.

[67] Access Code, section 6.52(a) (ii)

A breakdown of AA3 forecast distribution asset replacement expenditure by activity is shown in Table 50 and Figure 49. Our investment in this category is predominantly to replace and reinforce poles (77%) and replaces conductors (13%).

Table 50: AA3 distribution asset replacement expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Pole management	117.8	127.9	139.1	150.4	165.5	700.7
Conductor management	17.2	17.2	19.1	19.8	21.4	94.8
Protective device management	6.4	7.7	8.9	10.0	8.7	41.7
Transformer management	7.0	7.1	7.3	7.5	7.8	36.7
Switchgear management	4.9	4.9	4.7	4.7	4.8	24.0
Streetlight management	2.3	2.3	2.3	2.4	2.4	11.7
Overhead line refurbishment	4.9	4.9	-	-	-	9.8
Asset replacement total	**160.4**	**172.1**	**181.4**	**194.7**	**210.7**	**919.3**

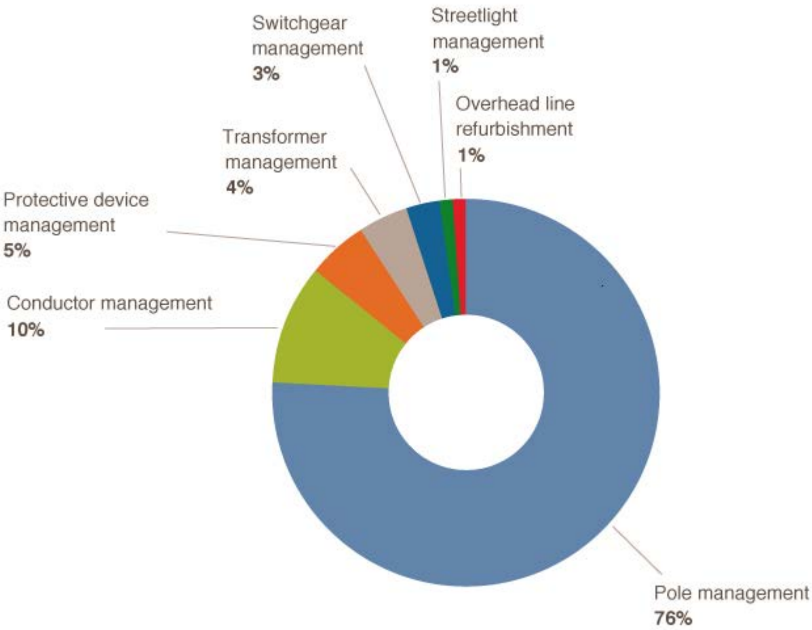

Figure 49: AA3 distribution asset replacement expenditure by activity

Each of these activities is discussed in the following sections.

7.2.1.1 Pole management

In AA3 we will invest $701 million, 76% of forecast distribution asset replacement expenditure, to replace and reinforce poles. The significant increase when compared to AA2 is required to reduce the incidence of unassisted pole failures to industry benchmark and in response to the *Energy Safety Order 01-2009*.

Poles are used to support the conductors that transport electricity around our distribution overhead network. Effective management of poles is therefore critical to the safety and reliability of our distribution network. Potential safety hazards associated with pole defects include:

- electrocution of people and livestock due to live cables being at ground level
- property damage associated with falling poles or lines
- fire due to contact of lines with ground or each other (over 25% of wood poles are located in extreme and high fire risk areas)

In addition, pole failures present business risks including:

- interruption of power to customers in the vicinity of the failure
- damage to overhead equipment
- additional operating costs for emergency repairs
- damage to or failure of adjacent poles

Around 85% of our 750,916 distribution poles are wood poles and 13% are metal with the remainder being concrete poles. A study commissioned in August 2008 recommended continued installation of local softwood poles in the short and medium term.

To manage the increasing number of wood pole defects and increasing average age of our poles, we have drawn from good electiricty industry practice to define and develop a 20-year wood pole management plan[68]. This plan aims to provide a long-term solution for pole issues through a combination of more robust inspection processes and significant capital investment programs. The long-term objective of the pole management program is to reduce the unassisted[69] pole failure rate to the national industry average of 0.435.

As shown in Figure 50 more aggressive investment profiles were considered, however, we believe the 20-year wood pole management plan (consistant with scenario 3) is the optimal approach to improving the overall condition of the wood pole population in line with our regulatory obligations.

[68] Available at: http://www.commerce.wa.gov.au/energysafety/PDF/Misc/WesternPower_order.pdf
[69] Unassisted means not attributable to an external factor such as storms, third party collisions or bushfire.

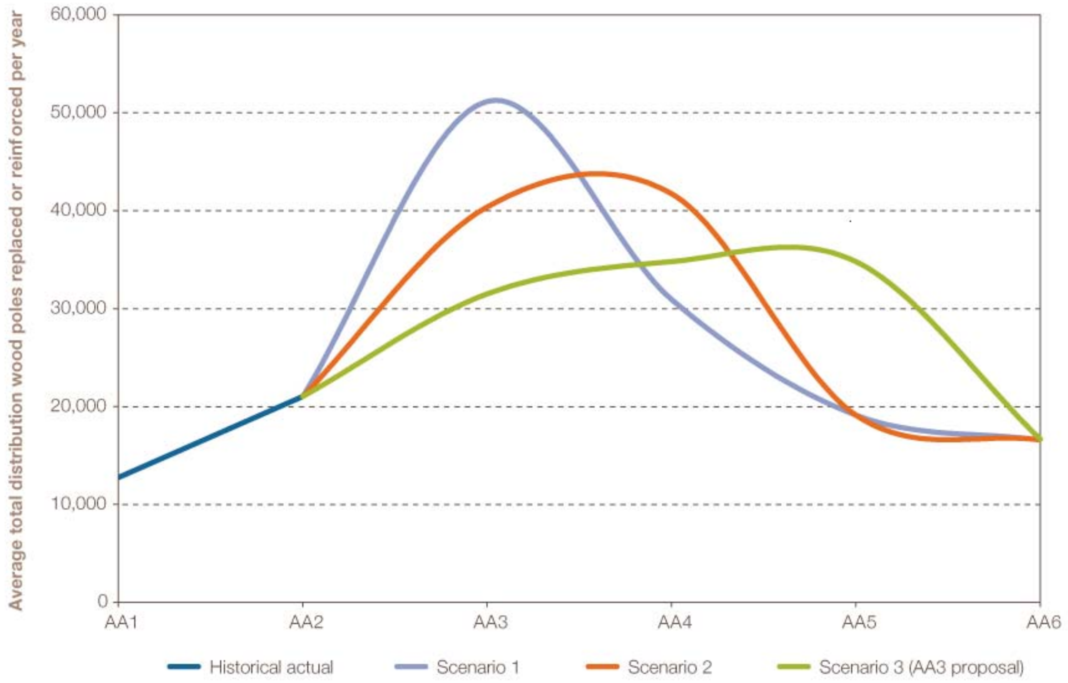

Figure 50: Comparison of options to achieve a sustainable rate of distribution wood pole replacement and reinforcement

Our wood pole management plan sets out how we are targeting good electricity industry practice including conforming to the following Energy Networks Association (ENA) Guidelines and Australian Standards[70] in relation to pole management:

- ENA document 017-2008 *Industry guideline for the inspection, assessment and maintenance of overhead power lines*[71]
- *Australian Standard AS 1720.2 – 2006 Timber structures - Timber properties*[72] which sets out the table of timber species and their general properties including natural durability and probable life expectancy for various classes of timber
- *Australian Standard AS/NZS 1170.2:2002 Structural design actions – Wind actions*[73], which sets out wind actions for use in the structures subject to wind action
- *Australian Standard AS/NZS 4676:2000 Structural design requirements for utility services poles* which sets out the requirements for the design and installation of utility services poles[74]

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[70] Available at: http://www.standards.org.au/
[71] Available at: http://infostore.saiglobal.com/store/Details.aspx?productID=1021045
[72] Available at: http://www.sdpp.standards.org.au/ActiveProjects.aspx?CommitteeNumber=TM-001&CommitteeName=Timber%20Structures
[73] Available at: http://www.saiglobal.com/online/Script/OpenDoc.asp?name=AS%2FNZS+1170%2E2%3A2002&path=http%3A%2F%2Fwww%2Esaiglobal%2Ecom%2FPDFTemp%2Fosu%2D2011%2D09%2D26%2F4727242402%2F1170%2E2%2D2002%28%2BA1%29%2Epdf&docn=AS120263382521
[74] Available at: http://www.saiglobal.com/online/Script/OpenDoc.asp?name=AS%2FNZS+4676%3A2000&path=http%3A%2F%2Fwww%2Esaiglobal%2Ecom%2FPDFTemp%2Fosu%2D2011%2D09%2D26%2F4727242402%2F4676%2Epdf&docn=AS115049875679

- *Australian Standard AS 3818.11 Timber - Heavy structural products - Visually graded - Utility poles*[75]

The plan also sets out how we are meeting the recommendations of *Energy Safety Order 01-2009* including how we:

- implemented a new pole inspection process from July 2010, including assessing pole serviceability based on pole strength and pole load
- replace or reinforce all unsupported rural poles that do not comply with nominated standards

As discussed in section 2.1.1 the serviceability index for assessing wood poles has been updated in accordance with *Energy Safety Order 01-2009*. The new methodology significantly increases the number of poles identified as being unserviceable.

A description of the serviceability index and the number of poles assessed against the new serviceability index as at June 2011 are provided in Table 51.

Table 51: Serviceability index results summary at 20 June 2011

Serviceability index	Description	Number
Greater than 1.0	Acceptable: Pole capacity greater than the design load. Pole condition adequate and suitable until next inspection cycle	93,701
Between 0.5 and 1.0	Managed: Pole capacity is less than the design load. This has a low risk of failure under everyday conditions. Managed program of replacement required.	46,216
Less than 0.5	Hazardous: Pole has no remaining life. This has a high risk of failure under everyday conditions. Pole overloaded or in poor condition and must be replaced immediately.	4,268

Error! Reference source not found.50 illustrates that 50,484 poles of the 144,185 poles[76] inspected since introduction of the new inspection method, do not meet the minimum serviceability index of 1.0, of which 4,268 require urgent attention.

Reinforcement / Replacement

Poles are reinforced and replaced on a non run-to-fail basis.

Pole condition is assessed for each pole based on the serviceability index, risk of failure (determined by a combination of condition inspections and age criteria) and the criticality of the asset to the reliability of supply. Where a pole is in poor condition and at risk of failing, we will reinforce it where possible to extend its life by up to 15 years. Where this is not possible, such as if the pole is split near the top or has already been reinforced, the pole will be replaced. We do not reinforce poles greater than 35 years old.

With the improved identification of unserviceable poles, increased pole replacement rates and better information management, our distribution pole integrity index has been

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[75] Available at: http://www.saiglobal.com/online/Script/OpenDoc.asp?name=AS+3818%2E11%2D2009&path=http%3A%2F%2Fwww%2Esaiglobal%2Ecom%2FPDFTemp%2Fosu%2D2011%2D09%2D26%2F9439179469%2F3818%2E11%2D2009%2Epdf&docn=AS073379324XAT

[76] It is estimated that 162,568 pole inspections were completed in 2010/11. Awaiting final data to finalise serviceability index split.

progressively improving over the AA2 period as discussed in section 2.1.1. However, despite the improvement, our failure rate remains the highest in Australia.

There are currently a large number of poles between 25 and 35 years old. Despite the increase in investment and volume of replacements Figure 51 shows an increase in the proportion of poles nearing the end of their useful life.

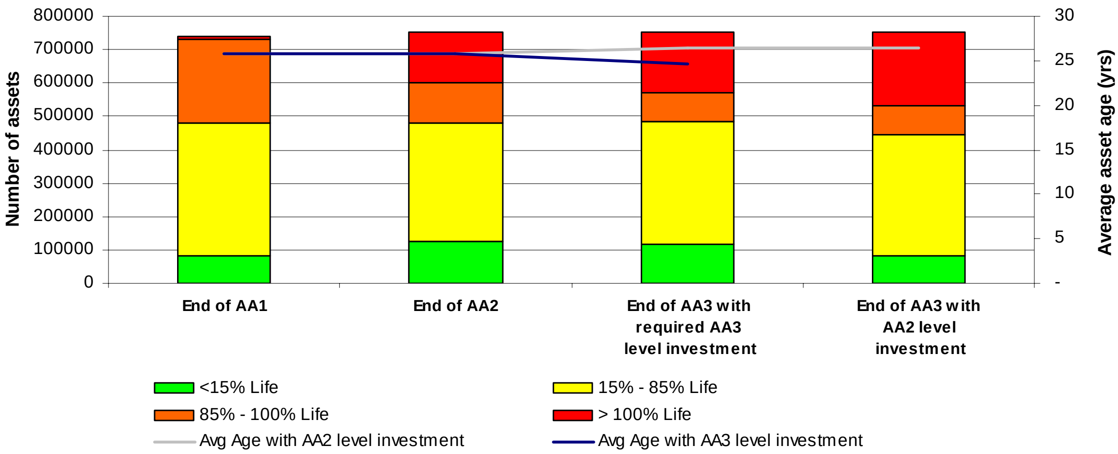

Figure 51: Pole age profile - AA3 investment vs. continuing with the AA2 investment levels

The *Energy Safety Order 01-2009* notes that *pole replacement rates in the order of 15,000 per year focussed on replacing the oldest untreated jarrah poles will not significantly reduce the risk of old jarrah pole failures. Significantly higher rates must be implemented immediately to achieve the safety outcomes required*.

In AA3 we will increase the number of poles replaced from approximately 12,400 in 2010/11 to 16,500 in 2012/13, with a further increase of 1,500 per year for the remainder of AA3. The number of poles reinforced will increase from approximately 11,400 in 2010/11 to 12,000 per year for each year of AA3.

This will achieve the sustainable level of replacement identified in our wood pole management plan by 2016/17. The increased investment in poles will deliver:

- improved condition of the pole population, moving towards an unassisted pole failure rate that is in line with our industry peers
- a reduced average age profile of the pole population in line with our wood pole management plan
- pole management practices that are in line with requirements under the *Energy Safety Order 01-2009*

7.2.1.2 Conductor management

In AA3 we will invest $95 million, 10% of forecast distribution asset replacement expenditure, to replace aged and deteriorated wires and cables.

Distribution lines transport electricity around the Western Power distribution network. These are either overhead wires or underground cables and are used at varying voltage levels (240 V to 33 kV). In line with our network management plan and as required under the *Electricity*

(Supply Standards and System Safety) Regulations 2001[77], the conductor management program undertakes the necessary maintenance, repair and replacement of aged and deteriorated overhead wires and underground cables in order to:

- reduce the incidence of bushfires initiated by 'wires-down' incidents in moderate and low fire risk areas[78]
- reduce the risk of electric shock hazard to the public and employees arising from live 'wires-down'
- reduce the risk of damage to property arising from 'wires-down' incidents
- improve the integrity of the distribution network, thereby maintaining the reliability and quality of electricity supply

We follow good electricity industry practice for conductor management including AS/NZS 7000:2010 Overhead Line Design.

Overhead wires

We have 68,561 km of overhead distribution wires. Prior to AA2, overhead wires were replaced on a run-to-fail basis. In the absence of proactive replacements, the overall average age increased and condition of the population significantly deteriorated.

The major underlying cause of conductor failures is the high rate of corrosion of steel and copper conductors in the network. Corrosion is caused principally by industrial and salt pollution in the presence of moisture and is due in part to the ageing profile of conductors. It is prominent along the coast for up to 10 km inland. Due to high corrosion, copper is no longer used in the network although currently 7% of the installed overhead distribution wires are copper. Steel, although not as corrosive as copper, also suffers corrosion issues compared to aluminium and is no longer used within the network.

