Capital and operating expenditure 2009/10 to 2011/12

westernpower

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Foreword

This report provides the detailed justification for Western Power's forecast capital and operating expenditures for the 3 year regulatory term commencing 1 July 2009.

The expenditure plans have been developed using a "bottom up" approach in response to a range of key business drivers, based on sound analysis of needs and supporting justification, followed by review by an independent expert consultant.

Consideration was given to the current and assessed future resourcing capabilities available to Western Power, utilising a range of internal and external resources, to produce the enclosed program of capital and operating expenditure which is practically achievable.

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Expenditure summary

This document sets out the capital and operating expenditure program that is forecast for the regulatory period from July 2009 to June 2012. The forecast expenditures cover all transmission and distribution assets comprising the South West interconnected system. Also included are the expenditures for non-network assets such as land assets not related to the system, and business support costs.

This section provides a summary of the forecast expenditures.

Transmission network

Western Power proposes to invest $2.19B (real 30 June 2009)[1] during the three year regulatory period on its transmission asset base.

Table E1 shows that transmission network capital expenditure (Capex) is forecast to increase from an average of $356M per annum in the 2006/07 to 2008/09 period to an average of $731M per annum over the next regulatory period. This represents an increase of 105%. Of this, 81% is driven by growth related work. The balance is related to enhanced asset replacement practices, network reliability improvements, changing standards, and compliance with changing safety, statutory and environmental requirements. This additional expenditure is collectively categorised as 'non-growth related' in Table E1.

Table E1 – Transmission capital expenditures, actual and forecast ($M)

Category	06/07	07/08	08/09	09/10	10/11	11/12
Network:						
- Growth related	268.0	275.5	375.6	589.2	726.8	463.9
- Non-growth related	29.2	26.8	52.5	95.6	95.4	100.8
Estimating risk factor	0	0	0	24.0	28.8	19.8
Business support cost	9.7	14.7	15.5	21.2	18.8	9.3
Total Capex	306.9	317.0	443.6	730.0	869.8	593.8

The key reasons for the increased transmission Capex requirement are set out below.

Growth in peak demand

In order to meet underlying growth in peak electricity demand and customer connections, a number of key transmission line projects associated with capacity expansion have been planned. These projects are required to comply with Western Power's planning criteria and also the Technical Rules. Approximately $957M (44% of the total over the three year period) is attributable to six major line projects. These projects are as follows:

[1] Unless otherwise stated all dollars presented in this report relate to 30 June 2009 dollars

- the new Pinjar-Geraldton 330kV line, which is needed to provide infrastructure for connection of windfarms, coal fired base load generation and large industrial and mining loads ($361M)
- the new Kojonup-Albany 132kV line, which is required to provide suitable transfer capacity for the forecast peak demand ($139M)
- the Grange Resources Mine 220kV supply, which is required to accommodate a new bulk point load ($179M)
- the Shotts-East Terminal 330kV line, required in order to maintain voltage stability due to increasing load in the metropolitan area supplied by new generation connecting to the south-west network ($158M)
- the new Gindalbe Metals-Eneabba-Three Springs 330kV line ($74M)
- the new Wanneroo-Hocking-Wangara 132kV line ($46M).

New substations

An increase in the development of new substations is proposed; with 20 providing capacity expansion for growth and a further 2 anticipated for the connection of new point loads. As part of this program of work, Western Power will establish a new inner CBD substation to support the Perth city load area.

Asset replacement

A moderate increase in asset replacement expenditure is required to address an increasing backlog of aging plant that is of poor condition and performance and incurs high maintenance costs.

Compliance with standards

An increase in transmission pole replacements and upgrades to substation security is required to meet regulatory compliance, safety and environmental standards.

Cost Uplift

Additionally, significant real increases in both labour and material costs compared with current regulatory period costs are expected over the next regulatory period and have been factored into the forward estimates. These real cost increases have a significant impact on the magnitude of the forecast Capex.

As detailed in Table E2, increases are also expected in transmission network operational expenditures (Opex) over the next regulatory period.

Table E2 – Transmission operating expenditures, actual and forecast ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Network	56.7	55.0	50.2	73.5	77.9	84.1
Business support costs	18.5	20.6	24.3	27.4	28.0	28.7
Total Opex	75.2	75.6	74.5	100.9	105.9	112.8

The key reasons for these increased operational expenditures are set out below.

Increased asset population

The forecast transmission capital works program will result in a considerable increase in the quantity of assets requiring inspection and operation during the three year regulatory period. The forecast operational expenditures include allowances to manage these additional assets.

Cost uplift

Significant real increases in both labour and material costs are expected over the next regulatory period and have been factored into the forward estimates. These real cost increases have a significant impact on the magnitude of the forecast Opex expenditures.

Substation primary and secondary plant maintenance

Due to a combination of budgetary and resource constraints, only 60% of the preventative routine maintenance activity detailed in the relevant maintenance policies is currently being carried out. This level of maintenance is sub-optimal and will result in degrading service levels if continued. The transmission Opex forecasts for the next regulatory period provide for full compliance with the maintenance recommended in the relevant policies. As a result, forecast expenditure is expected to be approximately double that expected in the 2008/09 financial year. This is due to a combination of both increasing work volumes to prudent levels and cost uplift.

Substation HV equipment testing

Due to resource restraints and an inability to gain access to the equipment due to system loading constraints, current expenditure reflects approximately 50% of the number of tests required by the relevant asset maintenance policy. This level of testing is sub-optimal and will result in degrading equipment if continued. Forecast substation HV equipment testing expenditures for the next regulatory period provides for full compliance with testing specified in the relevant asset management policy.

Warranty inspection and testing

Expenditure for this preventative maintenance category is forecast to reduce over the next regulatory period as Western Power intends to focus its efforts on pre-commissioning testing which is proven to be more effective and reduces the need for system outages. This focus will result in a substantial reduction in equipment testing prior to the end of the warranty period. It will also increase resources for other transmission works. However, there will be a corresponding increase in commissioning costs associated with the proposed capital projects.

Silicon application to insulators

Sylgard protection applied to transmission insulators reduces pole top fires and also reduces television interference. This has been a very effective strategy that has been implemented for a number of years. The increase in forecast expenditure is approximately twice that anticipated for 2008/09 financial year due to uplift in unit costs. The volume of insulators treated is forecast to remain constant over the next regulatory period.

Overhead lines maintenance

Overhead line maintenance relates to the correction of conditions identified from inspections, and includes maintenance carried out from ground level, via helicopter platform or using live line techniques. Overhead line inspections include both inspection and rectification of the conditions found. Recent condition assessments have identified defect rates that are significantly higher than previously estimated. Expenditure for the preventive maintenance category is therefore forecast to increase over the forthcoming access agreement period. Expenditure for this preventative maintenance category is forecast to rise by approximately $1.7M or 53% between the final year of this regulatory period (2008/09) and 2009/10.

Distribution network

Western Power proposes to invest $2.29B (real) during the three year regulatory period on its distribution asset base.

Table E3 – Distribution capital expenditures, actual and forecast ($M)

Category	06/07	07/08	08/09	09/10	10/11	11/12
Network:						
- Growth related	300.1	279.3	315.4	324.9	342.3	358.4
- Non-growth related	118.8	157.7	222.0	299.7	337.6	410.8
Estimating risk factor	0	0	0	22.0	23.8	26.9
Business support costs	29.1	44.3	38.1	62.2	54.9	26.9
Total Capex	448	481.3	575.5	708.8	758.6	823.0

Table E3 shows that distribution network capital expenditures are forecast to increase from an average of $502M per annum in the 2006/07 to 2008/09 period to an average of $763M per annum over the next regulatory period. This represents an increase of 52%, of which approximately 46% is driven by growth related work. The balance is related to enhanced asset replacement practices, network reliability improvements, changing standards, and compliance with changing safety, statutory and environmental requirements. This additional expenditure is collectively categorised as 'non-growth related' in Table E3.

The key drivers of increased distribution capital expenditures are set out below.

Replacement of network

In a number of asset classes, the age of individual assets significantly exceeds the expected asset life, and these assets are now overdue for replacement. Specific strategies target those asset classes where action is required to arrest further degradation of asset class population and to ensure operational costs are managed while maintaining safety standards and moving towards mandated reliability targets.

Distribution feeder load reduction strategy

Currently, over 26% of metropolitan urban HV distribution feeders have utilisation that exceeds the planning criteria. Western Power has been unable to reinforce these feeders because resources have been allocated to the higher priority customer works. Consequently, specific strategies have been developed for the next regulatory period to target distribution feeder over-utilisation through increasing feeder capacity and enabling load transfers that will result in utilisation progressively moving towards compliance with the established planning standards.

Reliability performance

Western Power's network does not currently meet the required reliability standards. For the regulatory period commencing 1 July 2009, Western Power proposes to set a target reliability improvement of 29 minutes (SAIDI) to be achieved by 30 June 2012.

Meeting regulatory obligations

Changes to compliance requirements, in particular the *Guidelines for the Design, Construction and Maintenance of Overhead Lines* (HB C(b)1), drive much of the distribution Capex under the regulatory compliance category. Occupational Health and Safety matters and compliance with the requirements of the environmental protection regulations, as well as responsible and prudent management of public safety issues are also key drivers for this category of Capex.

Distribution Opex is also forecast to increase. As shown in Table E4, significant changes are expected in distribution network Opex over the next regulatory period.

Table E4 – Distribution operational expenditures, actual and forecast ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Network	207.0	204.2	197.1	317.4	337.8	355.6
Business support costs	46.9	55.3	65.8	76.6	78.7	80.8
Total Opex	253.9	259.5	262.9	394.0	416.5	436.4

The key reasons for this increased expenditure requirement are set out below.

Increased asset quantities

The forecast distribution capital works program will result in a considerable increase in the quantity of assets requiring inspection and operation during the three year regulatory period. The proposed levels of Opex include allowances to manage these additional assets.

Cost uplift

Significant real increases in both labour costs and material costs are expected over the next regulatory period and have been factored into the forward estimates. These real cost increases have a significant impact on the magnitude of the forecast Opex.

Pole maintenance

A new inspection regime has been implemented which combines pole ground line inspections with pole top and line inspections. This is expected to result in an increase in the quantity of remedial conditions identified. In addition, the average cost to rectify a condition has increased due to rising contractor costs.

Power pole bundled inspections

Western Power has recently combined the ‘ground-line’ inspection and treatment of poles with ‘above-ground’ pole inspection and line inspections and the inspection of customers’ services. This has resulted in efficiency savings but has necessitated the use of trained linespersons to carry out the inspections. The overall volume of inspections will remain the same (4 yearly cycle). In order to reduce the current rate of pole failures to the industry average, it is proposed to enhance the pole ground-line inspection process to include full excavation of the soil around the base of the pole in line with current Australian practice. Western Power is also investigating the use of ultrasonic pole strength testing.

Ground-mounted switchgear (and substation) inspection and maintenance

Budgetary restraints in the current period have resulted in only minimal expenditure on the inspection and maintenance of ground-mounted substations and switchgear. Western Power proposes to commence an inspection and maintenance regime of these assets in accordance with current asset mission statements. It has been estimated that Opex will increase as the additional inspections and resulting maintenance and repair works are implemented.

Emergency response generators

Western Power has a requirement under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, where practicable, to supply generators for customer supplies if planned outages are expected to exceed 6 hours or 4 hours on days where the temperatures are expected to exceed 30 degrees. Additional expenditures have been included for generator deployment in the next regulatory period because Western Power intends to decrease the number of customers affected by planned outages, and a corresponding reduction in the SWIS SAIDI minutes, by deploying emergency response generators to an additional four hundred planned maintenance events per annum.

Vegetation management

An unacceptable number of fires occurring in moderate fire risk zones have resulted in cutting cycles being reduced to two years. This previously occurred on a 3 year inspection and cut cycle.

Bulk globe replacement

Several changes to the bulk globe replacement program will result in increases to forecast expenditures. A four-year bulk globe replacement program has commenced during the current regulatory period. A further study indicates that the increase in costs to reduce the bulk globe replacement cycle from four years to three would be more than offset by the increase in customer safety resulting from the reduced luminaire outages.

In addition increased lumen output will be achieved as lamps would be replaced prior to their lumen output falling below 70% of the initial value and the luminaire lens would be cleaned more frequently. Western Power is phasing out the use of mercury vapour lamps and moving to the high pressure sodium lamps and is also trialling the use of highly efficient compact fluorescent lamps. Due to the age of the current fittings, both of these strategies involve the replacement of the entire luminaire and the control gear as required for the different lamps.

1 Introduction and background

Western Power is required to develop an access arrangement which describes the terms and conditions under which users can obtain access to Western Power's South West Interconnected System **(SWIS)**. The access arrangement defines network revenue projections and access tariffs, service standards and required capital and operating investment to meet these standards over the regulatory period.

The Economic Regulation Authority **(ERA)** is the regulator responsible for ensuring that Western Power's Access Arrangement is compliant with its obligations. Consistent with these obligations, the purpose of this document is to set out the capital and operating expenditure program that is forecast for the regulatory period from July 2009 to June 2012.

1.1 Structure and coverage of this document

The expenditures discussed in this document cover all transmission and distribution assets comprising the SWIS. Separate expenditure forecasts are provided for the transmission network and the distribution network.

The expenditures for non-network assets such as land assets, not related to the SWIS, are also included. These are presented and discussed as business support costs.

Section 1 provides information about Western Power's transmission and distribution networks, its key functions, organisation, customers and stakeholders and regulatory obligations.

Section 2 sets out Western Power's approach to asset management and network development.

Section 3 provides an overview of the key drivers for expenditure. These are further discussed under the relevant activity category in Sections 4 to 8 where appropriate.

Sections 4 set out the expenditures for business support costs.

Sections 5 and 6 set out the expenditures for transmission Capex and transmission Opex respectively.

Section 7 and 8 set out the expenditures for distribution Capex and distribution Opex proposals.

1.2 Approach to forecasting expenditures

Western Power has adopted a 'bottom-up' approach to forecasting its expenditures. For each type of activity, an activity template has been created. The templates set out the historical and forecast activity levels together with the drivers for the activity, the costing approach and assumptions made in forecasting costs, and other supporting information.

In this document, activities are grouped into categories and a high level summary of the activities within each category is provided.

All expenditure is shown in 30 June 2009 dollars. Where required, expenditures have been referenced to the 2008/09 year by using the June 2008 quarter of the ABS, Consumer Price Index, Weighted Average Eight Capital Cities (CPI) and anticipated cost escalation rate forecast from a study produced for Western Power by Access Economics.

Western Power notes that material costs and labour costs are forecast to increase at a rate which is greater than CPI. Hence, cost and asset escalation have been added to the expenditures forecast for the next regulatory period, as discussed in Section 3.9.

For some projects that form the basis of the expenditures forecast for the next regulatory period, formal commitments have already been made in the current regulatory period. In all cases these are transmission projects. As discussed in Section 5, this work-in-progress is a direct result of the 2006/07 to 2008/09 regulatory determination and so for these projects a brief summary only is presented in this report. Further information about these projects can be found in relevant regulatory test documents (where applicable). The majority of work in progress expenditure is subject to the investment adjustment mechanism[2] **(IAM)**.

1.3 Overview of transmission and distribution network

The transmission network transports electricity from generators via transmission terminal stations to zone substations and includes:

- transmission lines (overhead line and cable) and easements
- transmission terminal and zone substations (and associated plant)
- SCADA/communications infrastructure and land assets.

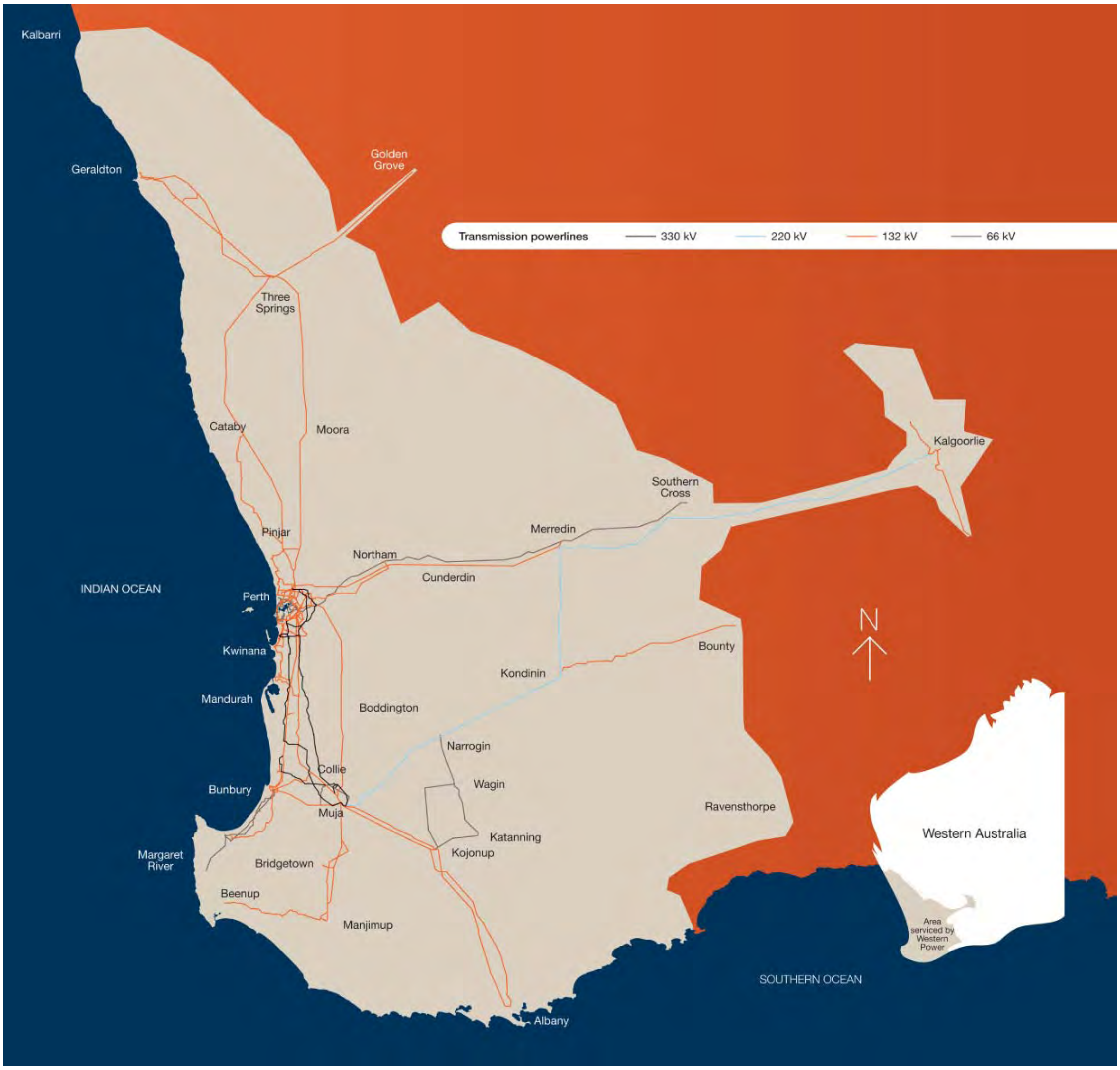
At zone substations, the voltage is transformed to distribution levels and the distribution network transports electricity through to customers connected at both high voltage and low voltage. The distribution network includes:

- distribution feeders (and associated plant) and consumer connections
- metering assets
- street lights.