Key indicators of the deteriorating condition of our overhead wires are:

- the age of the overhead wires population, as seen in Figure 52. In the absence of specific condition data, age is used as a proxy for condition. This is based on the assumption that older conductors have generally had more exposure to the elements and are subject to greater degradation
- corrosion of steel based conductors, which comprise 57% of overhead distribution wires
- the proportion of small cross sectional area copper conductors which are most susceptible to unassisted failures. Analysis of the conductor data indicates that about 28% of the copper conductor is of size 7/16 (11 mm) or smaller

[77] Available at: http://www.slp.wa.gov.au/statutes/regs.nsf/3b7e5f26432801b348256ec3002c128c/e5d3b77f97701ec3482568f000167a74/$FILE/Electricity%20Regulations%201947.PDF

[78] Investment to mitigate the likelihood of 'wires-down' incidents in extreme and high fire risk areas, see section 7.3.1.1

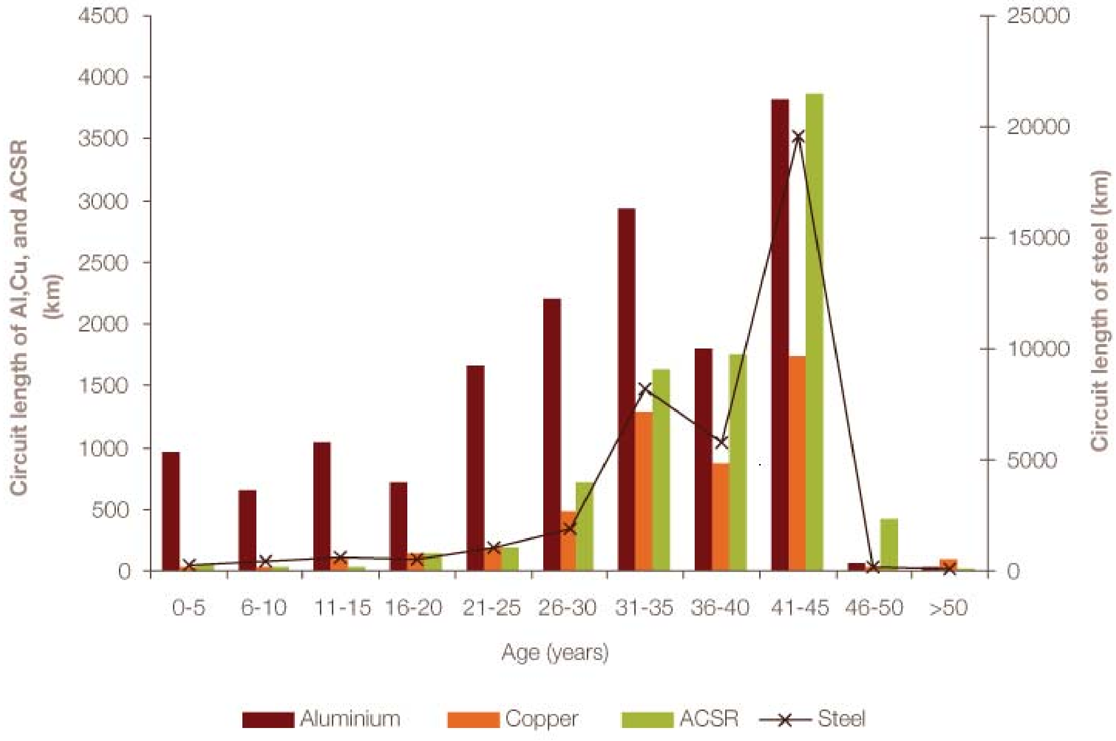

Figure 52: Distribution overhead conductor age profile

From the start of AA2, we replaced conductors based on condition, as assessed from helicopter and ground inspections and risk to system performance.

Despite the improvement in wires down incidents (see section 2.1.1) the number of bushfires caused by wires down is increasing. This is attributable to an increasing number of bushfires caused by wires falling down in medium and low fire risk areas, where past investment has been limited. In AA3 we will be targeting a reduction in the number of wires down incidents in medium to low fire risk areas where the majority of incidents occurred during AA2. Investment in this area will increase to replace 1,073 km of overhead wires during AA3.

It should be noted that an additional 1,550 km of overhead wires in high fire risk areas will be replaced during AA3 under the bushfire mitigation program, which is discussed in section 7.3.1.1.

Underground cables and cable boxes

We have 20,375 km of underground distribution cables. Failures of underground cables can cause outages for a large number of customers and can be complex and time consuming to locate and rectify. However, due to the high reliability of underground cables and the inherent difficulty in accessing them to inspect condition, these assets are only maintained (repaired) after a fault has occurred[79].

The two types of underground distribution cable used are cross linked polyethylene (XLPE) and paper insulated lead covered (PILC). XLPE cables make up about 82% of the HV underground cable network, with the remaining 18% made up of PILC cables. About 10% (100 km) of the PILC cable population has exceeded the design life of 50 years, with a

[79] Except critical circuits in the CBD area which are subject to routine condition monitoring.

further 8% (86 km) approaching this age in the next 10 years. All of the XLPE cables are under the design life of 30 years.

In AA3 we will continue routine condition monitoring of critical circuits (such as in the CBD area) and remediate prior to failures in service. We forecast that approximately 4 km of cable per year will need to be replaced under the cable fault replacement program.

Cable termination boxes are used to connect underground distribution cables to the overhead distribution network. Of the 13,163 cable termination boxes in the Western Power Network, a small proportion are of the Henley cable box type. These have a history of failing in service (nine failed in 2009/10), with failure potentially causing explosion and the projection of cast iron fragments at high velocity over a wide area around the installation. This has the potential to compromise safety of the general public as well as maintenance personnel working in the vicinity, and can cause damage or bushfires. 118 will be replaced in AA2.

In AA3 we will replace the remaining 236 Henley cable termination boxes in service.

7.2.1.3 Protective device management

In AA3 we will invest $42 million, 5% of forecast distribution asset replacement expenditure, to replace protection devices such as reclosers, sectionalisers, surge arrestors and drop-out expulsion fuses. This increase above AA2 levels largely reflects an increase in the replacement volumes of both drop-out fuses and reclosers.

The function of protection devices is to promptly remove from service any elements of a power system suffering a short circuit, or operating in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system. Replacement of defective protective devices ensures that these are in a position to provide protection to the primary assets. This means that they help to minimise damage and improve service by not introducing additional risk as a result of inadequate condition, performance or operation.

Expulsion drop-out fuses

Expulsion drop-out fuses are used to protect transformers, cables and network spurs from overload and fault conditions. Under fault conditions, when the current flow exceeds the rating of the fuse, the fuse carrier ‘drops out’ of a fuse bracket. The hanging fuse carrier facilitates identification of a blown fuse and assists repair crews to identify faults quickly.

Expulsion drop-out fuses are managed on a non run-to-fail basis. They are inspected four yearly as part of the bundled wood pole inspection program and are replaced when they are identified as being no longer operable.

There are currently 9,385 expulsion drop-out fuses that are located in medium and low fire risk areas that have a manufacturing defect affecting the fuses’ ability to operate correctly. The program to replace these commenced in AA2. We are progressively ramping up our replacement volumes as delivery capacity increases. This program is expected to continue until the end of AA3 by which time all the defective units will have been replaced.

Reclosers

Reclosers provide the functionality to interrupt permanent faults and limit interruptions due to transient faults to a very short duration, thereby preventing asset damage and reducing the impact of potential network outages. The incorrect operation, failure, or absence of reclosers will have an adverse impact on the reliability, power quality, safety and bushfire mitigation strategies.

Reclosers are managed on a non run-to-fail basis. They are inspected annually as part of the overhead switchgear bundled inspection program.

A significant proportion of reclosers are the hydraulic (non-automated) reclosers. Non-automated reclosers impede the bushfire mitigation plan in extreme and high fire risk zones because their settings cannot be remotely adjusted from the East Perth Control Centre.

In AA3 we will increase replacement rates progressively over the period to replace a total of 210 reclosers. Driving the volume increase is a dedicated program for replacement of all remaining hydraulic reclosers in extreme, high and moderate fire risk areas. Replacing hydraulic reclosers with remote controllable electronic reclosers will provide remote control and monitoring functionality to meet bushfire risk management objectives.

In addition, we will proactively replace 50% of single phase hydraulic reclosers not in these fire risk areas. The balance of the hydraulic reclosers will be targeted for replacement by June 2022.

Other types of reclosers will continue to be replaced on failure. AA3 failure rates are expected to be consistent with historical trends (approximately 13 per year).

Surge arrestors

The main function of surge arrestors is to limit surge voltages caused by lightning to prevent any serious damage to the primary plant and prevent the occurrence of explosive failures. They provide vital protection for high value distribution primary plant such as distribution transformers, reclosers, load break switches, voltage regulators, capacitor banks and underground cables. We have over 27,000 surge arrestors installed at approximately 23,700 locations on the distribution network.

There are no suitable or reliable non-destructive on-line tests to assess the condition of surge arrestors. As a result, surge arrestors have historically been replaced on failure.

However surge arresters, particularly old porcelain types, can fail explosively. Thin and sharp particles (shrapnel) are expelled when they explode, which can cause injury to the general public and our personnel in the vicinity. This also has the potential to start bushfires on extreme and high fire risk days.

We have therefore commenced a targeted program to proactively replace surge arrestors that have visible defects. Inspection classifications are:

- broken – the body of the surge arrestor has been exposed to mechanical force that has damaged it
- unserviceable – the surge arrestor has been exposed to overvoltage and/or surge current beyond that for which it was designed, and has been damaged to the extent that it cannot properly operate anymore and is thus not protecting the network
- blown – the surge arrestor has operated and has to be replaced
- missing – the surge arrestor is not where it is supposed to be

In AA3 surge arrestors will be replaced on the basis of in-service failures and those identified as unserviceable through inspection. Approximately 1,260 surge arrestors will be replaced over the period.

Sectionalisers

Sectionalisers operate as isolating devices. They count the number of operations of the recloser in the event of a fault. After a preset number of operations of the recloser, the sectionaliser will open its contacts whilst the network is in a de-energised state, so as to isolate the faulted section of the network.

Sectionalisers are managed on a non run-to-fail basis. They are inspected four yearly as part of the overhead switchgear bundled inspection program.

Most sectionalisers in the Western Power Network are single phase (99%), and about 17% of these are the older, electro-mechanical type.

The key issues that are affecting the performance of our sectionalisers are:

- in-service failures due to mechanical breakdown, rust (housing) and oil leakage. This particularly affects electro-mechanical types. There is an average of 8 in service failures per year
- performance issues with the Westec type electro-mechanical sectionaliser of which there are currently 114 units in the Western Power Network

In AA3 we will continue the program from 2011/12 to proactively replace approximately 8 Westec type electro-mechanical sectionalisers per annum. Over a 15 year period the entire population will be replaced.

Other sectionalisers that fail in service will be replaced. AA3 failure rates are expected to be consistent with historical trends (approximately eight per year).

7.2.1.4 Transformer management

In AA3 we will invest $37 million, 4% of forecast distribution asset replacement expenditure, to replace distribution transformers and voltage regulators. This is an increase above AA2 levels which reflects an increase in the replacement level of transformers as well as initiation of a replacement program for voltage regulators.

Distribution transformers

Distribution transformers are mounted on poles or on the ground and are most commonly used to transform high voltages (6.6 kV, 11 kV, 22 kV or 33 kV) down to the low voltages (240 V single phase or 415 V three phase) used by most electricity consumers[80].

Of the 67,404 distribution transformers installed in the Western Power Network there are 10,600 (16%) with a capacity of 300 kVA or greater.

<u>Distribution transformers with a capacity of 300 kVA or greater</u>

Distribution ground mounted transformers with a capacity of 300 kVA or greater are managed as N-RTF assets as failure can have an impact on either a large number of domestic customers, or a single industrial customer.

These transformers have a life expectancy of between 35 - 45 years. Currently 11% of ground mounted distribution transformers with a capacity of ≥ 300 kVA or greater are more than 40 years old and are likely to be approaching the end of their useful operational life.

Transformers are only replaced on condition. Common issues with this population of assets that would require replacement include severe corrosion or rust on the transformer tank and major oil leaks from radiator fins. These assets are also replaced as a result of lightning, and vehicles colliding with these assets.

<u>Distribution transformers with a capacity less than 300 kVA</u>

More than 56,000 of our distribution transformers 67,404 total have a capacity less than 300 kVA. Over 40,000 of these have a capacity less than 50 kVA. Because of the volume of assets it is impractical to adequately inspect all these transformers and therefore they are reactively replaced, that is they are RTF.

In AA3 we will replace 5,353 distribution transformers across all types and sizes.

[80] In rural areas we also use single phase transformers with split phase secondary windings to transform high voltages (12.7 kV and 19.1 kV) to low voltages (2 x 240 V single phase or 1 x 480 V two phase).

7.2.1.5 Switchgear management

In AA3 we will invest $24 million, 3% of forecast distribution asset replacement expenditure, to replace unserviceable switchgear. This increase above AA2 levels largely reflects an increased focus on completing the replacement program for unserviceable ring main units.

Switchgear consists of ring main units, capacitor banks and load break switches. Switchgear provides a connection point for new installations, isolation of supply during faults and for maintenance and flexibility of network operation. The switchgear operates at voltages of 6.6 kV, 11 kV, 22 kV or 33 kV.

Ring main units

Ring main units provide a connection point for new underground installations, isolation of supply for maintenance and flexibility of network operation. They are located at substations, generally with the distribution transformers. There are currently 5,098 ring main units in the Western Power Network.

Failure of ring main units can lead to flashovers. These involve explosions that are generally contained within the kiosk housing the unit however they can cause substantial damage and present significant safety risks to personnel that may be in the vicinity. Other potential impacts include:

- loss of supply for customers in the immediate area
- loss of supply for customers in a larger area if the failed ring main unit would otherwise have been used to isolate parts of the network for maintenance or augmentation work
- possible damage to the network from the fault current when a unit fails

An issue has arisen affecting Hazemeyer ring main units. These units pose a safety risk and will be replaced by the end of the AA3 period, at a rate of approximately 2 per annum.

General issues affecting ring main units include corrosion, partial discharge or low SF_6 gas pressure. Approximately 40 replacements per annum are required to address ring main units identified through substation condition assessments or inspections. Approximately 12 replacements per annum will address in-service failures.

In AA3 we will replace 54 ring main units per year. This represents 5.3 % of the population over the AA3 period.

Capacitor banks

Capacitor banks provide voltage support and power factor correction whilst improving the performance of the network and power quality. There are 341 distribution capacity banks in service in the Western Power Network.

Condition assessments identify the capacitor banks that are reaching the end of their operational life. The treatment of such units is individualised and applied on a case by case basis.

AA3 failure rates are expected to be consistent with historical trends (approximately four per year).

Load break switches

Load break switches are managed on a run-to-fail basis. AA3 failure rates are expected to be consistent with historical trends (approximately one per year).

7.2.1.6 Streetlight management

In AA3 we will invest $12 million, 1% of forecast distribution asset replacement expenditure, to replace streetlight lamps (luminaires) and dedicated metal streetlight poles. This is an increase over AA2 investment which reflects an increase in unserviceable streetlight poles as well as an increase in the expected rate of luminaire failure.

Western Power's network has 223,559 streetlights, of which approximately 101,000 are on dedicated poles and the remainder are on low voltage distribution poles. Streetlights have enclosed lamps (or luminaires) that are supplied by the distribution network.

Continual maintenance of streetlights is necessary to ensure they are operating correctly. Failure to repair streetlights affects the level of road illumination which has the potential to compromise public safety. Failure of the associated circuits can result in earthing problems, which can cause electric shocks, as well as a potential loss of lighting.

Streetlights are required to be repaired within a specific time to meet the obligations set out in clause 13.9 of the *Code of Conduct for Small Use Electricity Customers*, in the *Customer Charter* and the service standard benchmarks for street lighting reference services.

There are two programs contained within this activity:

- replacement of dedicated metal streetlight poles that have been assessed as unserviceable during routine or emergency maintenance activities
- replacement of luminaires that have been assessed as unserviceable during routine or emergency maintenance activities

Individual components of the streetlight are replaced where possible under routine maintenance programs. However where the luminaire has deteriorated to the extent that it is neither economic nor acceptable on technical and safety grounds to repair or refurbish, the complete luminaire will be replaced.

In AA3 we will replace 153 metal streetlight poles per year. This is an increase from historical replacement rates as there was an increase in the number of unserviceable poles recorded during the most recent inspection cycle. We will also replace 5,155 luminaires per year. The volume of luminaires to be replaced is based on the expected annual number of failures and takes into account annual growth levels.

7.2.1.7 Overhead line refurbishment

In AA3 we will invest $10 million, 1% of forecast distribution asset replacement expenditure, to refurbish overhead lines. This activity is initiated when significant work is required to address multiple maintenance issues that have been identified on a single line. In this case, the optimum solution is often to refurbish as a single project rather than performing individual maintenance activities. The benefits of proceeding with a refurbishment are

- better allocation of resources to improve the combined conditions on the feeder
- reduced longer term maintenance
- maintained reliability

An example is the MOR 610 Dalwallinu feeder project. Multiple sections of this line will be replaced during AA3.

7.2.2 Smart grid

In AA3 we will invest $91 million to deliver smart metering infrastructure (SMI) and smart grid functionality to sections of the Western Power Network. This represents 3% of forecast distribution network capital expenditure.