The transmission and distribution networks cover a very large geographical area extending from Geraldton in the North, to Albany in the South and to Kalgoorlie in the east (shown in grey in Figure 1-1).

[2] The IAM is an *ex post* adjustment of revenue to account for actual additional capital expenditure encountered for growth related activities.

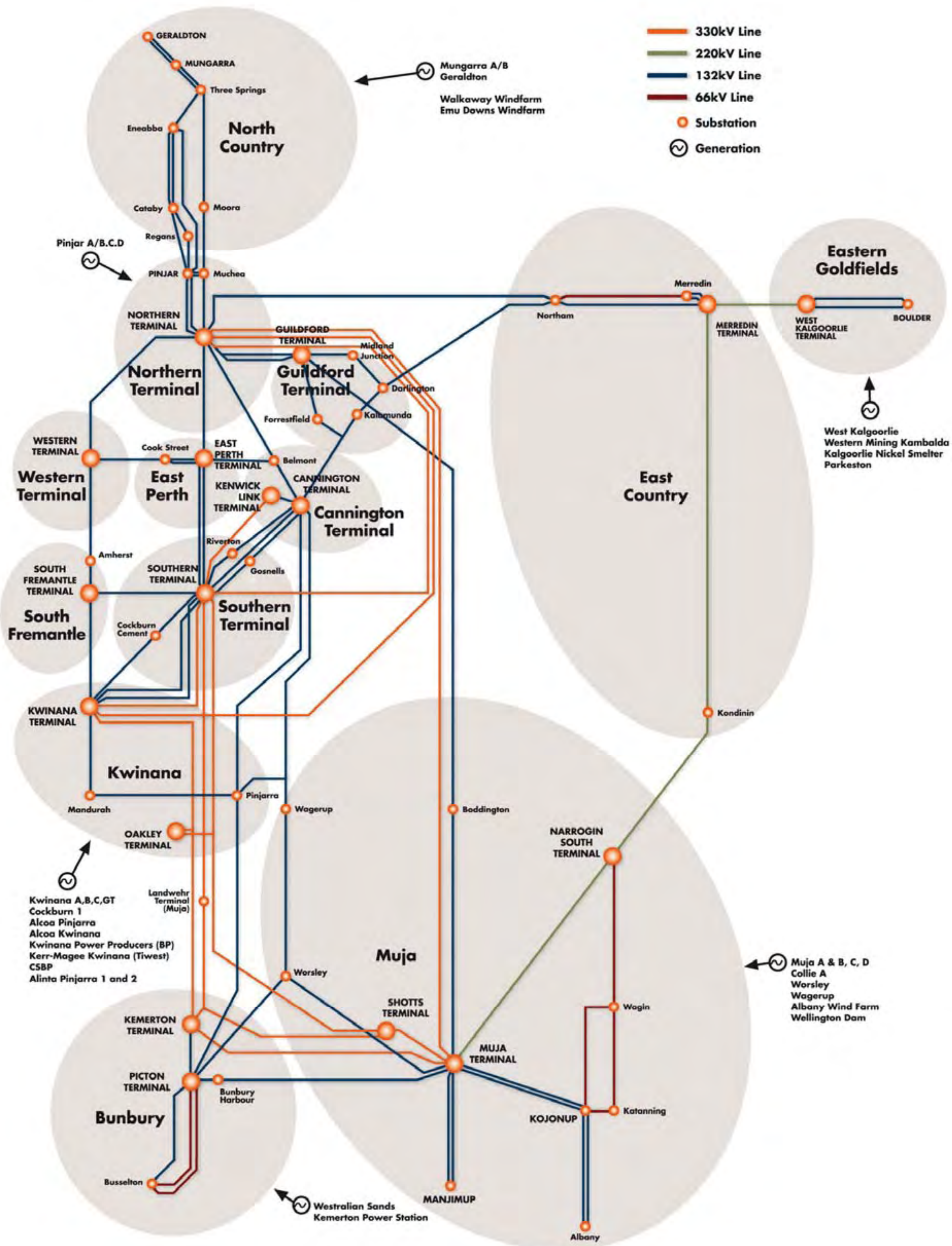
Figure 1-1 – Map showing area covered by the SWIS network



The SWIS is grouped into 13 load areas that constitute the bulk load area that addresses major system power transfer assets which are arranged primarily along geographic lines (refer to Figure 1-2). A relatively small number of bulk transmission terminal stations transfer power from generators over the 330kV, 220kV and 132kV transmission network.

Electrical energy is then transferred to a host of zone substations via the sub-transmission networks operating at 132V and 66kV. Zone substations further transform electricity to lower voltages (33kV, 22kV, 11kV and 6.6kV) for distribution networks covering the CBD, urban, semi-rural and rural areas.

Figure 1-2 – View of the 13 load areas within the SWIS



Key features of the SWIS are presented below in Table 1-1.

Table 1-1 – Key features of the South West Interconnected System

Item		Value
Peak Demand Summer / Winter (MW)		3,420 / 2,920
Energy Transmitted/Delivered (GWh pa)		14,500
Number of customers (power meters)		994,200
Customers per km of line (average number)		10.1
Transmission Lines Length (km)	330kV	795
	220kV	655
	132kV	4,290
	≤ 66kV	1,052
HV Distribution Feeder Length		68,900
LV Distribution Feeder Length		21,200
Demand (kW) per km of line (Distribution)		46
Bulk Transmission Substations		23
Zone Substations		170
Distribution Substations		11,400
Installed capacity of distribution transformers (MVA)		6,218
Number of Streetlights		213,100

Note: data is approximate as at 30 June 2008

1.4 Business responsibilities (description of services/functions provided)

Western Power is responsible for the regulated transmission and distribution network operations, network management and system management for activities in the SWIS.

Operating in a competitive electricity market, the Western Power business is independent of the competing generators and retailers and must provide access to network services for all market participants on an equitable and transparent basis.

Western Power's key business responsibilities are:

- managing the development and operation for the transmission and distribution networks comprising the SWIS
- operating on a sound commercial basis
- providing even-handed network access for all applicants
- delivering levels of network performance prescribed by all external regulatory bodies
- carrying out these functions safely and in accordance with safety and environmental legislation.

In meeting these responsibilities, Western Power must balance the requirements to operate commercially and meet regulatory, Government and community expectations for reliability of supply, with regular reporting to market regulators and operators.

1.5 Organisational arrangements and authorities

Western Power maintains a significant number of detailed policies and procedures relating to its capital investment program to ensure that its investment decisions are efficient and prudent. Key activities are performed to quality systems accredited to ISO 9001.

The Western Power governance framework for capital investment is depicted in Figure 1-3, together with some of the key documents.

Figure 1-3 – Capital investment governance framework and key documents[3]

Process	Key documents	
Network Vision and Objectives	Statement of Corporate Intent Stakeholder surveys Regulatory requirements and objectives Strategic Plan 2008 – 2010 Direction 2016	www.westernpower.com.au e.g. DMS 4525742 and 4479600 www.westernpower.com.au DMS 3845853
Network Investment Strategy	Strategic Asset Management Plan Asset strategy documents AA2 Technical Rules	DMS 2362422 DMS 3173588 DMS 5009513
Expenditure Forecasts	Annual Planning Reports Cost Estimating of Engineering Projects	e.g. DMS 4678963 DMS 4515944
Approved Works Program	The Works Program Manual Business Case Guidelines Capital Works Committee Terms of Reference	DMS 3565515 DMS 3198881 DMS 4229698
Expenditure	Monthly reporting Asset Investment & Risk Management – KPI Report Project Management Framework	 DMS 3358907
Review	Project Management Framework Analyse performance	DMS 3358907 DMS 4499406

Figure 1-3 shows that the governance framework covers all aspects of the capital investment program, including the development of long term strategies, identification and undertaking of specific projects and review. Specifically:

- Western Power has established a vision to transform itself into a sustainable energy solution business. This vision is set out in a publically available statement on the Western Power web-site www.westernpower.com.au. Objectives arising from the vision, and from information provided by stakeholders and regulatory obligations have been developed

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[3] DMS xxxxxxx is a unique reference number given to each document lodged in Western Power's Document Management System **(DMS)**.

- the overarching network investment strategy and the strategy for each asset category are set out in detailed documents
- expenditure forecasts are based on robust planning process and made in accordance with a documented process, taking account of current costs
- the works approval process is managed by a Capital Works Committee which scrutinises all proposed capital expenditures
- expenditures on approved projects and programs of work are subject to monthly review and a documented project management process
- project review is undertaken on all projects prior to project close.

Western Power's approach to asset management and network development are important aspects of the governance framework. These aspects are further discussed in Section 2 of this document.

1.6 Key stakeholders and influences

Western Power interacts with a large number of stakeholders, each having a specific, and often different, interest in Western Power's operations. Table 1-2 lists the key stakeholders and their major interests.

Table 1-2 – Stakeholder groups and major interests

Stakeholder	Major Interest
Public of Western Australia	Safety, environment, reliability, network access
Staff	Safety, income and reputation
Independent Market Operator **(IMO)**	Network access, forecast demand
Generators	Network access, forecast demand
Retailers	Reliability, network access, financial security
Office of Energy Safety	Safety, Technical standards
Suppliers	Security of revenue
Customers/ Industry Bodies	Safety, network access, comparative cost, rate of returı reliability
Economic Regulation Authority	Comparative cost, rate of return and reliability
Office of Energy **(OoE)**	Energy costs, reliability, energy policy
Government / Energy Minister	Dividend, safety, reliability, reputation
Insurers/Financiers	Exposure to material damage, financial security

Annual targets reflect Western Power's commitment to continuous improvement whilst meeting the responsibility to balance reliability with costs against customer/stakeholder needs and expectations.

To determine consumer perceptions and expectations with regard to the level of service provided, Western Power undertakes a number of activities involving customer consultation. Activities include:

- conducting market research
- recording, classification and trend identification of complaints

- engaging with customers
- undertaking specific consultation on major network projects
- obtaining direct customer feedback.

Information gathered through these various activities is taken into consideration during annual strategic planning and service level setting processes together with other inputs such as regulatory requirements.

Conducting market research

Western Power actively monitors reporting of its activities and performance in the media. This gives insight into customer expectations and perceptions of Western Power's performance in relation to service standards, network reliability, communications and customer satisfaction.

Recording, classification and trend identification of complaints

Western Power has a formal regime of managing complaints from customers which includes complaint recording, classification into root causes and subsequent trending over time. This analysis is then reported on a monthly basis to the Customer Services Management Team as part of overall network and customer performance measurement. Reliability and quality of supply related complaints have tended to dominate in recent times.

Engaging with customers

Western Power relies in part on the former Western Power Retail Business unit (Synergy) for residential and commercial customer feedback. Anecdotally, most issues raised are related to pricing, customer service standards and network related projects rather than network performance issues such as reliability or power quality.

Undertaking specific consultation on major network projects

Western Power's Environmental and Land Management Section undertakes and coordinates consultation with affected stakeholder groups for major network projects such as new substations and line routes.

This process includes:

- constraint analysis – investigation of visual, environmental and noise etc. related issues
- development of stakeholder management plans
- contacting relevant authorities such as Local Government Authorities, Conservation and Land Management and the Environmental Protection Authority
- liaison with landowners and affected communities as appropriate
- ongoing negotiations and management of resulting issues.

This process ensures that key stakeholders have knowledge and input into the benefits and costs of major projects. Consultation has revealed that stakeholder groups generally accept the need for major projects in maintaining and improving reliability of supply, whilst preferring them to be located 'elsewhere'.

Direct customer feedback

Account Managers for larger network customers ensure that direct customer feedback is obtained on Western Power's performance and service standards.

1.7 Regulatory requirements

Western Power undertakes its planning and network development activities in line with a number of legislative requirements. Key obligations are contained in the *Electricity Networks Access Code 2004* (the Access Code), *Electricity Industry (Network Quality and Reliability of Supply) Code 2005,* the *Technical Rules* and the *Electricity (Supply Standards and System Safety) Regulations 2001* (the Regulations). Together these documents define technical, customer access, and public/network safety requirements.

Western Power is regulated by the ERA in accordance with the Access Code. Under the Access Code, Western Power must develop and adhere to an Access Arrangement that defines the terms and conditions under which users may access the network. The Access Arrangement also defines the network revenue projections and tariffs, the service standards to be met by Western Power and the capital and operating investment expenditures required to meet these standards over the regulatory period. The ERA ensures that the Access Arrangement complies with Access Code requirements and approves levels of expenditure and the resulting prices for the regulatory period. Western Power's expenditure program has been developed to meet its Access Code obligations.

Western Power also works within the framework set by the Regulations and Technical Rules to ensure the following outcomes:

- safety standards are maintained
- adequate network capacity for network load and power transfer
- each individual piece of network equipment is operated within its design limits
- the network can withstand credible faults and unplanned outages
- quality of supply meets the appropriate standards
- future growth is adequately catered for
- environmental constraints are responsibly managed
- network access requirements are met
- required/declared service levels are achieved.

The expenditure forecasts in this document are consistent with Western Power's regulatory obligations.

2 Western Power's approach to asset management and network development

Asset management is the most important function undertaken by Western Power. Asset replacement and new additions to the network are the key drivers of network prices.

In this section, we set out Western Power's approach to asset management and the key planning strategies, systems and process, investment tests and risk management strategies.

2.1 Overview of asset management strategy

Since commencing operation as a transmission and distribution network-only business on 1 April 2006, Western Power has undertaken a period of rapid change. The introduction of the IMO and the implementation of the Access Code and economic regulation have required Western Power to change the way it operates.

Western Power has updated its Strategic Asset Management Plan **(SAMP)** to ensure it is aligned with the new Access Code and the regulatory framework. As a result, some of the key network documentation that Western Power uses has been updated; however the task of updating and altering the related network documentation continues.

The optimisation of Capex, Opex and reliability outcomes is a challenging but critically important process for any electricity asset business. The transmission and distribution asset management strategy is expressed as a series of principles upon which asset management procedures and decisions are based to support the Networks' asset management policy.

Long term asset maintenance and renewal plans are prepared annually and are based, where practicable, on the following items:

- asset condition and age
- the asset's expected system role, taking into account the potential obsolescence
- the probability and consequence of failures
- the physical and system environment within which the asset is required to operate
- realistic asset decay predictions and subsequent life-cycle cost planning
- the need to ensure the long-term viability of the business, that is, to avoid reaching a situation where the overall condition of the network has declined to an unmanageable state.

Investment in the existing asset infrastructure is based on the need to:

- ensure safe operation of assets
- maintain required service levels
- reduce servicing and operating costs
- optimise the economic life of equipment
- meet regulatory and environmental requirements.

All proposals for major expenditure are prepared using Western Power's economic assessment and project approval processes. This includes a detailed operating and capital funding requirements review and prioritisation process which is fed into the overall Western Power budgeting framework.

Maintenance is completed for each type of equipment in order to:

- achieve minimum maintenance and capital costs
- ensure the asset condition is within acceptable limits
- operate the equipment at an acceptable level of risk
- meet required performance targets.

Maintenance plans take into account overall life-cycle plan for the assets, including renewal and disposal plans and future development plans.

Risk exposure is identified through:

- due diligence programs
- asset audits
- analysis of performance history
- other specialised risk analysis projects.

Critical assets are managed within a standard risk management framework. Special contingency plans are developed for significant risk scenarios.

All asset management work is carried out in accordance with relevant legislation and national standards and industry guidelines (including occupational health and safety, environment and employment).

Information systems have been developed to enable:

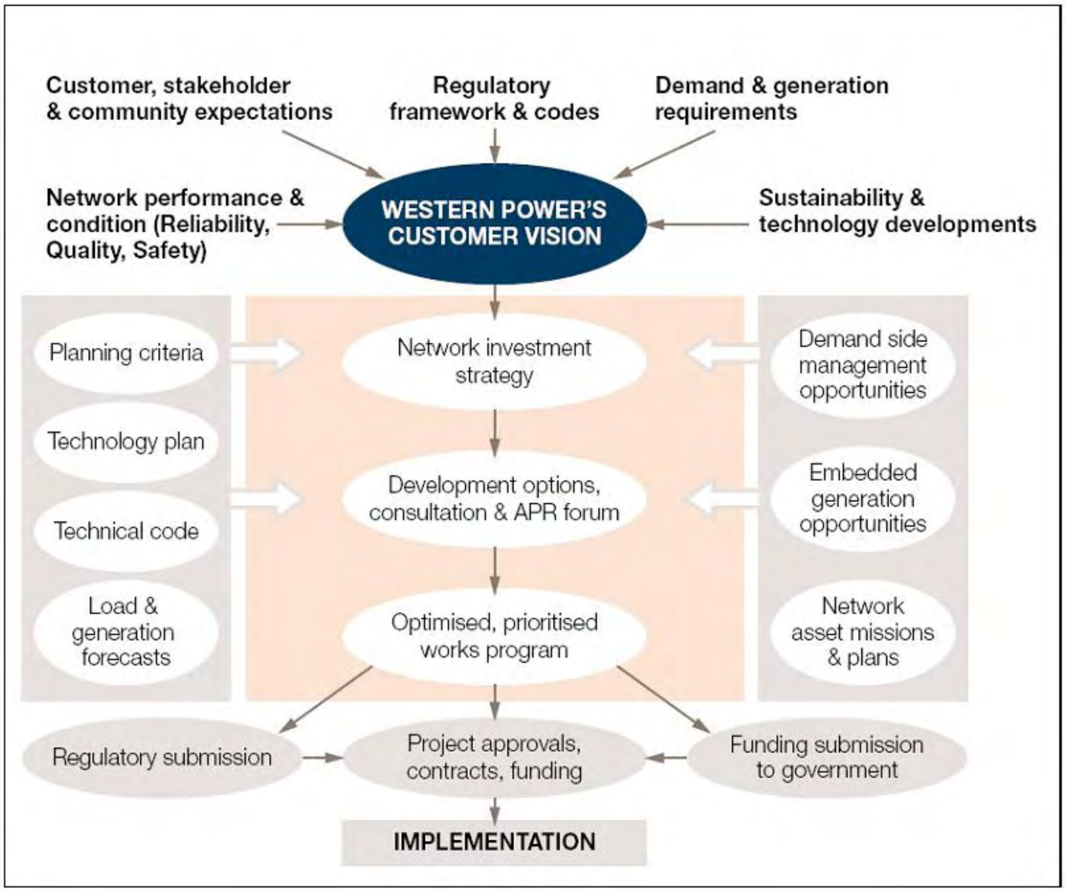
- registration of Western Power's existing assets and their characteristics
- recording and management of asset management procedures and activities
- provision and review of asset performance statistics.

2.2 Overview of network development planning criteria and process

This section provides an overview of the network development planning process, Western Power's understanding of customer expectations, the planning criteria used in developing the network and other technical requirements.