The installation of SMI is the next step in our evolution towards building an intelligent network, which aims to improve operational and capital efficiency and meet the changing needs of customers and stakeholders. We are building on the successful smart grid foundation project completed in AA2 which included piloting SMI technologies and education based customer engagement programs. This information was used to develop a comprehensive cost benefit analysis, which conservatively shows a net benefit to the market of $149 million over 20 years based on the proposed deployment scenario. For further information, see Appendix R: Smart grid proposal

The phased deployment of smart meters in AA3 leverages the unique opportunity presented by the mandatory requirement to replace 280,000 non-compliant three phase meters by December 2015 (see section 7.2.4). In total this will result in approximately a third of our meter population being smart meters by the end of AA3. In addition, we have proposed a phased SMI deployment program targeting high energy consumers for new or scheduled three phase meter replacement in urban and regional areas.

In AA3 we will:

- implement secure two way communications infrastructure, leveraging existing fibre backbone where possible, as well as a smart grid Network Management System (NMS) and service order interfaces
- implement network management capabilities for SMI and enabling customer, network and market products and services, e.g. Home Area Network, in-home displays, customer and installer portals, demand management programs, data and network security, software licensing and support
- incur operating expenditure (discussed in section 4.2.5) for:
    - managing smart meters
    - smart grid communications systems
    - smart grid Network Management and IT Systems
    - smart grid customer programs for peak demand and energy efficiency management
    - community engagement, education and demand management programs

Our historical investment is shown in Figure 53. In the AA2 period, smart grid costs were reported in the regulatory compliance category of expenditure. We are now reporting historical and forecast smart grid activities in a new ‘smart grid’ category of expenditure. This reflects the significant increase in forecast expenditure and ensures comparisons with historical expenditure are not distorted.

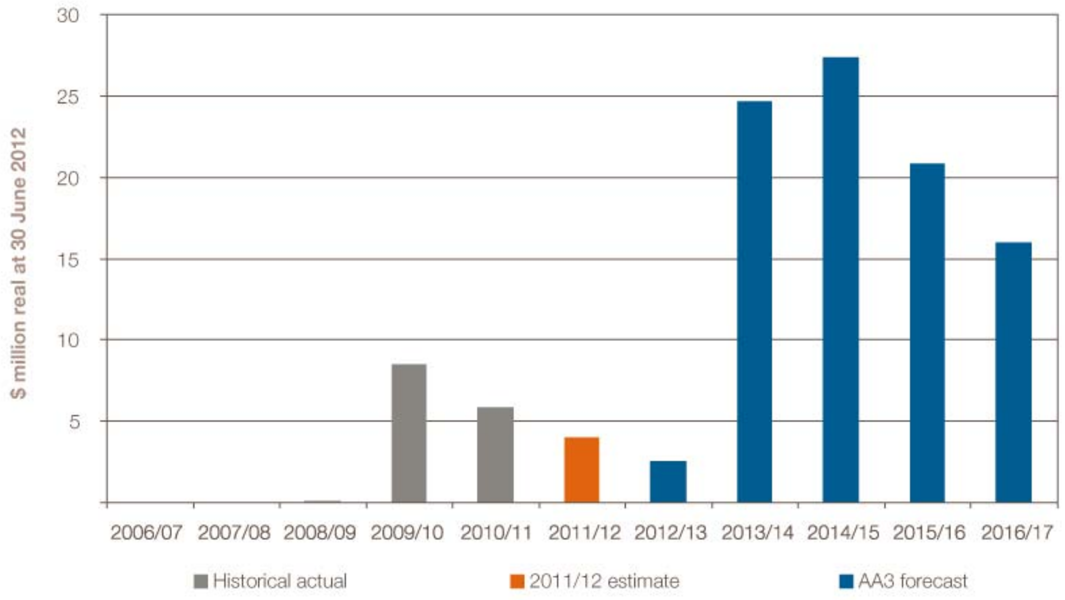

Figure 53: Distribution Smart grid historical and forecast capital expenditure

Further smart grid related expenditure is captured in other regulatory categories:

- deploying smart meters as business as usual for three phase new connections and meter exchanges – metering expenditure (see section 7.2.4)
- employing staff in the network operations control centre to manage network data obtained through the smart grid and meters – network operations operating expenditure (see section 4.2.1)

New facilities investment test

New facilities investments in smart grid are only undertaken where section 6.52(b) (ii) of the Access Code is met. Section 6.52(b) (ii) of the Access Code requires that the *new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariff.*

AA3 smart grid investment has been assessed as meeting section 6.52(b) (ii) under the Access Code. During AA2, we completed a smart grid foundation program which deployed a pilot of 11,000 smart meters and the associated communications backbone on a localised basis. This sought to inform WA policy development regarding smart meters in light of the Ministerial Council on Energy (MCE) findings that smart meter deployment in WA would provide a positive net benefit. From this pilot, we have gained insights into the costs and benefits available through smart meters.

Information from the smart grid foundation program has verified that a positive net benefit from smart meter deployment is achievable in WA. This conclusion has been reached by undertaking a detailed cost benefit analysis, assessing a range of deployment options including the proposed option. The net benefits will be delivered to Western Power and consumers of electricity over a 20 year period.

Having regard to the WA government's stated smart meter policy, but in the absence of a government mandated rollout, we have reviewed business as usual meter installation and replacement programs to ensure these provide a prudent asset platform if and when smart grid is mandated in WA. Paired with an obligation to replace a large proportion of three phase meters and to continue business as usual meter installation and exchanges, we determined that costs would be efficiently minimised over the total meter life by installing smart meters on a new and replacement basis. Even without such a mandate, a gradual deployment for business as usual activities provides sufficient net benefits to satisfy the NFIT.

If such a deployment is mandated within WA, we would make use of the unforeseen event or trigger event provisions within the access arrangement, or seek contributions from Government to recover additional costs as required.

We have revised our standard metering procurement practices on the basis of the cost benefit analysis to now include smart meters for business as usual three phase meter exchanges and new connections, effective from 1 July 2012.

A breakdown of AA3 forecast distribution smart grid expenditure by activity is shown in Table 52 and Figure 54.

Table 52: AA3 distribution smart grid expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Smart metering infrastructure	1.8	23.4	23.9	14.4	6.9	70.6
Smart grid pilot program	-	-	2.2	5.2	8.0	15.4
Grid side and demand management trials	0.7	1.2	1.2	1.2	1.1	5.5
Smart grid total	**2.6**	**24.6**	**27.4**	**20.9**	**16.0**	**91.4**

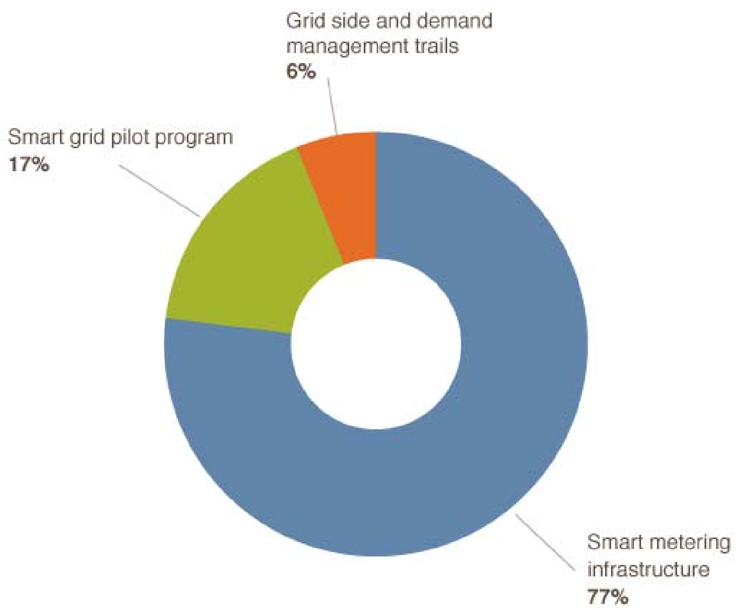

Figure 54: Distribution smart grid expenditure by activity

Each of these activities is discussed in the following sections.

7.2.2.1 Smart metering infrastructure

In AA3 we will invest an incremental $71 million, 77% of forecast smart grid capital expenditure, to replace 280,000 non-compliant meters and install 53,000 new and replacement three phase meters with MCE compliant three phase smart meters. This program will commence from 2013 onwards in urban areas and result in approximately a third of our meter population being smart meters by the end of AA3.

Growth in peak demand is a challenge for our network, requiring significant investment to maintain covered services for a summer peak that spans only two days per year. Smart grid and SMI technologies have been demonstrated to assist customers to reduce their overall energy consumption and reduce peak demand.

We have a unique opportunity to leverage the mandatory replacement of 280,000 non-compliant three phase meters. Customers with three phase meters have on average 63% higher electricity consumption than single phase customers. In our AA2 trials, we have recorded a reduction in energy usage of 10% per household on average. If this reduction in energy usage were applied to the current A1 residential retail tariff (see section 5.2.1 of the AAI for description of tariff), three phase meter customers would save approximately $170 per annum.

The smart metering technology to be deployed and associated functionality is discussed in Appendix R: Smart grid proposal.

Communication infrastructure

We will establish and maintain secure two way communications infrastructure comprising meter communications cards ($30 million), access points and relays, a smart grid-AMI Network Management System and SMI service order interfaces and demand management operational interfaces. See Figure 55 for the proposed architecture of the smart grid communications backbone.

To achieve early benefits to customers, particularly a reduction in meter reading costs, deployment of the two way communications, SMI systems and processes will be undertaken in parallel to the smart meter deployment. This is one of the key learnings from Victoria's smart meter rollout and our own smart grid foundation program trials.

The infrastructure will cover urban areas including Geraldton, Kalgoorlie, Bunbury and Albany. It will ensure communications coverage to approximately 85% of the three smart meters installed during AA3.

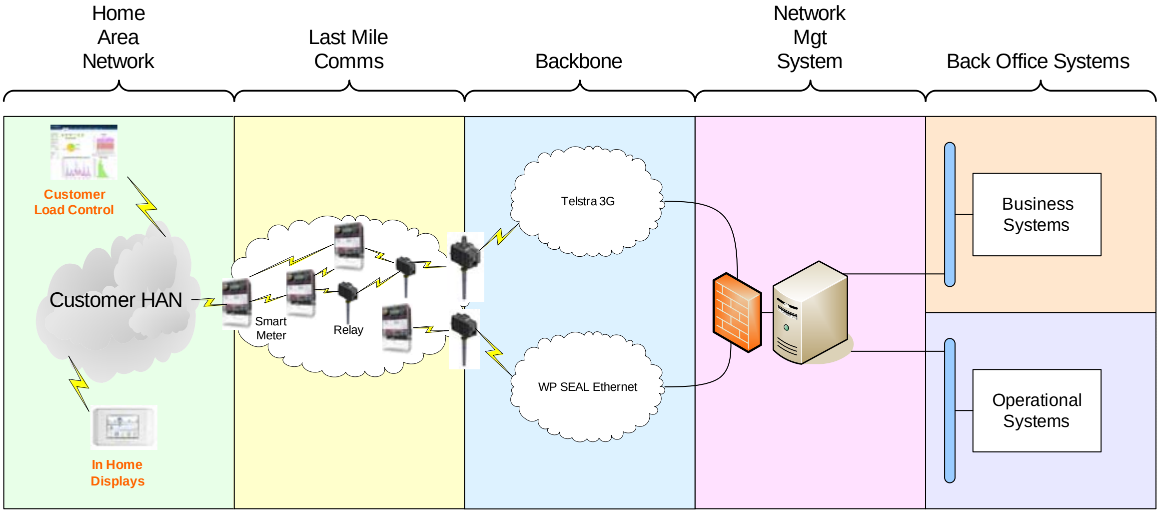

Figure 55: Architecture of Western Power's proposed communications backbone for smart grid

The customer engagement and energy management education to support the deployment of in home displays and an energy portal is discussed in section 4.2.4.4.

7.2.2.2 Smart grid pilot program

In AA3 we will invest $15 million, 17% of forecast smart grid capital expenditure on pilot programs to build demand-side management capability.

The pilot programs include costs for establishment of:

- network peak demand reduction incentive schemes
- direct load control devices for priority and smart appliances and demand management systems including integration with system management control systems
- targeted installation of power factor correction equipment in network areas identified as having bad power factor by the smart meter data

7.2.2.3 Grid side and demand management trials

In AA3 we will invest $5.5 million, 3% of forecast smart grid capital expenditure on grid-side trials to build demand-side management capability.

We will conduct a series of trials that leverage the network benefits of a smart grid to enable the network to run harder and achieve higher efficiencies without system failure. These trials will involve:

- low voltage (LV) network monitoring – real time monitoring of transformer-to-meter connectivity, which will provide transparency of data regarding which meters are connected to transformers. This information can be used to identify customers experiencing outages and inform plans for managing load on transformers. This will allow optimisation of transformers to accommodate electric vehicles, photovoltaic (PV) cells and other forms of distributed generation
- dynamic line ratings – these ratings, obtained using the smart grid sensors and communication network, will enable us to capture data regarding line conditions
- integrated LV network management – this trial will involve developing and testing smart grid capabilities to control and monitor the LV network. It will include simulating the use of electric vehicles to understand their impact on the LV network and develop optimal charging regimes, as well as understand how at an aggregated level, the demand from electric vehicles can be balanced with local wind generation
- power system network management – by integrating sensors into the smart grid communications network this trial will better inform smart grid functionality for arc detection, fire monitoring and fault monitoring
- integrating photovoltaic inverters – this trial of integrating PV inverters into home area networks will allow customers to see their PV power generation on their in home displays. System management will also have visibility and access to this data, enabling it to better manage generation and loads
- edge of grid trials – edge of grid locations generally require costly network augmentations to provide supply side solutions for reliability improvement or to address capacity constraints, and are therefore good candidates for distributed energy solutions. We will trial non-network solutions to poor reliability or capacity constraints which may consist of connecting customers to battery storage (including uninterruptible power supply systems (UPS)), smart grid connected inverters, inverter-connected diesel generators, smart load control systems or introducing more efficient appliances at a customers residence.

We will research, develop and implement distributed energy solutions to deliver reliability improvements, enable demand management and provide non-networked energy efficiency solutions for edge of grid customers experiencing capacity and reliability problems.

We have scoped these trials collaboratively across the business. This joint approach has ensured no duplication of investment and that maximum benefit can be derived from the data that we will obtain from the trials.

7.2.3 State Underground Power Program

In AA3 we will invest $58 million to meet our obligations for round 5 of the State Underground Power Program (SUPP). This represents 2% of forecast distribution network capital expenditure. Of this, the State and Local Government will contribute $44 million or 75% (see Table 53).

Following the severe storms in 1994 that left many thousands of customers in the metropolitan area and the southwest region without power for several days, the State

Government embarked on a program to retrofit older urban areas with underground power. The program aimed to provide underground power services to 50% of residential properties in Perth by 2010, with corresponding improvements in regional towns. This target has been reached and the program has been extended into the AA3 period with arrangements for SUPP round 5 (commencing in 2011/12 and due to finish by 2013/14) already formalised.

SUPP is a partnership between Western Power, the State Government and Local Government Authorities. For rounds 1 to 4 completed to date, the costs have been shared in the ratio of 28.6%, 25.8% and 45.6%, respectively.

Benefits realised from SUPP include improved reliability of supply and visual amenity.

Table 53: AA3 distribution SUPP expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
SUPP total (gross)	39.2	18.9	-	-	-	58.1
less capital contributions	29.4	14.2	-	-	-	43.6
SUPP total (net)	**9.8**	**4.7**	**-**	**-**	**-**	**14.5**

With significant increases in material and labour costs of up to 130% between 2003 and 2006, a long term fixed priced contracting strategy was entered into for round 4 of SUPP. In exchange for offering continuity of work to contractors, we ensured a fixed price contract framework based on an agreed schedule of rates. These contracting arrangements have been extended for round 5.

The investment forecasts are derived from applying current project costs and our long term fixed priced contracting strategy against the proposed projects for round 5. Round 5 projects have been agreed with the SUPP Steering Committee and Government and include:

- northern metropolitan locations including – Coolbinia, Ashfield
- southern metropolitan locations including – Salter Point, Wilson East, Ardross West, Hamilton Hill, Lathlain north and south, Coolbellup East, Shoalwater

Our forecast SUPP expenditure is compared to the historical SUPP expenditure in Figure 56.