As a prudent commercial organisation, Western Power applies risk management principles when determining its network development. Applying agreed network investment criteria, Western Power's planning process is focussed on balancing network costs against the impact of unreliable supply on its customers. Those planning principles are applied within the planning and development framework, illustrated in Figure 2-1.

Figure 2-1 – Overview of planning process



Western Power's network investment strategy is developed through a number of contributing factors. These include:

- *Technical rules*: Western Power has established technical rules for transmission and distribution performance standards for the network and technical requirements for plant connected to the network
- *Load and generation forecasts*: Western Power's forecasts are based on projections of state economic growth, load history and customer connection enquiries. Western Power also makes prudent assumptions about the development of generation projects
- *Asset management plans*: The asset management plans are based on condition assessment of the network to ensure that it will continue to provide reliable service. Condition assessments drive the asset replacement component of the Network Investment Strategy
- *Western Power's commercial objectives:* Western Power's strategy is developed in light of the various drivers illustrated in Figure 2-1, and includes the normal commercial objectives of any business, as required for Western Power under the Electricity Corporation Act 1994. In addition, the regulatory environment means Western Power's capital expenditures need to satisfy the stringent requirements of the Access Code. It must also demonstrate that investments are economically justifiable under the New Facilities Investment Test, and that possible alternative options to major investments have been evaluated and considered as part of the Regulatory Test.

These inputs are used in advanced and systematic network analysis that ensures all the equipment and elements of the network satisfy the defined planning and technical criteria, so that:

- each individual network element is operated safely 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[4]
- the network can withstand credible faults and unplanned outages. A fault is considered credible if it is considered likely 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 does not impede economic development
- environmental impacts are responsibly managed.

For convenience, the network is considered to be divided into load areas. Each load area is studied in detail to ensure that it continues to meet the relevant planning and technical criteria.

2.2.1 Network development analysis

The planning and operation of electricity networks must meet certain technical requirements. There are various factors that will change power flows across the network, which must be taken into account when planning and operating the system. These include the following:

- changes in network configuration, either by construction of new elements or outages of existing network elements
- location and timing of new generation sources has an impact on thermal (asset) capacity, stability and fault performance, and thus the need for network augmentation
- location and timing of major new loads or load centres
- rate of forecast network load growth and long-term growth trends also determine the need for network augmentations.

Specifically, the network development analysis process undertaken by Western Power is highly sensitive to changes in any of these factors. Therefore, network development analysis can only indicate likely network constraints. Similarly, the options for addressing these constraints are based on specific assumptions and judgements regarding future events. Variations from these specific assumptions may change the development scenario profoundly. Such changes are addressed through the IAM (for complying capital projects).

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4 Failure to meet voltage design limits can result in malfunction or damage to customer equipment, while exceeding power transfer limits creates potential safety hazards and reliability issues arising from the failure of network equipment due to overloads.

2.2.2 Transmission network planning standards

Western Power develops its transmission network in accordance with the Technical Rules.

Generally, the transmission system is a meshed network[5] with a high proportion of elements in service at any given time. The transmission system is broadly divided into the bulk transmission network, the sub-transmission network, radial networks and substations.

The planning criteria for the transmission network are based on a risk analysis that takes into account:

- the size, extent and sensitivity of load or generation which may be affected
- the physical location of various components of the network and their exposure to damage risk
- the relative merits of other alternatives
- the efficient use of capital.

Bulk transmission network

The bulk transmission network operates at 330kV, 220kV and 132kV. It consists of the power station switchyards, major terminal switchyards and the interconnecting transmission lines.

In accordance with the Technical Rules and Western Power's planning criteria, the bulk transmission network is designed to withstand a single unplanned outage without loss of load. It is also designed to withstand one forced outage and one planned outage at 80% of forecast peak load (assuming generation rescheduling after the first outage).

The bulk transmission network requires this level of security given the high capacity of the bulk transmission network where outages may affect many customers.

Sub transmission network

The sub-transmission network operates at 132kV and 66kV. It consists of zone substations and the interconnecting lines.

The sub-transmission network is generally designed to withstand a single unplanned outage without loss of load. When there is more than one outage at the same time, there may not be sufficient network capacity to meet all demand. Sometimes, there may be limited back-up capacity available via the distribution network.

This broadly applies to the network supplying urban areas in the Perth metropolitan region and major regional centres. These parts of the network tend to be characterised by relatively high load density and shorter lines.

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5 Meshed networks: circuits with multiple connection points to other circuits.

The Perth Central Business District **(CBD)** sub transmission network has a higher level of security requiring continuous supply following two coincident outages and the ability to restore supplies in a reasonable time should a substation be lost.

Radial networks

Radial networks operate at 220kV, 132kV and 66kV and generally supply loads of less than 20MW. The 132kV and 66kV radial networks generally supply regional townships in Western Australia's South-West region.

Radial networks take into account analysis of network reliability, risk and economics. In a radial network, backup may be provided by other parts of the transmission network, the distribution network, local generation, or not at all, depending on analysis.

It is not always economic to provide full redundancy on the radial networks due to the large line-lengths, geographically dispersed loads and generally smaller loads (when compared to urban areas).

Substations

Substations interconnect the sub-transmission network with the distribution network. Each substation is designed to meet planning criteria that depend on the substation's location and the type of load it supplies:

- substations in the Perth CBD are designed to provide the highest level of security due to the relative importance of the load supplied by these substations
- regional substations are designed to provide the next highest level of security recognising the long travelling times required before plant can be repaired or replaced, although there are some remote substations designed to provide a relatively low level of security
- substations in the Perth metropolitan area are designed to accept a higher level of risk of load shedding (loss of load) than in the CBD or regional areas, as they are more readily accessible for plant repairs or replacement. The designs of the various types of substation recognise the need to optimise security of supply and capital expenditure.

CBD substations are designed to withstand the failure of a single item of plant without any sustained loss of customer load. They are also designed to withstand the failure of either two items of plant or both lines that supply the substation with only a temporary interruption to customer load and the ability to restore supplies in four hours.

Most regional substations are designed to withstand the failure of a single item of plant without sustained loss of any customer load. A small number of regional substations are designed to withstand the failure of a single item of plant with a small risk that up to 10% of the load may need to be shed. This risk only applies for one percent of the time throughout a year and is based on the availability of suitable spare equipment.

A small number of regional substations are not able to continue to supply customer load for a failure of a single item of plant. These substations have usually been established for the purpose of supplying a single customer and where the customer has accepted the risk of loss of supply. If nearby loads then take the opportunity to be supplied by these substations, it is often not economic to provide higher supply security.

Most substations supplying the Perth metropolitan area are designed to withstand the failure of a single item of plant (about a one in twenty-year event), accepting that some customer load may be shed, on a rotational basis, for up to nine hours. In line with commercial objectives, since 1996 Western Power has accepted the risk of short-duration load-shedding to maximise the utilisation of substation capacity.

2.2.3 Distribution network planning

Western Power develops its distribution network in accordance with the Technical Rules, published in April 2007.

The distribution network operates at 33kV, 22kV, 11kV, 6.6kV and 415V. It is broadly separated into the CBD, urban and rural networks. Each of these categories is discussed further below.

Western Power's distribution system is generally designed to operate radially[6]. Normally, the loss of a network element will result in loss of supply to a number of customers.

There are a number of factors that mitigate the length of interruption for customers. Connections between feeders provide back-up for when the normal supply to a portion of a feeder is unavailable. Reclosers[7] and sectionalisers[8] are used to facilitate resupply to sections of feeders. Western Power also uses fault indicators, load-break switches and remote-control pole-top switches to improve the speed of fault location and isolation. This facilitates rapid restoration of supply.

CBD

The CBD distribution network is an open-meshed[9] and remotely-switched design. This facilitates rapid restoration of supply to healthy sections of the network after faults. In addition, CBD zone substations automatically reconfigure feeders after the loss of step-down transformers. The total loss of a single-zone substation requires manual network reconfiguration to restore supplies within four hours. CBD feeders are normally limited to 50% of their maximum rated capacity. This provides flexibility to remotely reconfigure the network and to restore load after a feeder outage.

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6 Distribution feeders are designed such that real power flows in one direction from the source (substation LV bus) to the load along a single path.

7 To ensure equipment is not needlessly out of service for transient faults, some equipment will automatically re-energise the network element after a short delay. This is known as 'automatic reclosing'.

8 Sectionalisers automatically disconnect faulted sections of feeders and hence allow the location of the fault to be identified more easily and service to be restored to customers up-stream from the faulted section.

9 CBD open meshed: A feeder interconnected to another feeder, supplied from another CBD zone substation, through a normally open switch at the point of interconnection.

Urban

Urban distribution networks in metropolitan areas and regional towns are open-meshed networks[10] with radial feeders and inter-feeder ties that can be switched into service as required. This moderate level of interconnection between feeders and a planned maximum feeder loading of up to 80%[11] allows for the transfer of load between feeders after a fault. In contrast to the CBD, this transfer of customer load may require a number of manual-switching operations.

This feeder arrangement minimises fault levels and simplifies technical and operational requirements. With multiple open points, improved supply restoration times are possible, although the initial loss of supply will still occur.

Rural

The distribution networks in rural areas are radial and are much longer than urban feeders, with limited inter-feeder ties due to the dispersed nature of these networks. As a result, supply restoration after a network fault can take longer. Some distribution feeders can be very long, with no interconnection to facilitate supply restoration.

Users requiring a level of supply security above that achieved through the standard design philosophy may be provided with an alternative (backup) supply or other network solution where practicable. Customer-side solutions, however, such as on-site standby generation may be more economic. Investment to provide additional security of supply is normally undertaken at the customer’s expense.

2.2.4 Quality of supply requirements

Aside from the extensive planning criteria described above, Western Power applies technical requirements to ensure that the quality of electricity supplied to customers is acceptable. These requirements affect the design of the network and its elements. They include characteristics such as flicker[12], voltage limits, waveform distortion and waveform imbalance.

Broadly speaking, the requirements are found in various national and international codes of practice and standards. They are widely accepted by electricity utilities and by electrical equipment manufacturers.

Western Power also has quality of supply obligations established by legislation. The *Electricity (Supply Standards and System Safety) Regulations 2001* contain various quality-related benchmarks while the *Technical Rules* also set out technical requirements.

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10 Urban open meshed: Distribution feeders with multiple points of interconnection to other feeders through normally open switches at the point of interconnection.

11 In some instances a reduced number of alternative feeders are available and a 67% (or other) loading criterion is used for practical purposes.

12 Flicker is a variation in the magnitude of supply voltage caused by fluctuating loads on the network.

2.3 Systems, processes and procedures

Western Power has established IT and data management systems to assist in the collection and analysis of network information. The key systems are described below.

- *Document management system (DMS*): All business document records are stored in an electronic document management system. A unique DMS number is assigned to each record
- *SCADA:* Supervisory, control and data acquisition systems **(SCADA)** are used for the real time monitoring of key transmission and distribution equipment. The systems also provide remote control of key network equipment. The Electricity Network Management and Control **(ENMAC)** system at the East Perth Control Centre used to manage the distribution network is currently being enhanced to include functionality to manage outages and customer trouble calls. The XA/21 Energy Management System **(EMS)**, used to monitor and control generation and the transmission network and to provide data to support the electricity market, is also being developed. It includes an enterprise agreement for OSI PI Historian, and a long term maintenance upgrade program
- *Idelve:* This recently introduced system provides network operational data via intranet on a geographic overview to assist in decision making
- *Customer information system:* Until recently, Western Power relied on systems owned by the former Western Power retail business unit (Synergy) for its customer service and network billing functions. A new Customer Information System – NETcis – now provides customer information and retailer billing
- *DFIS:* A distribution feeder information system that contains the connectivity model of the distribution system
- *Active model:* The active model is used by the Trouble Call Management System for grouping calls to fault jobs and for generating phone messages for customers. It is a copy of the DFIS switchable sections that can be kept active by applying every switching action to it. It is linked to the SCADA system so any switching operations that occur in SCADA also occur in the active model
- *Trouble call management system (TCMS):* Western Power has commenced a process to implement a new Trouble Call Management System to allow Western Power to remove the dependency on the former Western Power retail business unit (Synergy), in particular the current mainframe based TCMS. A trial has been completed of the Electricity Network Management and Control (ENMAC) Trouble Call System **(TCS)**, including ENMAC TCS Mobile, to support the organisations management of outages; and the ENMAC Mobile Switching module, to improve safety, and the accuracy and efficiency of network switching operations. The new system is to be implemented within the current regulatory period
- *PSS Adept:* A planning tool used for network load flow calculations
- *Ellipse:* An asset management planning tool
- *MIMS Ellipse:* An enterprise resource planning system (Mincom Ellipse) that consolidates and improve asset management functionality in Ellipse (previously carried out in the DFMS, TPMS, TRIS and TLS systems)
- *Data Warehouse:* A data warehouse system with the information reporting and analysis based on Cognos Business Intelligence technology
- *Metering Business System (MBS):* manages meter asset and meter reading activities; provides standing data and reading data to the WA Electricity Market; dispatches

service orders to the Metering field workers; and acts as a work force management system for Metering Services

- *System Management's information technology system (SMITS):* provides the systems and processes required to fulfill Western Power's functions and obligations in the Wholesale Electricity Market. The ERA has previously approved funding for this project, and the recovery of its forecast expenditure has been authorised from Wholesale Electricity Market participants.

2.4 Access Code investment tests

Network investment is subject to two tests defined within the Access Code, namely the New Facilities Investment Test **(NFIT)**[13] and the Regulatory Test[14].

The NFIT is essentially a prudence and efficiency test to determine the appropriate value to roll into the capital base. The NFIT defines reasonable prudence and efficiency with respect to factors such as minimisation of costs, economies of scale and reasonable forecasting horizons for new facilities investments. The test provides a prescriptive definition of investment considerations that are considered pertinent for an electricity network business. An example is the use of standard sizes for transformers and conductors which results in a minimisation of total investment costs, or the application of agreed planning time horizons when determining appropriate levels of investment in network capacity.

The NFIT also defines the acceptable technical and economic criteria that must be satisfied to determine the appropriate new facilities investment. These broadly cover:

- the ability to recover the investment from the incremental revenue
- the investment provides a net benefit, or
- the investment is required to maintain reliability, safety or contracted services of the covered network.

Many of the forecast capital expenditures proposed in this submission have not yet been subject to the NFIT assessment, which is routinely carried out as part of the development of specific business cases. The planning processes applied by Western Power to determine the need for network investment, however, and the evaluation of options, are already well aligned with the intent of the NFIT with respect to business drivers, performance outcomes and the prudence and efficiency of the investments. The capital expenditure forecasts proposed in this submission are based on a 'bottom up' assessment of investment requirements based largely on these planning processes. As such, Western Power is confident that the investments proposed in this submission satisfy the NFIT.

The Regulatory Test is a test which must be applied prior to the commencement of major augmentations where the value of the project exceeds the nominated threshold ($5.4m for distribution projects and $16.2m for transmission projects[15], $2007/08). This test is in place to ensure sufficient consultation and evaluation has been performed prior to the

13 Access Code Clauses 6.52 – 6.55 inclusive.

14 Access Code Chapter 9.

15 The values of these thresholds are currently the subject of study by the Office of Energy and are expected to rise to $10M and $30M respectively.

augmentation being undertaken. The test defines key undertakings and considerations that must be performed. These broadly cover the consultation process, the use of market development scenarios, and the maximising of the net benefit of the augmentation.

2.5 Risk management approach

As the provider of critical infrastructure and essential services, Western Power recognises the importance of delivering high value services to its customers and therefore strives to manage its business risks effectively and efficiently. Safety — both public and network — is justifiably the primary consideration in all business and workplace activities.

Western Power has developed a project risk management framework that is consistent with the standard AS/NZS 4360:2004. It consists of a Capital Project Risk Management process and an Investment Optimisation Planning Tool.

The Capital Project Risk Management Process aids in the effective management of individual project risks, both threats and opportunities. The process provides a systematic framework for planning, identifying, analysing, responding to, and monitoring project risks. Three risk 'tiers' are used to classify project options:

- Tier 1 (Low Risk) is for projects with routine activities and can be considered to be extensions to current operations e.g. extension of existing networks, selection of least cost options for minor capital expenditure and maintenance.
- Tier 2 (Medium Risk) is for projects where the nature of the project represents a higher level of risk to the business e.g. provision of secured funding of customer assets, co-generation projects.
- Tier 3 (High Risk) is for projects with a significant departure from the core activities of the organisation. Characteristics include a high level of expenditure, long timeframes or uncertain success of the project e.g. new business venture other than electricity, acquisition/construction of long life generating plant.

A number of project aspects are assigned particular risk tiers in order to determine the overall project/option risk. Examples of characteristics include: technology, project scale, payback duration, regulatory environment and management experience.

The project team completes the risk management plan and the risk register. The team updates the register regularly in each subsequent lifecycle component and continues to monitor and control risks throughout the life of the project.

The Investment Optimisation Planning Tool seeks to identify and select treatments that offer the best risk mitigation value across the network risk portfolio. Using the efficient frontier analysis approach, the tool is used as an input into the efficient sequencing of the capital and operational works programs. The tool currently provides broad outcomes and is being further developed.

2.6 Works program delivery

The environment within which Western Power operates is significantly different to that of previous years. Whilst disaggregation of the state owned, vertically integrated electricity business - and the associated regulation of transmission and distribution services - are the primary contributors to this change, there have been numerous other business challenges impacting on how we deliver Western Power's services. Some of these are:

- Western Power's remote geographical location, the real time nature of electricity delivery and being a natural monopoly, has lead Western Power in the past to adopt a strategy to be as self reliant as possible in all operational aspects. This self-reliant approach was based on retaining control over works internally whilst engaging limited support of external parties. However, this existing approach is inadequate to deliver the magnitude of works forecast for the next regulatory period
- The commodity boom has increased demand for equipment supplied by suppliers, resulting in delivery constraints and some shortages
- A major skills shortage in the infrastructure development industry is becoming a significant constraint to implementing Western Power's works program
- The previous engagements of external parties to supplement the internal workforce have largely occurred on preferred vendor arrangements, with some design and construct contracts[16].

Recognising the limitations of its previous approach, Western Power has developed a long-term Strategic Delivery Framework[17] with respect to the delivery and resourcing of the forecast works program. The focus of this framework is to establish a balanced 'portfolio' of service delivery options to maximise Western Power's flexibility to change with changing needs and demands as well as reduce the long term cost of service delivery.

The core of the framework, as shown in Figure 2-2, consists of a work allocation system that was first developed in 2008. It assesses the delivery risk of each type of work type and allocates high risk work to internal resources and lower risk work to Western Power's contractors. An outcome of this approach is the allocation of a greater portion of work types to contractors than previously.