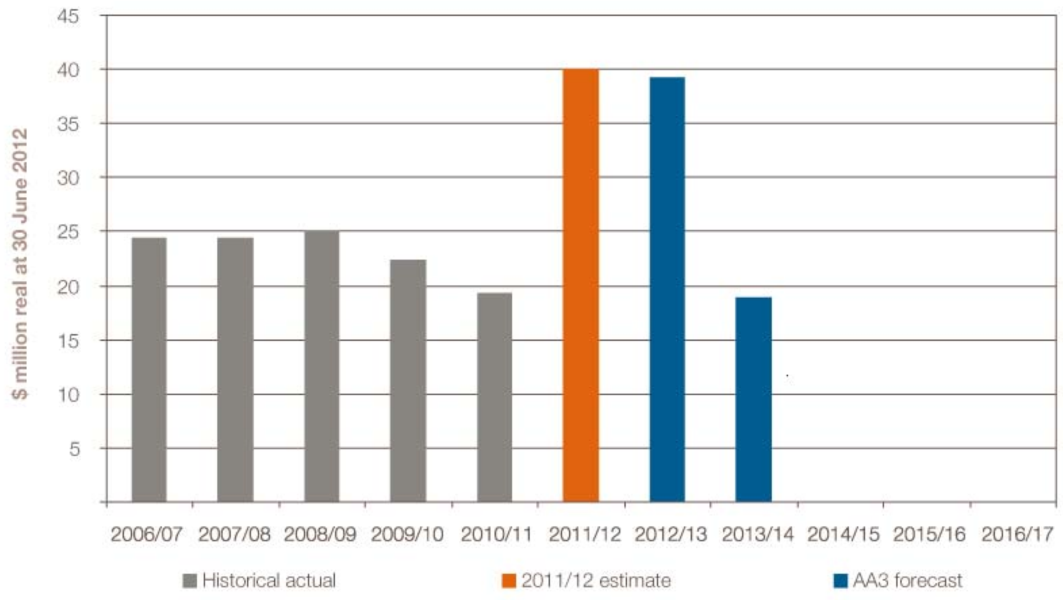

Figure 56: Distribution SUPP historical and forecast capital expenditure

There are currently no committed projects beyond round 5. If additional obligations arise for future rounds of SUPP, additional expenditure works will be sought separately to the AA3 process.

New facilities investment test

New facilities investment in SUPP is expected to only partially satisfy section 6.52(b) (iii) of the Access Code, where *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*. As a result, we only partially contribute to the cost of the program, reflecting the expected benefits in reliability and avoided maintenance costs.

AA3 SUPP expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code. In addition, we are able to leverage our existing contracting arrangements, which offer continuity of work to our contractors in exchange for a competitive fixed price contract, to ensure we are efficiently minimising costs.

REGULATORY OBLIGATIONS

SUPP works are carried out to meet our obligations under the State Government program, as outlined in the *State Underground Power Programme Terms of Reference* and the resulting Partner Agreements established for each SUPP project.

7.2.4 Metering

In AA3 we will invest $176 million, 5% of forecast distribution network capital expenditure, to install and replace meters.

This investment relates to the supply and installation of meters, enabling us and downstream electricity market participants to objectively and reliably monitor electricity consumption.

We will install and commission approximately 56,000[81] meter installations per year, of which approximately 26,000 relate to new connections and 30,000 are replacements of existing meters. The timing of this expenditure is driven by:

- customer requests for connection – see chapter 6 of the AAI for how forecasts of new customers were derived
- meter age and condition – replacement of 150,000 faulty three phase meters is driven by section 3.5(2) of the *Metering Code*[82] requiring every distribution-connected meter on the Western Power Network to be operating within prescribed measurement accuracy tolerances

In addition, we are required to replace a further 280,000 three phase meters which are non-compliant with section 6.8(d) of the *Metering Code*. We have previously sought and received exemptions for replacing this metering population. However, we are mandated to complete the replacement by December 2015. As discussed in section 7.2.2, we are leveraging this opportunity to replace these meters with MCE compliant smart meters. Only the cost of a standard interval meter is included in metering expenditure. Any incremental costs associated with installing smart meters are included in our smart grid capital expenditure.

Our AA3 metering expenditure is shown in Table 54. Figure 57 shows our distribution metering expenditure over the AA1 to AA3 period. The increase in AA3 expenditure is driven by the replacement of the 280,000 non-compliant meters.

Table 54: AA3 distribution metering expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Metering total	15.4	48.6	48.5	45.0	18.3	175.8

[81] Of the 56,000 annual meter installations, approximately 65% are single phase meters, 34% three phase meters and 1% current transformer (CT) meters.
[82] Except customers with type 7 meters commonly referred to as 'unmetered supplies'.

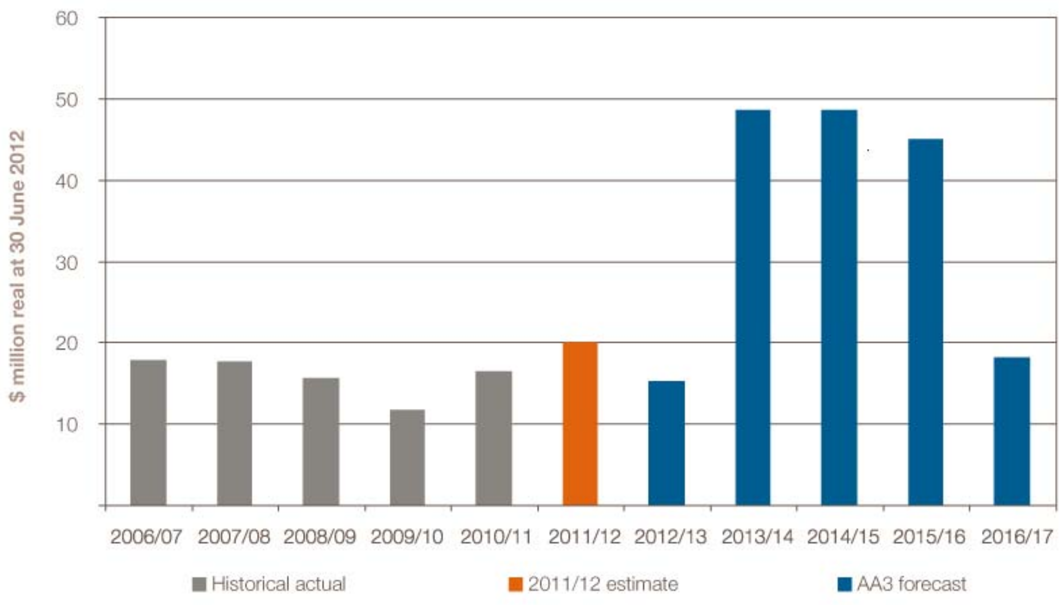

Figure 57: Distribution metering historical and forecast capital expenditure

The unit rates for installation of meters have been based on current meter prices from our preferred vendor chosen through a competitive tender process.

New facilities investment test

New facilities investments in distribution metering are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services*.

AA3 distribution metering expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. Recording and measuring energy consumption in accordance with the Metering Code and legislation listed above is a necessary component of providing contracted services.

We efficiently minimise meter costs under section 6.52(a) of the Access Code by conducting open tenders to procure meters at market tested prices.

REGULATORY OBLIGATIONS

Our AA3 investment in metering ensures compliance with our obligations under:

- the *Electricity Industry Metering Code 2005* (the Metering Code) - establishes rules for the provision of metering services
- the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008* - regulates and controls the conduct of retailers, distributors and electricity marketing agents who supply electricity to residential and small business customers, including requirements about how we must provide energy and standing data (meter data) to market participants
- the *Electricity Industry Customer Transfer Code 2004** establishes rules for the provision of meter data by us to retailers, to enable customers on the Western Power Network to transfer between retailers, and includes service levels for disconnections and reconnections of distribution-connected customers by us
- Service Level Agreements - contain the contractual obligates us as the network operator providing metering services to users
- our Customer Charter

The Metering Code contains a number of specific obligations requiring us to provide services within defined timeframes and to agreed service levels and prescribed metering accuracy tolerances.

Part 3, section 3.5 of the Metering Code requires provision and maintenance of a metering asset for each customer in the Western Power Network:

1. *a network operator must ensure that there is a metering installation at every connection point on its network which is not a Type 7 connection point*
2. *unless it is a Type 7 metering installation, a metering installation must:*
   a) *contain a device which has a visible or otherwise accessible display as detailed in clause 3.2(1); and*
   b) *have a measurement element for active energy; and*
   c) *if required by Table 3 in Appendix 1, have a measurement element for reactive energy; and*
   d) *permit collection of data at the level of accuracy required by clause 3.9.*
3. *A network operator must, for each metering installation on its network, on and from the time of its connection to the network:*
   a) *unless otherwise agreed between the network operator and a user, provide, install, operate and, subject to clause 3.5(7), maintain the metering installation in accordance with:*
      (i) *this Code; and*
      (ii) *good electricity industry practice; and*
      (iii) *the metrology procedure for the network; and*
      (iv) *the service level agreement between the network operator and the user in respect of the metering installation; and*
   b) *ensure that the metering installation complies with clause 3.9; and*
   c) *without limiting clause 3.5(3)(a) ensure that the metering equipment in the metering installation:*
      (i) *is suitable for the range of operating conditions to which it will be exposed (e.g. temperature, impulse levels); and*
      (ii) *operates within the defined limits for that metering equipment as specified in the approved metrology procedure.*

This establishes the obligation for Western Power to provide a meter and ensure its metering equipment complies with:

- the Metrology Procedure and the Metering Management Plan approved by the Authority
- the *National Measurement Act* (where no exemption applies)

* Available at http://www.erawa.com.au/2/149/48/electricity_access__customer_transfer_code.pm

7.3 Compliance

We deliver all of our distribution compliance capital expenditure through the discrete category of regulatory compliance, to meet external regulatory and legislative obligations, including technical and safety requirements.

7.3.1 Regulatory compliance

In AA3 we will invest $485 million, 14% of forecast distribution network capital expenditure, to improve compliance with our regulatory and legislative obligations for the distribution network.

Distribution regulatory compliance expenditure is one component of the total investment required to ensure compliance to all our obligations regarding performance and management of distribution network assets. Investment in this category specifically targets step changes, new obligations or identified issues with current compliance levels ensuring there is no overlap with investment in other categories. Consequently, historical trends are not indicative of future levels of investment.

Figure 58 shows our distribution compliance expenditure over the AA1 to AA3 period. The increased investment late in AA2 and into AA3 will:

- reduce the likelihood of asset initiated fires through our bushfire mitigation program, specifically targeting replacement or refurbishment of *at risk* assets including pole tops and conductors. This will reduce the likelihood of non-compliance with the *Electricity (Supply Standards and System Safety) Regulations 2001*
- reduce the risk of electrocution and improve public safety by replacing the population of ‘at risk’ overhead service connections
- reduce the likelihood of non-compliance with the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* for small use customers who must not experience more than one twelve hour duration every ten years
- reduce the likelihood of non-compliance with the *Electricity Act 1945* for LV connected customers whose supply voltage is outside the mandated system pressure of 240 V ±6%, as a result of subdivision of land in inner metropolitan and semi-rural areas

The step down in investment in 2015/16 reflects the completion of the program to replace *at risk* overhead service connections in 2014/15.

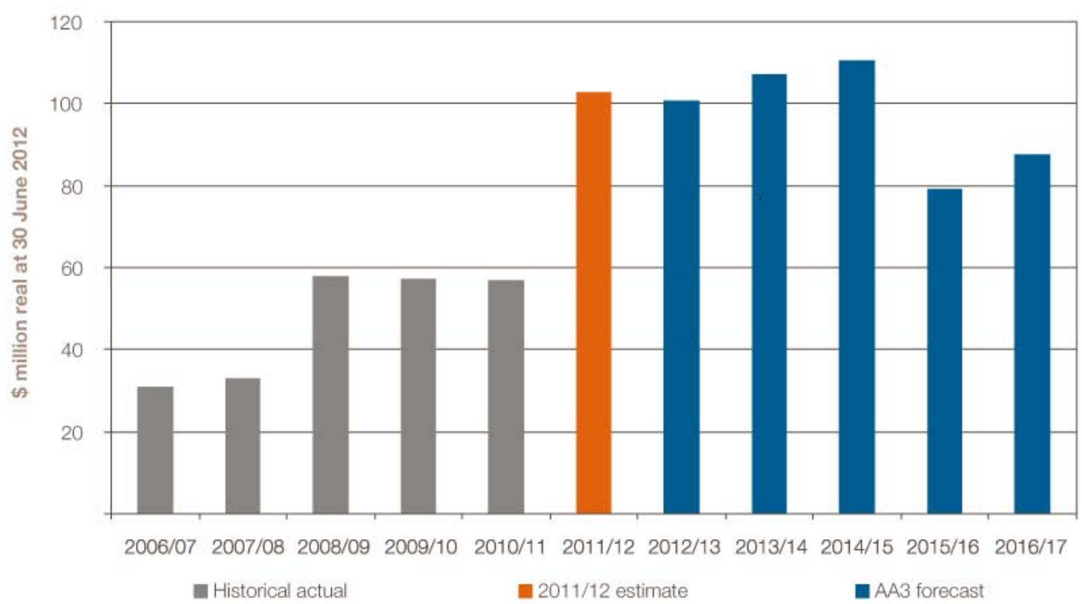

Figure 58: Distribution regulatory compliance historical and forecast capital expenditure

We have not included investment to fully comply with Regulation 17(7) of the *Environmental Protection (Noise) Regulations 1997* (Noise Regulations). In 2009 we estimated the cost to achieve full compliance with the Noise Regulations for padmount distribution transformers to be $270 million. Negotiations with the Department of Environment and Conservation and EPA have failed to achieve an acceptable or workable outcome to address this non compliance in what we consider to be a cost effective or practical manner.

We will continue our transmission noise mitigation works as outlined in section 6.4.1.5. We will continue negotiating an amendment to the Noise Regulations to exempt distribution transformers. We will define criteria for rectifying the noisiest distribution transformers based on complaints and noise exceedance in a distribution noise management plan to demonstrate responsible management of noise.

New facilities investment test

New facilities investments in distribution regulatory compliance are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services.*

AA3 distribution regulatory compliance expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. Non-compliance with relevant codes and standards is evidence that there is a high likelihood that the safety or reliability of the covered network will not be maintained if not for the investment.

AA3 distribution regulatory compliance expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code. We undertake our own cost benefit analysis when new legislation or industry standards are introduced only changing practice where we are legally obliged or it is efficient to do so. We are able to leverage our delivery partner arrangements in place for our asset replacement programs and bundle work to achieve economics of scale where appropriate.

REGULATORY OBLIGATIONS

The *Electricity (Supply Standards and System Safety) Regulations 2001* require that we must ensure that, so far as is reasonable and practicable, we carry out our activities in such a way as to provide for the safety of persons, including employees of and contractors to us. Evidence of compliance with this regulation is defined in section 11(1):

Compliance by a network operator to whom Division 2 applies with a relevant provision of —

- *a) a standard or code published under a law any jurisdiction in Australia*
- *b) a standard or code published by Standards Australia, the Electricity Supply Association of Australia, or any other body approved by the Director*
- *c) a standard or code published by any other body and approved by the Director*
- *d) a standard or code published specified in Schedule 2*

Our regulatory compliance works program has been developed to facilitate us meeting these regulations.

The specific codes and standards which Western Power is currently increasing its level of compliance or preventing a breach of compliance are identified by activity in sections 7.3.1.1 to 7.3.1.9

A breakdown of AA3 forecast distribution regulatory compliance expenditure by activity is shown in Table 55 and Figure 59.

Table 55: AA3 distribution regulatory compliance expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Bushfire mitigation	39.8	41.5	42.7	48.1	54.2	226.2
Overhead customer service connections	28.7	28.7	29.2	-	-	86.6
Reliability compliance	10.2	8.2	8.3	8.5	8.8	44.0
Substandard conductor clearance	3.5	4.6	5.9	7.1	8.5	29.5
Power quality compliance	5.9	5.5	5.2	5.2	5.4	27.2
Conductive poles	1.7	7.9	8.0	-	-	17.6
LV network upgrades	2.4	2.4	3.0	3.0	3.1	14.0
URD pillars	2.0	2.0	2.0	2.0	2.1	10.1
Other	6.5	6.5	6.2	5.4	5.6	30.2
Regulatory compliance total	**100.7**	**107.3**	**110.4**	**79.3**	**87.6**	**485.3**

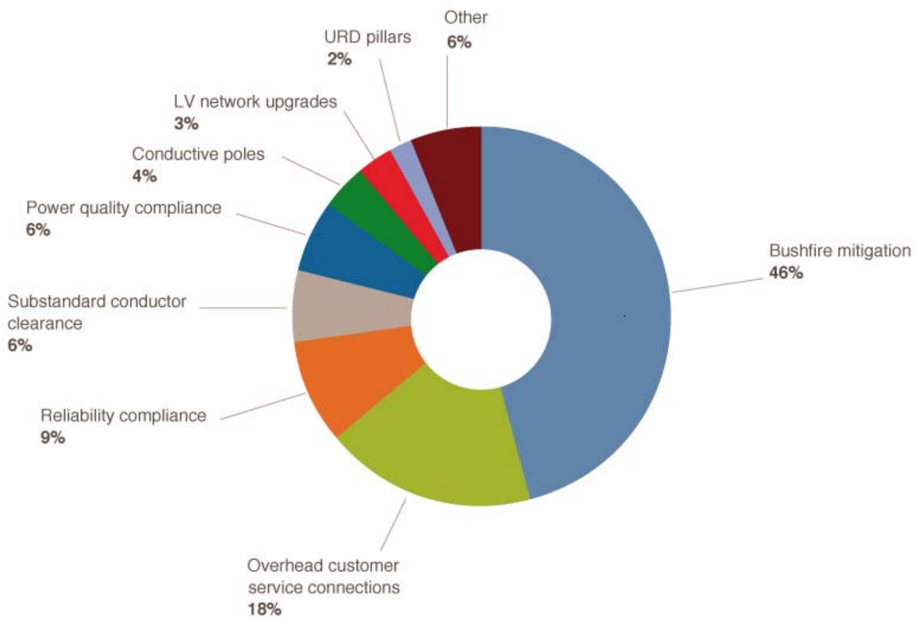

Figure 59: AA3 distribution regulatory compliance expenditure by activity

This category of investment contains mostly volumetric activities with some discrete projects.