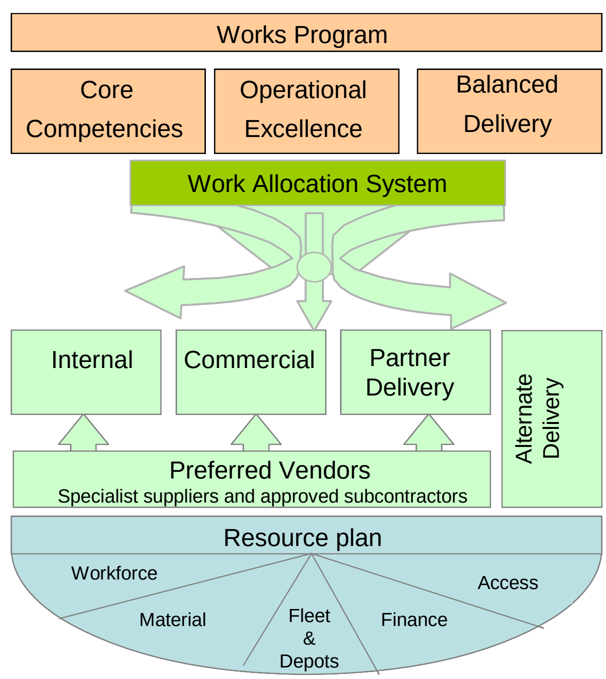
In developing the framework, Western Power undertook a detailed analysis to identify the most appropriate contractor arrangements and has moved to implement the following arrangements:

- alliance partners
- partner delivery agreements
- commercial contracts
- preferred vendors
- alternate delivery mechanisms.

16 Historically the approach to managing and engaging with the external market has been inconsistent, where transmission Capex projects have been outsourced for some years but only limited distribution Opex and Capex have been undertaken by external service providers. To some extent, these arrangements have increased overall capacity and provided flexibility in the delivery of the works program, however the short-term nature of these arrangements resulted in higher margins, and did not provide sufficient certainty to encourage contractors to bring additional capacity to the state

17 DMS 4753487: AA2 Delivery Plan 2009/10 – 2011/12

Figure 2-2 – Works program delivery framework



The framework represents the objectives and the components that support the delivery of the Works Program.

1. The Works Program is at the top of the framework as it forms the basis under which all of the components and systems are formed. An accurately defined and approved Works Program is critical for successful delivery.
2. Below the Works Program are the links to the corporate objectives as defined under Operational Excellence, i.e. Core Competencies, Operational Excellence and Balanced Delivery Portfolio.
3. The middle of the framework forms the systems and processes to enable the Works Programs to be matched to the most appropriate delivery mechanism.
4. The bottom of the framework symbolizes the resources, systems and processes required in delivering the works program

In addition to Western Power's own internal delivery capability, each of these delivery mechanisms is discussed in detail below. Of particular importance is the strategy for increasing resources under each delivery strategy, so as to provide an adequate work force to meet the increased works program proposed for the current and next regulatory periods.

Internal delivery

Western Power's internal operational workforce has core competencies in delivering most areas of the works program, including maintenance, overhead and underground distribution services, new substations and upgrades, and transmission line upgrades. A major strength of the internal workforce is in planning and design, which Western Power will supplement with external designers during peak workload periods.

Alliance partners

Western Power has recently put in place a multi partner alliance with Downer EDI and Tenix and a single partner alliance with Transfield Services. These alliance partners will be responsible for the end-to-end delivery of new and upgraded transmission substations, new transmission lines and customer funded distribution programs. Western Power has undertaken discussions with its alliance partners about increasing resourcing to meet the future works program. Both alliance partners have indicated an ability to increase resourcing through a combination of overseas recruitment, interstate transfers of current employees, and targeted recruitment from eastern states of Australia.

Distribution partner agreements

Western Power is developing a partnering arrangement with key contractors to begin in the 2008/09 period. The arrangement will allow the allocation of longer contract periods, giving certainty to contractors of future work loads and hence an ability to increase resource levels. The partners will deliver distribution overhead and underground services as well as maintenance works, including vegetation cutting in four regions across the SWIS.

Commercial contracts

Contracting of work using the AS 4000 series contracting standards has been a key component of Western Powers traditional delivery strategy. It will continue to be used for engaging industry in specific work assignments such as transmission customer funded work, minor transmission line projects and for specialised services such as silicon spraying and washing of insulators, vegetation management, inspections, streetlights and state undergrounding programs. Western Power has good relationships with many exiting companies in WA and is continually scanning the market for new entrants to WA to assist with its expanding program of works.

Preferred vendors

Western Power has established a panel through a competitive tendering process of pre-qualified contractors/suppliers and allocates work on an ad-hoc basis. The preferred vendor model is well established and will be used to supply specialist services such as aerial surveys, traffic management, route selection, environmental reports, cable ploughing and laying, and to provide support to the internal workforce and other prime delivery mechanisms. Being essentially non-industry specific, preferred vendors are able to adjust resources readily to suit the Western Power works program.

Alternate delivery

An alternate delivery option currently being considered is to allow customers to build parts of the network, which Western Power will ultimately own and operate. This is usually via Western Power's pre-qualified contractors; however Western Power does not fund or manage the work. Other models that are being examined include Task Force Branches within Western Power, Subsidiary Company options and Acquisitions. This will be the prime delivery mechanism for delivery of unregulated works.

2.7 National comparators

Western Power engaged independent consultants to compare its performance with similar businesses in Australia and to obtain verification that the estimated values used for transmission capital works is in line with national averages.

In this section, we present the outcomes of these studies.

2.7.1 Financial performance comparators – transmission

Parsons Brinckerhoff Australia Pty Ltd **(PB)** was engaged to provide information on a range of financial and network comparators. The electricity network businesses included in the comparison were Powerlink (Qld), TransGrid (NSW), EnergyAustralia (NSW), SP AusNet/VENCorp (Vic), Transend (Tas) and ElectraNet (SA). Information was sourced from the most recent regulatory decision for each business.

PB noted that when making comparisons between Western Power and other electricity network businesses, care must be taken to establish like for like comparisons. This is because Western Power's network consists of both transmission and distribution elements. Within Australia, electricity network businesses are typically a transmitter or a distributor. Further, transmitters typically only provide services between generators and major load centres (via transmission lines and terminal stations). In Western Power's network, transmission services extend to local load centres (via sub-transmission lines and zone substations). Elsewhere, this sub-transmission layer of the network is managed by distributors.

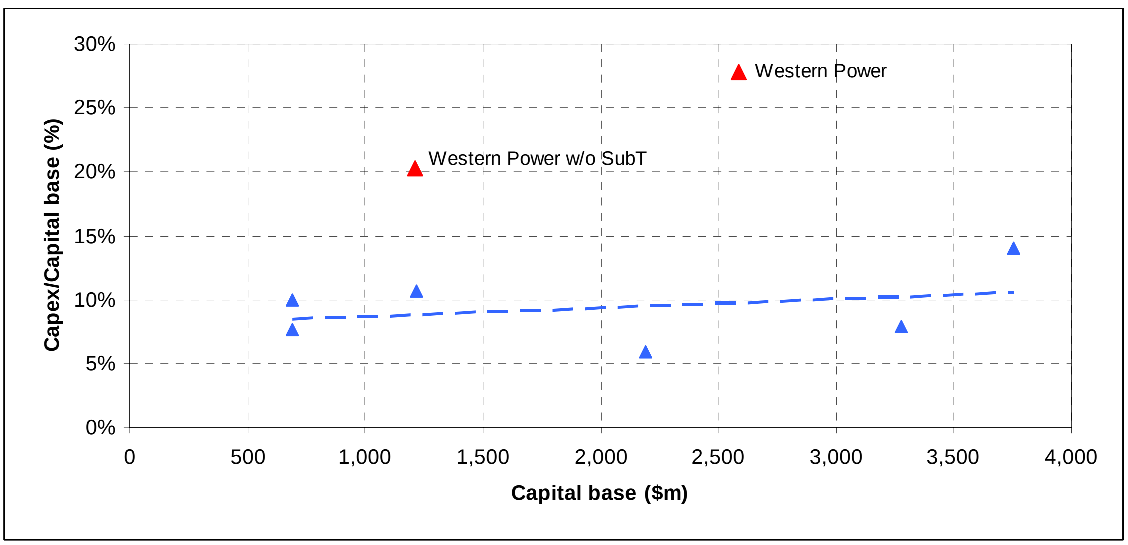
It is not possible to simply identify the costs associated with the subtransmission layer either in other businesses distribution networks (that are publically available) or in Western Power's transmission network (due to the current cost allocation method). Hence, in order to obtain a like for like comparison, an estimate of the costs associated with Western Power's subtransmission layer has been made and where appropriate the comparators are shown with and without the sub-transmission layer.

Figure 2-3 shows transmission Capex as a percentage of the capital base. The figure shows that Western Power's forecast Capex is considerably higher than for other transmission businesses. This is because of the relatively small network spread over a vast area that results in higher costs when providing additional network to meet its regulatory obligations and customers needs[18]. Western Power is unique in this respect.

Figure 2-4 shows that Western Power has the highest forecast growth in maximum demand in Australia and that the high Capex requirement is largely driven by the cost of augmenting its network.

Figure 2-5 shows that on a cost per km of line basis, Western Power's forecast capital expenditures are comparable with other transmission network providers[19].

Figure 2-3 – Transmission Capex as a percentage of the capital base



18 Such high forecast expenditures may also be driven by high unit costs. This is not the case, as discussed in section 2.7.2.

19 As most subtransmission lines are installed on poles rather than on towers (and hence have a different cost structure), the subtransmission network layer has been removed in this comparison.