The volume of compliance work has been determined with regard to the specific population of *at risk* assets associated with each area of non-compliance and applying any delivery constraints. We prioritise investment towards those assets that pose the highest safety risks.

Each of these activities is discussed in the following sections.

7.3.1.1 Bushfire mitigation

In AA3 we will invest $226 million, 47% of forecast distribution regulatory compliance expenditure, to reduce the likelihood of bushfires being started by assets on the Western Power Network.

Our network assets ignite a small number of bushfires each year, which may lead to public safety risks and damage to property. Bushfires also cause damage to network infrastructure, which in turn can impact critical local community services such as water pumping and communications facilities, which are essential in fighting fires and protecting communities generally.

The key metric for bushfire mitigation is the number of asset initiated fires, as discussed in section 2.1.1 and shown in Figure 60. The figure shows an increasing trend for asset initiated fires over the AA2 period. In assessing this data it is important to note we improved our processes of reporting asset initiated fires at the commencement of the AA2 period which is contributing to this increase.

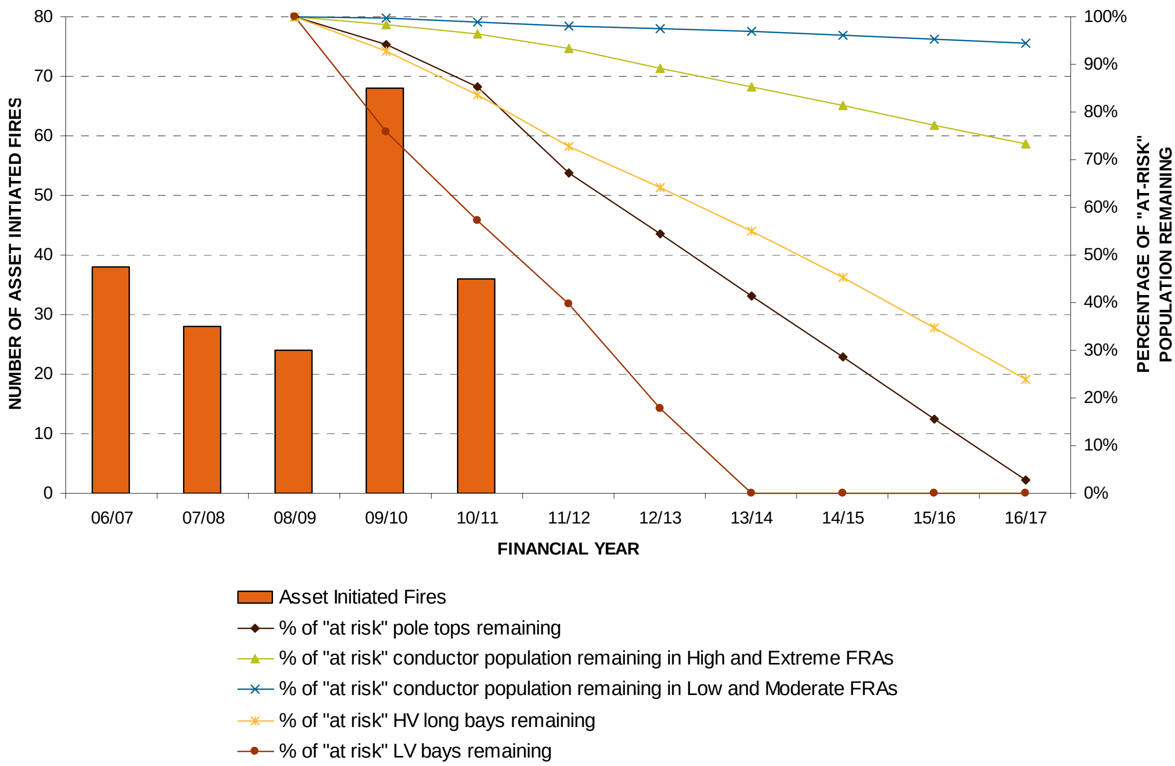

Figure 60: Asset initiated fires

The top four causes of all fires by volume are: pole top fires, equipment failure, bird / animal and wires down.

Our Bushfire Mitigation Strategy[83] informs the long term plan to reduce ignition sources arising from network assets by virtue of their condition or operation. The strategy is informed by good electricity industry practice including the Energy Networks Association's *Land management guidelines ENA DOC 019-2008*[84] and the findings of the Victorian Bushfires Royal Commission.

[83] DM8176425: *Bushfire Mitigation Strategy*
[84] Available at: http://www.ena.asn.au/?p=1239

The catastrophic bushfires in Victoria on 7 February 2009 reinforced the need to reduce the risk that power lines start bushfires. The Royal Commission concluded that five of the major fires were started by power lines. These five fires resulted in 121 deaths. We have closely followed the Royal Commission's hearings and the work of the *Powerline Bushfire Safety Taskforce*, which were established to further consider the electricity related recommendations of the Royal Commission, and concluded that we can and should do more to reduce the likelihood that our power lines start catastrophic bushfires.

In AA3 our Bushfire Management Plan[85] includes the following ongoing bushfire mitigation strategies:

- *wires down* – when wires break and fall down, dry undergrowth may ignite and start bushfires. This may occur because the potential difference between an energised wire and the ground might enable sparking as current flows from the wire to ground. In some circumstances, a fire may result. The *wires down* strategy is to accelerate the replacement of rusted or corroded conductors in areas of extreme and high fire risk
- *conductor clashing* – conductor clashing causes sparks which have been known to cause bushfires. The strategies are to install spreaders to separate low voltage (LV) conductors and to rectify parts of the high voltage (HV) network where conductors clash, for example, by adding wider cross-arms or adding an additional pole between the existing length ('bay') of conductor
- *pole top fire* – pole top fires result in system faults and can cause bushfires by pole top equipment or sparks falling to the ground and igniting vegetation. The strategies are to apply silicone coatings on pole top insulators and to use steel cross-arms and polymer insulators when poles and/or cross arms are replaced

Reduce wires down

In AA3 we will invest $118 million, 24% of forecast distribution regulatory compliance expenditure, to reduce the likelihood of wires breaking and falling down. This increase above AA2 level of investment largely reflects the necessary increase in work needed to reduce the likelihood of bushfires linked to conductor failure (wires down).

The general condition of our conductor population and discussion on the replacement of conductors in low and medium fire risk areas is discussed in section 7.2.1.2. The major underlying cause of conductor failures is the high rate of corrosion of steel and copper conductors in the network. Corrosion is caused principally by industrial and salt pollution in the presence of moisture and is due in part to the ageing profile of conductors. It is prominent along the sea coast for up to 10 km inland.

These findings are not unique to Western Power. In evidence to the Victorian Bushfires Royal Commission, SP AusNet noted, among other things, that *the primary issue facing SP AusNet is the increasing age profile and deteriorating performance of steel and copper conductor through failure*.

The biggest contributors to fire starts in AA2 were steel conductors (57% of the network), followed by copper conductors (7% of the network). The investment associated with the business as usual replacement of conductor is included under our asset replacement program. However, given the at risk conductors in extreme and high fire risk areas, we will undertake investment under the bushfire mitigation program to replace additional conductors.

In AA3 2,623 km (or 3.8%) of conductors will be replaced, with 1,073 km replaced under the asset replacement program and 1,550 km replaced under the bushfire mitigation program.

[85] DM 7492577: *Bushfire Management Plan*

This will address 58% of the assets currently identified as *at risk*. The program does not address 100% of the assets at risk due to deliverability constraints.

Address conductor clashing

In AA3 we will invest $60 million, 12% of forecast distribution regulatory compliance expenditure, to reduce the likelihood of conductors clashing. If conductors clash, there is a high probability that hot molten metal particles will be emitted and initiate bushfires. Overhead power lines, given their proximity to one another, can be prone to touching and clashing.

The most common causes of touching or clashing conductors is the use of dissimilar conductor material for phase conductors and the running earth wire which can reduce conductor clearance. The different materials used for conductors (copper, steel, aluminium) have different rates of thermal expansion. During normal operation the conductors sag (expand) as they heat up. If the phase and running earth conductors are of different materials, each will sag at different rates, potentially reducing the clearance between them and increasing the likelihood of clashing.

Other contributors to clashing conductors include:

- weather related-factors, such as high winds (particularly during periods of extreme ambient temperature)
- design issues such as long bays[86] where there is greater risk of conductors coming into contact with one another
- design issues such as short cross-arms, improper tension and changes in the conductor orientation (between horizontal, vertical and vice versa)

Major bushfires were caused by clashing conductors on high voltage distribution lines in Mt Barker in 2000 and Tenterden in 2003, causing loss of life and significant property damage. In both instances the length of the bay (distance between two poles) was considered to be a contributing factor to the conductors clashing. Following these incidents, Energy*Safety* issued an order to us to remediate specific sections of line in the Tenterden area and subsequently developed a plan, in consultation with us, to address conductor clashing in the remainder of the Western Power Network. This required us to develop a strategy that addressed long bays and their contribution to conductor-clashing in high voltage distribution lines.

Address HV conductor clashing

In AA3 we will invest $58 million, 12% of forecast distribution regulatory compliance expenditure, to address HV conductor clashing.

As of June 2011, 15,445 HV long bays were identified as needing to be addressed. 1,895 or 12% of these are located in high or extreme bushfire areas. Depending on the specific circumstances, the most common approaches to mitigate the risk of conductor clashing in long bays involve either:

- installation of wider cross-arms to increase the clearance between conductors at the pole tops
- construction of an additional pole mid-bay to reduce the bay length

In AA3 we will address 8,904 HV long bays (approximately 1,780 per annum).

[86] 'Long bays' are defined as stretches of conductor between supports or poles of greater than 105 metres for running disk angles, longer than 140 metres for in line construction for HV conductors and longer than 30 metres for LV conductors.

Address LV conductor clashing

In AA3 we will invest $2 million, 0.4% of forecast distribution regulatory compliance expenditure, to install LV spreaders in high fire risk areas. There are currently 237,604 LV bays within the Western Power Network. 47,204 or 24% of these are located in high or extreme bushfire areas. We currently install spreaders to address clashing conductors in the LV network. The approach used is as follows:

- bay length less than 30 metres – spreader not required
- bay length between 30 and 60 metres – 1 LV spreader
- bay length between 60 and 90 metres – 2 LV spreaders
- bay length greater than 90 metres – install the required number of LV spreaders to reduce the effective length to no more than 30 meters, or apply other solutions

In the first two years of AA3, we will install spreaders on 16,142 LV bays in high fire risk areas to address all bays greater than 45 metres.

Replace pole tops

In AA3 we will invest $48 million, 10% of forecast distribution regulatory compliance expenditure, to replace pole top assets. Pole top fires are caused by the flow of leakage current across conductive paths in components on high-voltage (HV) pole tops. This generates sufficient localised heat to ignite or char flammable cross-arms (wooden cross-arms) and/or timber pole material. Pole top fires occur most commonly in old and weathered pole tops where older style porcelain insulators are attached to wooden cross-arms.

Pole top fires occur by the combination of a part or all of following factors:

- pole top plant condition (e.g. age and cracks)
- construction type (e.g. wooden poles, wooden cross-arms and certain insulator types)
- climatic condition (rain, especially light rain and foggy conditions)
- environmental conditions (e.g. highly polluted areas such as heavy industrial or road traffic pollution, or coastal areas where high salt contamination exist)

The Energy Networks Association's (ENA) *Technical Report for the mitigation of pole top fires (November 2010)*[87] states that the most cost effective solution to reduce pole top fires over a thirty year lifetime is to replace wood cross-arms with steel replace insulators with low leakage current insulators apply silicone coating to insulators electrically bond all insulator pins tighten loose hardware and wash equipment to remove pollutant build-up.

There are approximately 387,000 cross-arms in the Western Power Network – some poles have HV cross-arms only, some have LV cross-arms only and others have both HV and LV cross-arms. 107,670 or 28% of our cross-arms are situated in extreme or high fire risk areas. The age profile of cross-arms by fire risk area is shown in Figure 61.

[87] Available at: http://www.ena.asn.au/udocs/2010/11/Guidelines-for-the-mitigation-of-pole-top-fires-November-20102.pdf

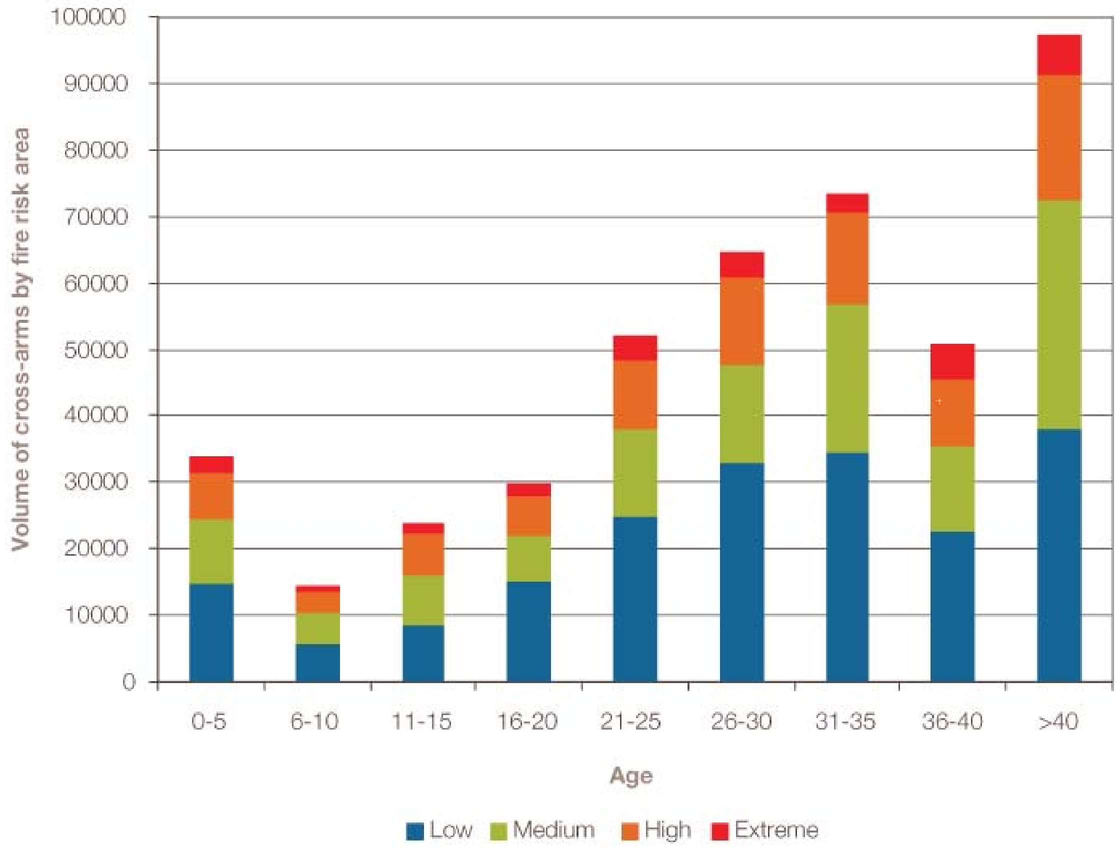

Figure 61: Age profile of cross-arms by fire risk areas

Since 2001, we have used steel cross-arms instead of wood when an HV pole or cross-arm is installed on a new line or when a cross-arm is being replaced on an existing.

In AA3 we will replace 3,140 pole tops per annum. This is the expected required replacement rate that will be identified based on condition from the bundled pole inspection program.

7.3.1.2 Overhead customer service connections

In AA3 we will invest $87 million, 18% of forecast distribution regulatory compliance expenditure, to replace overhead customer service connections. The program will replace all of the identified *at risk* population by the end of 2014/15.

The service connections are being replaced due to an inherent design flaw in the overhead customer service connections that makes them potentially hazardous. The main design flaw is the use of steel preformed helical wires to hold the PVC insulated cables. This design flaw was identified in 2003 following the detailed investigation of an incident that resulted in a double fatality. The preformed wires abrade the PVC insulation of the wires and become live, thereby resulting in an increased potential for electric shock hazard to the public.

Section 25(1) (a) of the *Electricity Act 1945* (the Act) requires us to:

> *... at all times maintain all service apparatus belonging to the network operator which is on the premises of any customer, in a safe and fit condition for supplying electricity*.

We currently have 410,000 overhead customer service connections in the Western Power Network. The inspection following the 2003 incidents established that approximately 300,000 had the potential to cause electric shock and therefore do not comply with the Act. Replacement will significantly reduce the safety risk to the public from electric shocks from overhead customer service connections and ensure compliance with our statutory obligations.

In May 2011, the Authority granted NFIT preapproval[88] of this program for the years 2009/10 to 2011/12. We have replaced approximately 71,300 overhead customer service connections during the AA1 period (July 2006 to June 2009) and will have replaced a further 99,400 by the end of the AA2 period. In AA3 we are continuing the same replacement program to complete the remaining 129,300 of the 300,000 at risk overhead customer service connections by 2014/15.

7.3.1.3 Reliability compliance

In AA3 we will invest $44 million, 9% of forecast distribution regulatory compliance expenditure, to improve compliance with legislative and regulatory obligations to reduce long duration interruptions and improve voltage levels.

We are obliged under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* and the *Electricity Act 1945* to supply customers in a reliable and safe fashion. We can be liable for damages that result from poor power quality.

Improve voltage levels

Section 25(1) (d) of the *Electricity Act 1945* requires us to:

> *... declare the system pressure and/or frequency at which the network operator proposes to supply electricity to the premises of a consumer at the position thereon where the electricity will pass beyond the service apparatus of the network operator, and maintain constantly the said pressure within the limit of ±6% and the said frequency within the limit of ±2½%.*

The system pressure has been declared to be 240 V (single phase). There are currently 1,500 multi-customer LV networks (out of a total 16,500) that are non-compliant with the requirement to maintain a voltage of 240V ±6%. These have largely arisen from the subdivision of land in inner metropolitan and semi-rural areas.

A new program commenced in 2011/12 to manage the voltage on the LV network and, where required, upgrade the LV network to improve compliance with the Act. The program will progressively ramp up over the AA3 period to a level that will be sustained over the following 10-15 years. The works during AA3 will be prioritised based on a number of criteria, including number of complaints, asset age, conductor impedance, feeder lengths and separation between adjoining networks.

Reduce long duration interruptions

Section 12(2) (a) of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (Supply Code) requires that small use customers must not experience more than one twelve hour duration every ten years. Where Western Power is not compliant with this requirement, section 12(3) of the Supply Code requires us to remedy the cause or causes of the interruption or enter into an alternative arrangement with the customer.

The Supply Code has not yet been in place for a ten year period and therefore the total number of customers whose electricity supply does not comply with this requirement is unknown. However, based on the data available since 2006/07, it is estimated that at the end of AA2, there will be 19,500 customers whose electricity supply is non compliant, with an

[88] Available from: http://www.erawa.com.au/3/1154/48/replacement_of_overhead_customer_service_connectio.pm

additional 4,000 customers per annum whose electricity supply will be non compliant during AA3.

Following a pilot program in 2011/12, a program of works will commence in 2012/13 to remedy the cause or causes of the interruptions for 4,000 customers per annum. The remedies are to automate existing switching points and protection devices, install new interconnectors between feeders and add telemetry to existing protection devices.

Whilst this program will ensure that we are compliant with the Supply Code, it is expected to have an immaterial impact on average reliability.

7.3.1.4 Substandard conductor clearance

In AA3 we will invest $30 million, 6% of forecast distribution regulatory compliance expenditure, to address instances of substandard conductor clearance. This is an increase on previous investment levels which is largely driven by the introduction of a new Australian Standard (AS/*NZS 7000:2010 Overhead Line Design – Detailed procedures*) which specifies the minimum clearance between the conductor and the ground.

We have approximately 8,244 roadway locations where the clearance between the conductor and ground does not comply with the new *AS/NZS 7000:2010 Overhead Line Design – Detailed procedures*. The low clearances arise over time with changes to the road surface level and conductor sag and pose a safety risk to the public if vehicles come into contact with the conductors.

A 15 year program has been developed to address the current identified low clearances. Of the 8,244 non compliant clearances:

- 2,813 crossings have a compliance variance of less than 0.2m – these will be addressed through maintenance
- 243 will be rectified during AA2
- 1,470 will be rectified during AA3
- 3,718 will be addressed in later periods

Works during AA3 will be prioritised based on the amount of vehicle traffic using the roadway, the likely height of the vehicles and the variance between the current clearance and required clearance.

7.3.1.5 Power quality compliance

In AA3 we will invest $27 million, 6% of forecast distribution regulatory compliance expenditure, to address customers' power quality complaints and install equipment to monitor power quality. This is a decrease from AA2 investment levels which largely reflects a decreasing trend in the number of power quality complaints from customers.

Power quality issues relate to, for example, voltage fluctuations, voltage flicker and harmonics.

Addressing power quality complaints from customers

We are obliged under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (Supply Code) and the *Electricity Act 1945* to supply customers in a reliable and safe fashion and can be liable for damages that result from poor power quality.

Under section 24 of the Supply Code, we are obliged to investigate any complaints by customers in relation to the quality of their electricity supply impacting on their equipment. If the investigation identifies that we are not compliant with the Supply Code requirement or *Technical Rules*, we are obliged to rectify the non-compliance. This is a continuing program to respond to customer complaints and address non-compliances albeit at lower volumes due to expected lower levels of complaints in AA2.

Installing equipment to monitor power quality

We are obliged under the *Electricity Act 1945* and *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* to monitor the quality of the power supply. 250 monitoring units will be installed during AA3 to be able to monitor and report on the quality of the voltage supply on a sample basis.

7.3.1.6 Conductive poles

In AA3 we will invest $18 million, 4% of forecast distribution regulatory compliance expenditure, to replace conductive poles. This is an increase above AA2 investment levels which reflects a specific program to address a non compliance in the Kambalda area.

Conductive poles that do not comply with the step and touch potential requirements as set out in the ENA Industry guideline for the inspection, assessment and maintenance of overhead power lines and the *Technical Rules*, pose an electric shock hazard.

Most conductive poles have already been removed from the Western Power Network. However approximately 553 conductive (metal) poles in the Kambalda area have recently been identified. We will invest in a one off program to replace the metal poles with alternatives, or to underground them by the end of 2014/15.

7.3.1.7 LV network upgrades

In AA3 we will invest $14 million, 3% of forecast distribution regulatory compliance expenditure, on targeted LV network upgrades. Clause 2.5.4.4 of the *Technical Rules* states that the number of customers in a switchable feeder section is to be limited to 860, where there is not an interconnector. Feeders that were designed prior to the introduction of this requirement will become non compliant as residential development and building construction activity increases the number of buildings, and thereby customers, on feeders.

The program is to commence in 2012/13, following scoping, planning and design in 2011/12. It is forecast that there will be one non compliant feeder per annum that will need to be addressed during AA3 and that the program will continue for approximately ten years, after which all new land development releases will have been designed to comply with the rule.

7.3.1.8 URD pillars

In AA3 we will invest $10 million, 2% of forecast distribution regulatory compliance expenditure, to replace underground residential distribution (URD) pillars. This is an increase on AA2 investment levels which largely reflects the increase in the URD pillar population.

Section 25(1) (a) of the *Electricity Act 1945* requires us to:

> *... at all times maintain all service apparatus belonging to the network operator which is on the premises of any customer, in a safe and fit condition for supplying electricity.*

There currently exists a risk of electric shock from damaged and aged underground pillars. The underground pillar project continues a program commenced during AA2 to address hazards associated with asbestos and continues an ongoing project to replace underground pillars damaged, for example, as a result of vehicle collision.

7.3.1.9 Other

The following activities are individually less than $10 million per program over the AA3 period or below 2% of forecast distribution regulatory compliance expenditure.

- Pole top switches replacement ($10 million) – following a near fatal incident in 2002, we committed to replace all pole top switches that fail to meet Australian industry safety standards or fail in service. In AA3 we will continue the program replacing approximately 249 pole top switches per annum as failures occur (approximately 152 per year) and as routine inspections identify non compliant pole top switches (approximately 97 per year).
- Streetlight switch wire replacement ($7 million) – this program has been reprioritised as it has been identified as one of our highest public safety risks. As streetlight switch wires age, corrode and sag there is a risk of electric shock if contact is made with them, such as by a vehicle or machinery. There is 3,370 km of streetlight switch wire that needs to be replaced. Our current rate of replacement would require 15 years to complete. In AA3 we will increase our replacement rate to complete the program over an 8 year period.
- Underrated stay wires replacement ($4 million) – the ENA's *DOC 017-2008 Industry Guideline for the inspection assessment and maintenance of overhead power lines*[89] sets out a number of requirements related to poles to ensure that the poles do not pose a safety risk to the public through failure or electric shocks. This program replaces stay wires that are either underrated, providing insufficient structural support for the overhead network or missing. In AA3 we will prioritise replacement of stay wires providing insufficient support, replacing approximately 2,900 stay wires.
- Distribution substation safety and security ($2.2 million) – The ENA have released a national, industry wide guideline for the prevention of unauthorised access to electricity assets (see section 6.4.1.4). The guidelines were enhanced due to the threat of terrorism and due to the increased number of incidents involving unauthorised entry around Australia, some of which resulted in fatalities. There is an ongoing work program to increase security measures and prevent unauthorised access to our substations. This program will elevate security standards to a level that first meet, and then maintain compliance appropriately with, these obligations.
- Reinforce transformer poles ($2.1 million) – the ENA's *Guidelines for the inspection, assessment and maintenance of overhead power lines* sets out a number of requirements related to poles to ensure that the poles do not pose a safety risk to the public through failure or electric shocks. Early methods for reinforcing poles with transformer mounted on them have been found to provide insufficient support for these poles with the extra load of the transformer. To reduce the high risk that these poles will fail, 582 poles with transformers mounted on them and identified as having insufficient reinforcement will be reinforced by the end of 2014/15.
- Cattle care ($1.7 million) – this program aims to prevent the ingestion of toxins by cattle that exist in soil surrounding chemically treated wood distribution poles. Collars are fitted around the base of distribution poles, on the request of farmers, to prevent the growth and consumption of grass. Applications are made for these collars by farmers through the Agriculture Department of WA. Volumes have been determined based on the current backlog of applications and estimated number of new applications that will be received from farmers. It is expected that 319 applications will be received each year, totalling approximately 1,595 collars to be

[89] Available at: http://infostore.saiglobal.com/store/Details.aspx?productID=1021045

installed during the AA3 period. A trial is currently being undertaken of a rubber collar which is much less costly and less resource intense to install than a concrete collar. The trial is still in progress to determine if the rubber collar offers the same protection as the concrete collar.

- Install stay wire insulation ($1.4 million) – this is an ongoing program to install stay wire insulators where they are missing (as a result of unknown or accidental causes). There is a significant safety risk where insulators are missing. There are currently in the order of 3,246 stay wires lacking insulators. As part of this ongoing activity 1,770 stay insulators will be retrofitted in AA3. These have been prioritised to address the highest risk areas first and where possible to seek optimisation by scheduling insulator retrofits concurrent with other work.
- Distribution river crossings ($1.2 million) – the January 2003 *Code of Practice* – power line crossing of navigable waterways in Western Australia sets out minimum conductor clearances over navigable waterways. The clearances are required to reduce the safety risk associated with boat masts making contact with conductors. All river crossings have been assessed and there are 5 non compliant crossings remaining to be addressed by the end of 2014/15.

7.4 Improvement in service

In AA3 we will invest $33 million to improve service levels in the distribution network. This represents 1% of forecast distribution network capital expenditure.

We deliver these projects and programs through two distinct categories:

- *reliability driven* – targeted programs to improve the reliability performance and security of the network to achieve the minimum service standard benchmarks outlined in the Access Arrangement
- *SCADA and communications* – to enable the real-time monitoring and automation of our transmission assets

We have forecast a minimal amount of reliability driven expenditure in AA3. Should we identify any individual reliability improvement projects that will have a measurable effect on average service performance during AA3, we will pursue these only where the service incentive rates under the service standard adjustment mechanism outweigh the cost.

7.4.1 Reliability driven

In AA3 we will invest $3.3 million, 0.1% of forecast distribution network capital expenditure, on distribution reliability driven projects (see Table 56).

We will invest in the research and development of new technologies and standards to investigate, implement and integrate innovative solutions to provide alternate and cost-effective options to achieve improvements in network performance.

Table 56: AA3 distribution reliability driven expenditure ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Reliability driven	0.6	0.6	0.7	0.7	0.7	3.3

In the AA3 period, we will maintain service levels at expected levels of performance. This means we will only invest in targeted service improvement activities where the benefit of delivering the service improvements outweighs the costs. The benefits are estimated based on the service standard adjustment mechanism financial incentives rates, which have been developed using the value that customers place on reliability. Growth driven investment and normal maintenance activities will contribute towards maintaining performance. This category of expenditure is broader than reliability. It is service driven, covering reliability, power quality and measures of momentary interruptions (MAIFI) which are not captured as a service standard benchmark or in the SAIDI measure.

Figure 62 shows our distribution reliability driven expenditure over the AA1 to AA3 period. The expenditure in 2011/12 is targeting some of our worst served customers and is not expected to have an improvement on average reliability.

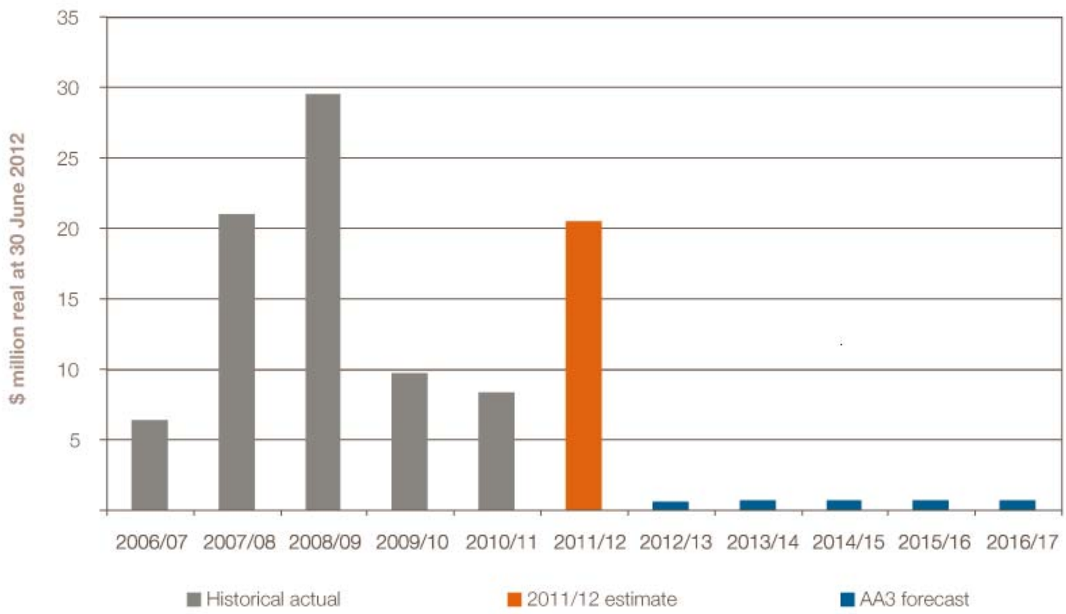

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Figure 62: Distribution reliability driven historical and forecast capital expenditure

New facilities investment test

New facilities investments in distribution reliability driven are only undertaken where section 6.52(b) (iii) of the Access Code is met, or the anticipated benefits awarded under the service standard adjustment mechanism outweigh the cost. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted service.*

AA3 distribution reliability driven expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. This investment will enable future opportunities through innovation and new technology to efficiently minimise costs while achieving the service standard benchmarks. In the AA3 period, we will also rely on the financial incentive rates under the service standard adjustment mechanisms to determine the point at which the customer value placed on a desired service level outweighs the delivery cost.

REGULATORY OBLIGATIONS

We are obliged, under sections 9 and 10 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (the Supply Code) to, as far as is reasonably practicable:

- ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum (section 9)
- reduce the effect of any interruption on a customer (section 10 (1))

As operational requirements evolve and new technologies become available we will evaluate when it is more efficient to invest in capital and reduce operating expenditure. This research and technology investigation will focus on leveraging the potential of existing installed equipment and undertaking benefits analysis to provide the business with options to deliver future reliability outcomes. The suite of pilot programs forecast for the AA3 period target power quality initiatives and reliability measures that are not included as part of our service standard benchmarks.

Pilot schemes under development or new technology available for testing include:

- voltage regulator telemetry solution – addition of remote indication, monitoring and control of voltage regulators to provide visibility, override and analogue measurements for the network operations control centre. Benefits include improved management of HV voltage levels and equipment during normal network operation and during fault conditions
- measurement of momentary average interruption frequency index (MAIFI) – transitioning us to good electricity industry practice given the majority of our peers are currently measuring and managing MAIFI as a service standard benchmark
- integrated volt/VAR Control (IVVC) – continuously analyses and controls load tap changers, capacitor banks and voltage regulators to autonomously manage system power factor and voltage. This allows us to potentially flatten a feeder's voltage profile, lower average voltages and maintain unity power factor to eliminate technical losses
- Schneider Nulec advanced controller (ADVC2) – Schneider Nulec Reclosers provide protection, remote monitoring and control of the HV distribution network. Pending the outcome of the Recloser Tender Evaluation, there is an advanced controller available that could provide improved functionality, including HV power quality measurements and ethernet connectivity
- optical faraday fault indicators and overhead fault indicators – fault indicators are able to assist the network operations control centre remotely identify the location of a fault on the HV distribution network. Pending investigation and a cost/benefit analysis, we will develop standards and prepare a pilot program

The forecast has been developed using historical investment on similar pilot programs (planning, scoping and design) that we have delivered.

7.4.2 SCADA and communications

In AA3 we will invest $30 million, 1% of forecast distribution network capital expenditure, in distribution Supervisory Control and Data Acquisition (SCADA) and communications equipment.

The SCADA and communications network supports the operation and control, management and planning of primary network infrastructure. Without these systems we cannot operate, monitor and collect network data for the Western Power Network.

Communications assets range from physical communication mediums, for example optical fibre cable and wireless systems, to terminal equipment and supporting network management equipment, for example multiplexers and digital network management systems. SCADA assets provide a direct interface to the network elements to which they are connected – these include remote terminal units at substations, master stations and the central control centre.

The magnitude and timing of distribution SCADA and communications expenditure is largely driven by:

- performance requirements of the expanding network
- bushfire risk mitigation strategies to remotely control and configure feeder protection during fire risk conditions
- compliance with regulatory and legislative obligations
- short lifecycles of IT and telecommunications hardware and software
- third party actions with regard to communications infrastructure
- serviceability and availability of spares

Investment in this category was deferred from AA2 but can no longer be delayed due to a lack of manufacturer support and spare parts for some assets. We are currently facing critical obsolescence issues on many SCADA and communications assets where extending the life of the assets is no longer feasible due to availability of parts and support. As shown in Figure 63, we began these critical upgrades and replacement of SCADA and communications assets from late 2010/11.

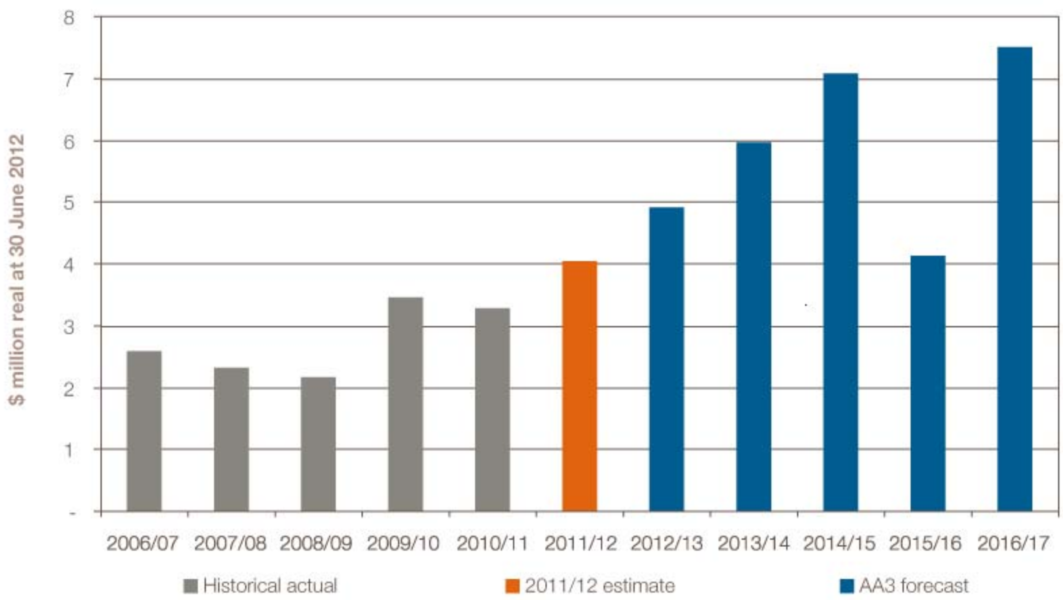

Figure 63: Distribution SCADA and communications historical and forecast capital expenditure

New facilities investment test

New facilities investments in distribution SCADA and communications are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services.*

AA3 distribution SCADA and communications expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. Without this investment, the safety and reliability of our network is at risk because of the less than optimal remote visibility and control required to effectively manage distribution network assets. In addition, we would be at risk of not meeting service standard benchmarks and therefore would fail to provide acceptable levels of service to our customers.

AA3 distribution SCADA and communications expenditure has been assessed as efficiently minimising costs under section 6.52(a) of the Access Code as described in chapter 8 of the AAI. We invest in common SCADA and communications assets and systems across many projects in a centralised model to realise efficiencies of scale and scope when digital control, monitoring and communications functions are required for distribution primary network assets.

REGULATORY OBLIGATIONS

Investment in distribution SCADA and communications enables us to meet regulatory requirements related to continuous network control and monitoring, including:

- meet power system SCADA and communications standards (for example *Technical Rules* sections including: 3.3.2, 3.3.4.3, 3.6.9 and 5.10.1)
- aid in meeting distribution aspects of power system performance standards (*Technical Rules* sections 2.2, 2.3.9, 2.5.4.2, 3.2.1, 3.3 and 5.3.1) and *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*
- manage our communications facilities to comply with the *Telecommunications Act 2004* and to manage and meet the related obligations.
- discharge our responsibility to provide operational co-ordination of the power system and *Wholesale Electricity Market (WEM) Rules* (Wholesale Electricity Market Rules sections 3.2.8, 6.13.1 and 7.13)

It should be noted that the AA3 expenditure does not include a forecast for third party actions, as none have been identified. However, in AA2 third party actions required us to invest $0.6 million when Telstra closed down its CBD digital metropolitan services and we needed to migrate services to other communications links.

A breakdown of AA3 forecast distribution SCADA and communications expenditure by activity is shown in Table 57 and Figure 64.

Table 57: AA3 distribution SCADA and communications expenditure by activity ($ million real at 30 June 2012)

Activity	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Asset replacement	3.1	3.3	5.1	3.8	7.2	22.5
Core infrastructure growth	0.5	1.4	0.8	-	-	2.7
Performance and regulatory	0.9	0.9	0.9	-	-	2.7
Improvement in service	0.4	0.4	0.3	0.3	0.3	1.7
SCADA and communications total	**4.9**	**6.0**	**7.1**	**4.1**	**7.5**	**29.6**

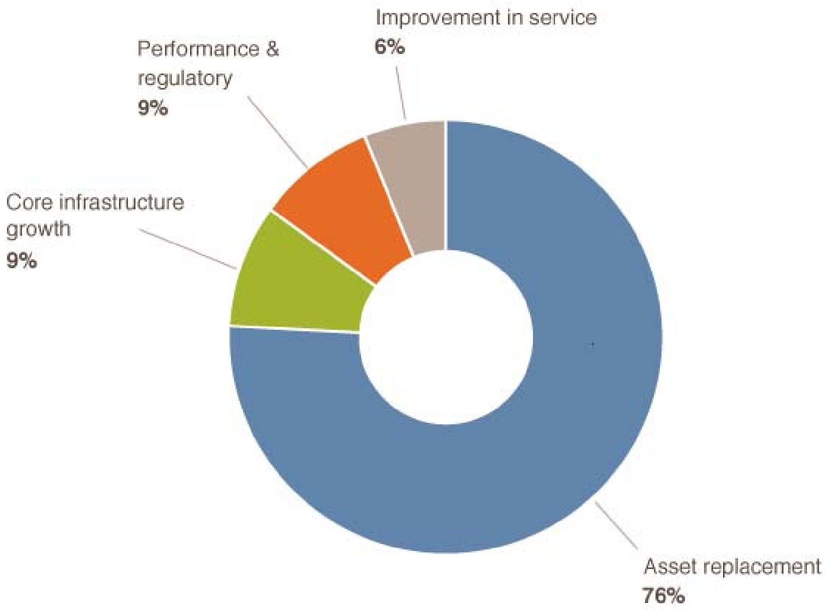

Figure 64: AA3 distribution SCADA and communications expenditure by activity

Each of these activities is discussed in the following sections.

7.4.2.1 Asset replacement

In AA3 we will invest $23 million, 76% of forecast distribution SCADA and communications expenditure, to replace critical distribution SCADA and communications systems infrastructure. This is an increase from AA investment levels which largely reflects the deferral of works during the AA2 period. It is now necessary to replace these assets to address issues of obsolescence and to halt increased operating costs associated with maintaining assets that have a high probability of failure.

SCADA and communications assets are replaced when they fail to meet their intended functionality, have reached the end of their support and product life cycle, or have reached their capacity limitations. Replacement cycles typically vary between 3 and 15 years for these types of assets.

Asset replacement expenditure forecasts are derived from historical replacement levels, adjusting where necessary for asset age and condition as captured annually in the secondary systems management plan. Forecasts are costed using standard designs and recent project costs.

The main replacement programs in the AA3 period are as follows:

- ENMAC[90] upgrades – the AA2 work program addressed the immediate concerns in cyber and physical securities. The AA3 work program will enable the continuation of

[90] The name ENMAC is a GE trademark/brand name from the generic term 'Electricity Network Management and Control' system. It is a business critical system that provides visibility and control of the distribution network and the management of customer outages.

incremental upgrades, reinforcement of system cyber security and further enhancement of the power flow application Distribution Power Analysis

- CBD SCADA replacement – migrate the CBD RTU from a low-speed proprietary serial communications protocol to an open protocol over a higher speed ethernet based optical communications backbone. The first stage of the transformation requires the replacement of the existing RTU with Goanna GT31 devices. This will ensure we maintain visibility and control of the CBD region to meet requirements in section 2.5.4.2 of the *Technical Rules*[91] and retain visibility and control for operators to detect and rectify faults to support performance requirements
- Tait data radio replacement – replace existing 150 MHz Tait base and remote radios installed throughout the Western Power Network that form our country distribution automation network. Initially installed as part of the foundational Rural Power Improvement Program (RPIP) in 04/05 and 05/06, to provide remote control and visibility of key distribution pole-top devices, these radio assets will be reaching expected asset life during AA3. With increases of unit failure and reducing numbers of available spares and manufacturer support, we are exposed to an increasing risk of extended and unacceptable communications service outages to critical distribution automation functions
- MR450 radio replacement – approximately 150 MR450 devices will require asset replacement or life extension late in AA3. These data radio devices provide a communications medium for control and visibility of remote pole-top distribution automation devices

Other asset replacement programs are minor compared to these four programs.

7.4.2.2 Core infrastructure growth

In AA3 we will invest $2.7 million, 9% of forecast distribution SCADA and communications expenditure, on core SCADA and communications infrastructure to meet growth needs.

Costs for infrastructure growth are generally captured under the capacity expansion projects which trigger them, except where works are of a sufficient scale, or where these works lead to ‘orphaned’ or incomplete systems, and it becomes more efficient to aggregate growth project requirements into a ‘core infrastructure’ SCADA project.

Core infrastructure needs to be constantly extended to support demand for increasing bandwidth applications and to ensure the core bearer networks can maintain redundancy and high levels of availability systems as required by the *Technical Rules* and to meet service standards.

In AA3 this activity will focus on communications circuits for the distribution automation expansion stage 2 which is part of our migration strategy to remove the data concentrators from the CBD system and create a redundant network directly from East Perth to the remote sites. Existing data concentrators for metro and country are currently being removed as these assets no longer serve their purpose since the ENMAC system can now communicate directly with distribution automation devices.

This program works in tandem with the provision of distribution automation devices that maintain our capability to meet service standard benchmarks and to maintain overall distribution network safety and reliability service levels.

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[91] Section 2.5.4.2 of the *Technical Rules* requires *Distribution feeders in the Perth CBD Zone must be designed so that in the event of an unplanned loss of supply due to the failure of equipment on a high voltage distribution system, the Network Service Provider can use remotely controlled switching to restore supply to those sections of the distribution feeder not directly affected by the fault*.

7.4.2.3 Performance and regulatory

In AA3 we will invest $2.7 million, 9% of forecast distribution SCADA and communications expenditure, to ensure compliance with regulatory and performance requirements for SCADA and communications equipment.

In AA2 for example, the revision of the AS/NZS1170.2 standard imposed more stringent tower loading requirements. This required reinforcement of our communications structures found to be non-compliant. Stage 1 of the communication tower reinforcement project started in 2006/07 and was completed in 2009/10. The bulk of AA3 distribution SCADA and communications performance and regulatory compliance expenditure is needed for stage 2 of this project. Given no further changes to the standards, the project is expected to be completed within AA3.

7.4.2.4 Improvement in service

In AA3 we will invest $1.7 million, 6% of forecast distribution SCADA and communications expenditure, to improve SCADA and communications service to meet growth needs and maintain current levels of service.

The intrinsic features of SCADA and communications technology are consistent and rapid change with regular step changes. This investment provides for continuous service improvements and enhancements to SCADA and communication assets to ensure efficient utilisation of systems and subsystems, reduce untimely or unplanned step changes and in some case the extension of the asset life.

The AA3 improvements include ENMAC DPA (distribution power analysis enhancements stage 2 and the implementation of the ENMAC master station network model manager.

8 Corporate capital expenditure

Western Power's corporate capital expenditure funds the refurbishment and maintenance of office and depot accommodation, the purchase of property, plant and equipment and IT infrastructure (excluding SCADA systems). In AA3 we will spend $301 million on corporate capital expenditure through two distinct categories:

- IT – new, replacement or upgrades to the IT hardware and software required to collect, manage and monitor asset and performance data in order to maintain the safe and reliable operation of the network
- business support – needed to achieve compliance with various regulatory and legislative obligations, to support the works program and to increase efficiency in the workplace through space optimisation and better functioning facilities

8.1.1 IT capital expenditure

In AA3 we will invest $174 million on IT infrastructure. This represents 58% of forecast corporate capital expenditure. Western Power must maintain robust IT infrastructure, systems and applications to efficiently provide its regulated network services. The key drivers of our forecast IT expenditure are the:

- condition of existing IT assets
- need to meet and maintain current network standards

Our investment in IT infrastructure will deliver sufficient asset replacement to address the age and condition of existing IT assets and the risks faced from a lack of vendor support for aged assets and applications. It will also provide capacity upgrades to meet business user consumption levels and new technology to meet the business' infrastructure requirements.

Our IT expenditure allows us to maintain network support and market interfaces and supports the realisation of enterprise efficiencies by improving the productivity of our labour force. Our AA3 IT expenditure comprises:

- enterprise systems – comprises transformation initiatives involving the design, sourcing and execution of major enterprise level information systems implementation projects
- IT infrastructure – end-of-life IT hardware and software asset replacement, capacity upgrades to meet organic growth and implementation of new technology to improve operations
- business as usual – small enhancements to business systems

Our forecast AA3 IT expenditure has been derived from our Enterprise Systems Asset Management Plan (ESAMP), see Appendix N: Enterprise Systems Asset Management Plan. The ESAMP sets out the system management plans for the key enterprise systems that we rely on to deliver our regulated network services.

The enterprise systems capital expenditure is inherently lumpy, due to the addition at irregular intervals of new IT systems to the asset base. By comparison, our general IT infrastructure and business as usual capital expenditure remains relatively stable over time.

Our treatment of IT infrastructure capital expenditure has changed during the AA2 period. Prior to 2010/11, IT infrastructure expenditure provided IT infrastructure support both internally within our business and to the disaggregated entities of Verve and Synergy. The IT infrastructure costs relating to Western Power were charged back to the regulated business through business unit charges and the costs relating to the disaggregated entities were recovered from them. Since 2010/11 we stopped holding capital assets to provide IT infrastructure to the disaggregated entities. As a result, we no longer separate our IT infrastructure investment from our regulated business expenditure. The historical investment, including the impact of this change in the allocation method for our IT expenditure in 2010/11, is shown in Figure 65. The peak in expenditure in 2007/08 was a result of expenditure to migrate some of our core IT systems including Ellipse and the trouble call system, following disaggregation of Western Power Corporation into Western Power, Verve, Synergy and Horizon Power.

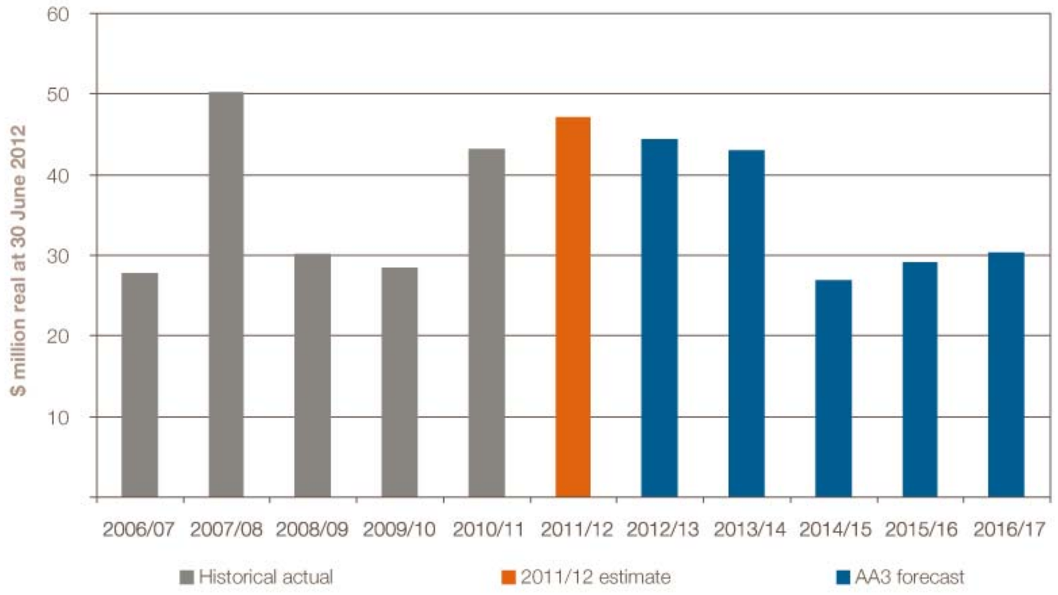

Figure 65: IT historical and forecast capital expenditure

The forecast reduction in investment from 2014/15 reflects the completion of a number of enterprise systems transformation initiatives in 2013/14.

New facilities investment test

New facilities investments in IT assets are only undertaken where section 6.52(b) (ii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.*

AA3 IT capital expenditure has been assessed as meeting section 6.52(b) (iii) of the Access Code. This investment is required to ensure our ongoing provision of covered services. Our IT capital expenditure over AA3 is driven by:

- requirements to satisfy regulatory and legislative obligations within metering and document management
- our development of more efficient office-to-field and field-to-office systems and processes to streamline the execution of work during AA3
- the enhancement of our works program governance and delivery model to further improve our selection and execution of works and the realisation of benefits

- improvement in the accuracy, currency and availability of information about our assets to support more effective network investment decisions – to do the right thing at the right time
- the need to reduce the increasing costs of maintaining old legacy systems by introduction of industry standard systems

AA3 IT capital expenditure has been assessed as efficiently minimising costs. We have forecast a program of work that constrains expenditure below demand level to force prioritisation of candidate projects to ensure efficient use of the available capital. We have also adjusted our IT infrastructure expenditure for growth in the number of users and new technology investment, but then offset costs by the expected unit cost reduction of larger volumes of IT assets.

REGULATORY OBLIGATIONS

Investment in IT enables us to meet regulatory requirements related to network operation and control, monitoring, reporting and data analysis to maintain the safety or reliability of the covered network and its ability to provide contracted services, including:

- *Electricity Networks Access Code 2004* includes provisions for service performance reporting which requires collection and storage of performance data in IT systems for example section 11.3:

The Authority may, acting reasonably, request a "service standard performance report" from a service provider for the purposes of monitoring the service provider's actual service standard performance and the service provider must provide the Authority with a service standard performance report within the time specified by the Authority in its request, which time must not be less than 20 business days.

- *Electricity Industry Metering Code 2005* includes provisions for a metering database which requires IT systems for example section 4.1(1):

A network operator must establish, maintain and administer a "metering database" containing, for each metering point on its network:

(a) standing data for the metering point; and

(b) energy data for the metering point, being:

(i) if the metering point has an accumulation meter — accumulated energy data; or

(ii) if the metering point has an interval meter — interval energy data.

- *Code of Conduct for the Supply of Electricity to Small Use Customers 2008** includes provisions for streetlight reporting which requires collection and storage of performance data in IT systems for example, section *13.9(1) Timely repair of faulty street lights:*

A distributor must keep a record of –

(a) the number of street lights reported faulty each month;

(b) the number of street lights not repaired before the agreed date;

(c) the total number of street lights; and

(d) the average number of days to repair faulty street lights.

* Available at http://www.erawa.com.au/cproot/6425/2/20080304%20Code%20of%20Conduct%20for%20the%20Supply%20of%20Electricity%20to%20Small%20Use%20Customers%202008%20-%20Gazetted%2026%20February%202008.pdf

A breakdown of AA3 forecast IT expenditure by activity is shown in Table 58 and Figure 66.

Table 58: AA3 IT expenditure by activity ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of total IT
Enterprise systems	26.5	24.6	7.9	8.8	8.4	76.2	43.9%
IT infrastructure	10.5	10.8	11.2	11.3	11.4	55.2	31.7%
Business as usual	7.4	7.6	7.8	9.1	10.5	42.4	24.4%
IT total	**44.4**	**43.0**	**26.9**	**29.2**	**30.3**	**173.8**	**100.0%**

Each of these activities is discussed in the following sections.

8.1.1.1 Enterprise systems

In AA3 we will invest $76 million on our enterprise systems transformation initiatives to improve our operations and increase our IT systems' efficiency. The IT transformation journey commenced in AA2 and continues during AA3. Over AA3 the enterprise systems will:

- develop and maintain asset and works management systems to meet specific corporate targets such as works program delivery, including automation of the works program governance model described in chapter 4 of the AAI
- develop and maintain metering management systems to enable compliance against the Electricity Industry Metering Code 2005
- maintain core systems at vendor supported levels and infrastructure within industry accepted tolerances for age and capacity
- complete initiatives to improve business performance and reduce business risk from legacy or outdated systems
- complete initiatives that respond to specific external pressures from our shareholder, board, regulators and customer groups

8.1.1.2 IT infrastructure

In AA3 we will invest $55 million to replace IT infrastructure. Our IT infrastructure forecasts are based on the age and replacement cost of our existing IT asset base, with asset replacement set in accordance with an average four year asset life cycle. IT infrastructure includes items such as desktop computers, operating system and desk top applications.

Our IT infrastructure provides for growth in the number of users and new technology investment, with costs offset by the expected unit cost reduction of IT assets.

8.1.1.3 Business as usual

In AA3 we will invest $42 million on our business as usual capital expenditure to undertake ongoing minor business system enhancements. Business as usual capital expenditure will continually improve our functionality, allow our business to adapt to changed processes and ensure compliance with incremental changes in network, energy market and corporate obligations.

Business cases are submitted annually to the Business Reference Group (steering committee) to access funds and IT resources for undertaking these minor enhancements. Our business as usual forecasts are deliberately constrained below expected demand to force the prioritisation of candidate projects and avoid excessive tactical spend.

8.1.2 Business Support

In AA3 we will spend $128 million, 42% of forecast corporate capital expenditure on our business support capital program. Capital expenditure within business support is needed:

- because the current standard of our office and depot accommodation requires significant improvement to achieve compliance with regulatory and legislative obligations including: *Building Code of Australia*[92] (BCA), *Disability Discrimination*

[92] For example: (1) Fire hydrant, booster pumps and fire hose reels code compliance under AS2419, AS2441 & AS2941 of Building Code of Australia 2007; (2) Fire sprinkler services code compliance under AS2118 of Building Code of Australia 2007; and (3) Fire indication panel code compliance under AS1670 of Building Code of Australia 2007. Available at: http://www.abcb.gov.au/

Act 1992 (DDA)[93] and Premises Standards, *Occupational Safety and Health Act 1984* (OHS) (including *NOHSC 2005 Code of Practice for Asbestos Removal*)[94] and the *Environmental Protection Act 1986* (EPA)

- for the purchase of safety and communications equipment and to undertake fire safety upgrades to the East Perth Control Centre to meet safety regulation and legislative requirements
- to construct a bund facility[95] to ease pressure on our current transformer storage facilities in Jandakot

Figure 66 shows that our historical business support capital expenditure for the AA1 to AA3 periods. The lumpiness of the expenditure profile reflects the staged works associated with our Project Vista – continuing investment in refurbishing our head office and depot locations to comply with current building codes and remove asbestos. Expenditure in our other activities of business support capital expenditure is relatively constant over time.

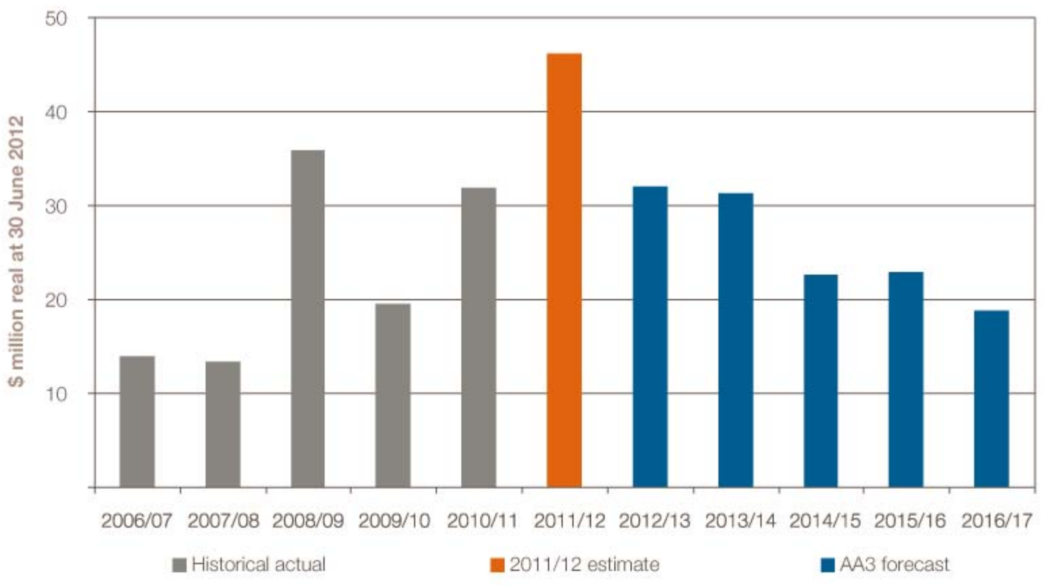

Figure 66: Business support historical and forecast capital expenditure

A breakdown of AA3 forecast business support capital expenditure by activity is shown in Table 59.

[93] Available at: http://www.comlaw.gov.au/Series/C2004A04426
[94] Available at: http://industry.flexiblelearning.net.au/example_royal_perth/toolbox_601/shared/documents/OSH_Act_1984.pdf
[95] The bund facility will provide oil containment for the Jandakot transformer storage facility. Bunds are designed to capture and contain oil leaks and spills so that oil does not enter the environment.

Table 59: AA3 business support capital expenditure by activity ($ million real at 30 June 2012)

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% of business support total
Corporate real estate	26.1	25.3	16.6	16.9	12.8	97.8	76.7%
Property, plant and equipment	6.0	6.0	6.0	6.0	6.0	29.8	23.3%
Business support total	**32.1**	**31.3**	**22.6**	**22.9**	**18.8**	**127.6**	**100.0%**

Each of these activities is discussed in the following sections.

New facilities investment test

New facilities investments in corporate assets are only undertaken where section 6.52(b) (iii) of the Access Code is met. Section 6.52(b) (iii) of the Access Code requires that *the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted services.*

AA3 corporate capital expenditure has been assessed as meeting section 6.52(b) (iii) under the Access Code. This investment is required to ensure compliance of our office and depot accommodation and infrastructure with our regulatory obligations including BCA, DDA and Premises Standards, OHS and EPA. In addition, it increases efficiency in the workplace through space optimisation, increased seating capacity and better functioning facilities and amenities and ensures a safe working environment.

We efficiently minimise costs:

- through the competitive tender processes used to secure services to undertake our corporate real estate capital program
- through our prioritisation of works in accordance with our corporate risk assessment criteria, which assesses the consequence and risk to our business of compliance failures in relation to significant regulatory and legislative obligations

8.1.2.1 Corporate real estate

In AA3 we will invest $98 million, 77% of corporate capital expenditure on essential works and upgrades to our real estate and property portfolio.

Continuing our AA2 program of work, this work is required to comply with our regulatory obligations including BCA, DDA and the Premises Standards, OHS and the EPA.

The corporate risk to our business from not undertaking these works includes fines from corporate bodies due to non-compliance with legislative requirements and the potential for litigation due to our inability to provide a safe working environment for staff and contractors.

The majority of our real estate and property portfolio is inadequate and outdated and is failing to meet the current demands of our business. In most cases these assets are at or nearing the end of their useful life and require refurbishment, upgrades or replacement to meet legislative obligations. Our AA3 capital expenditure comprises:

- refurbishments to our head office and our major metropolitan depot accommodation at Jandakot, Kewdale, Stirling (Balcatta), Mount Claremont and Mandurah as part of our Vista project
- improvement works and refurbishments at the East Perth Control Centre

- the design, construction and refurbishment of facilities at selected country depots and reactive maintenance provisions for all depots

Project Vista

Project Vista continues to focus on the removal of asbestos, essential works to base building systems and the achievement of improved corporate accommodation standards. Limpet asbestos in our head office needs to be removed urgently due to the deterioration of its encapsulation. Upgrades to essential base building systems (fire, mechanical, heating ventilation and air conditioning or HVAC, electrical and hydraulic) are necessary to comply with current building codes and will form part of the construction phase when each floor is refurbished.

Greenstar accreditation has been incorporated as part of the design standards for refurbished and newly constructed facilities. Environmentally sustainable design principles ensure more efficient operation of our corporate accommodation assets by reducing our energy consumption and reducing annual repairs and maintenance costs, while creating a healthier environment for staff.

Our forecasts for the refurbishment of the remaining floors at head office have been refined through analysis of the actual spend on floors refurbished in AA2. Forecasts for depot sites have been informed by historical trends and estimates from quantity surveyors.

East Perth Control Centre

Specific works that are required during AA3 at the East Perth control centre include the air conditioning's chilled water piping and pump, improvements to fire safety and perimeter security and refurbishments to the foyer. The fire safety upgrades are aligned with the extensions to the control centre building which are required to accommodate increased staff levels. The fire safety upgrades are required to comply with the latest BCA.

Depot works

New depots at Busselton (Vasse) and Jerramungup are required to be constructed during AA3 as additional capacity is needed to accommodate the increased capital works program. The existing depots cannot be expanded, as these sites are either leased (Jerramungup) or connected to sub-stations (Busselton). Land to construct these depots was purchased in 2008/09.

There is also a critical requirement to construct a bund facility[96] to ease pressure on our current transformer storage facilities in Jandakot. The Jandakot depot site is located on a Priority 1 water mound, which is the main household water aquifer for the area. The bund facility is required because our current storage facilities cannot accommodate additional transformers without creating significant environmental risk.

8.1.2.2 Property, plant and equipment

In AA3 we will invest $30 million on property, plant and equipment, 23% of corporate capital expenditure. Property, plant and equipment expenditure includes the purchase of capital items to support and maintain office and depot accommodation and equipment and tool purchases.

Equipment and tools are required for construction, commissioning and maintenance functions and the labour costs for the management of the capital works processes and programs. In AA3 forecasts of expenditure on property, plant and equipment are based on an assumed continuation of the internal resourcing levels forecast for 2010/11.

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[96] The bund facility will provide oil containment for the Jandakot transformer storage facility. Bunds are designed to capture and contain oil leaks and spills so that oil does not enter the environment.