Figure 2-4 – Transmission growth Capex per capital base as a function of demand growth

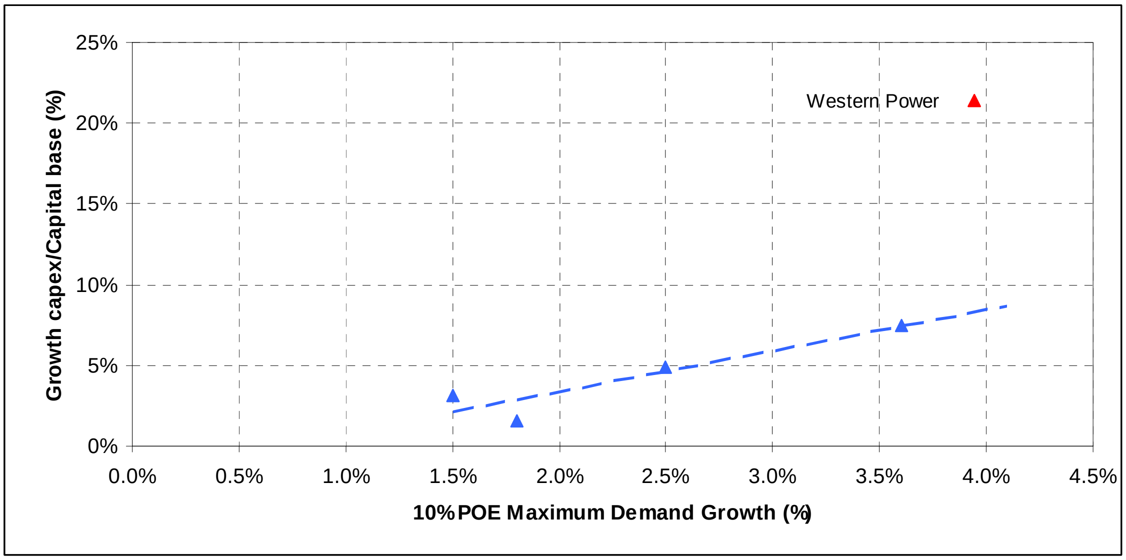
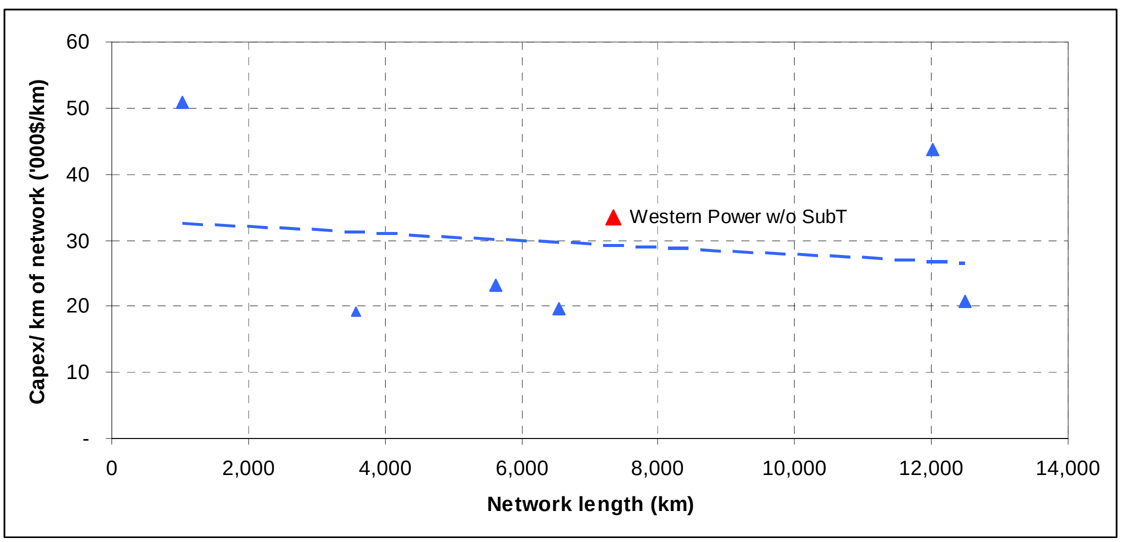


Figure 2-5 – Transmission Capex per km of line as a function of network length



Regarding operational expenditures, Figure 2-6 and

Figure 2-7 show Western Power's Opex is comparable with other transmission network providers. The Western Power without subtransmission data point shown in Figure 2-7 demonstrates that a high proportion of projects forecast for the next regulatory period involve transmission lines rather than subtransmission.

Figure 2-6 – Transmission Opex as a percentage of the capital base

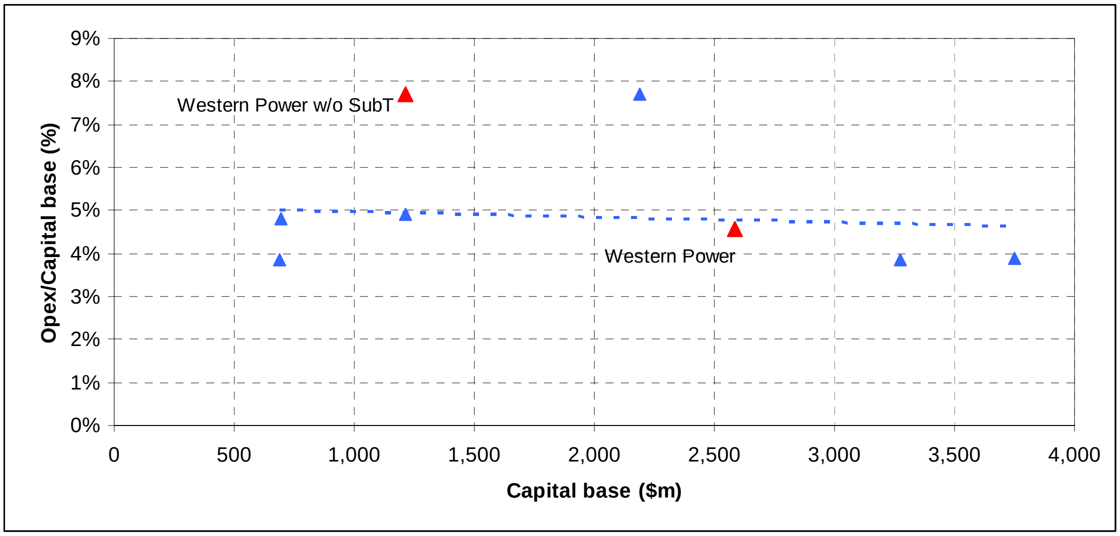
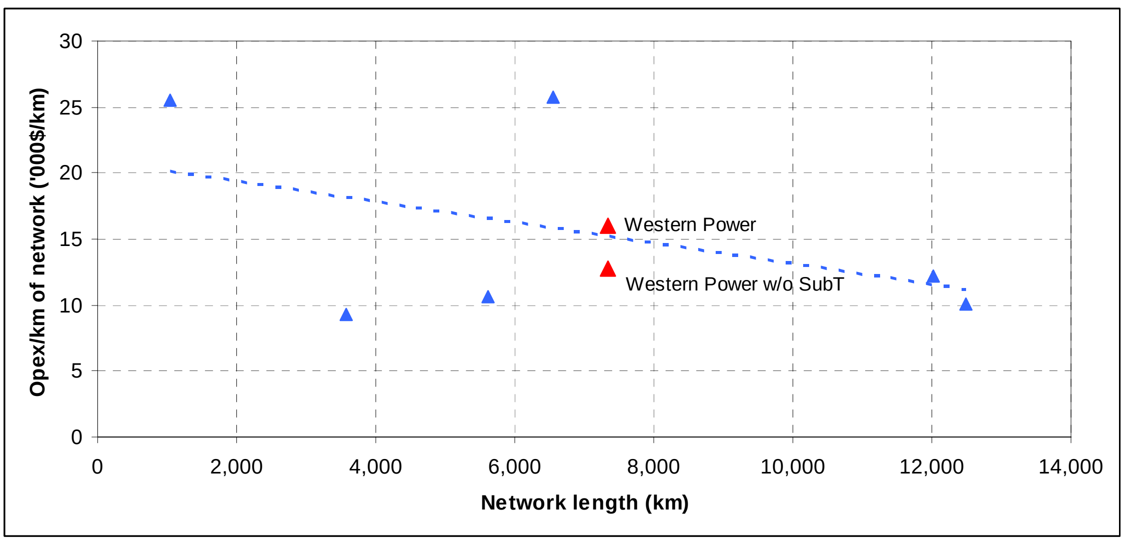


Figure 2-7 – Transmission Opex per km of line as a function of network length



2.7.2 Transmission asset cost benchmarking

SKM was engaged to provide an independent assessment and comparison of a number of selected cost estimates derived from Western Power estimating systems to provide benchmarking with similar utilities in other Australian states.[20] The benchmarking focused

[20] SKM, 2008, *Transmission Asset Cost Benchmarking (DMS 4833261)*

on the transmission network, given the importance of accurate unit costs in forecasting the expenditure for the large transmission projects contained in the works program proposed for the next regulatory period.

SKM noted that benchmarking of cost estimates between states is problematic in the current period of growth in construction activity. Rawlinsons 'Australian Construction Handbook – 2008" comments in relation to Perth that *'The continued high level of activity in commercial and residential sectors continues to place demands over sub-contract resources; these prices continue to rise, although at a slower rate. There appears to be no shortage of public and government building projects which is fuelling the uncompetitive and erratic tender market...'*.

In Perth and in other major cities, the building price index has grown faster than the CPI. In addition, due to the size of the state, Western Australia has a larger regional cost variation than many eastern states[21]. Within the Western Power transmission network the regional variations for building costs are: Geraldton 1.1, Kalgoorlie 1.35 and Albany 1.15 compared to Perth 1.0.

Table 2-1 – Transmission asset cost benchmarks

Category	Item	WP estimate	SKM estimate	Variation
Substation	1. Zone substation 132/22kV stage 1: 1 transformer, 2 lines and 1 indoor switch board	$6,500k	$7,100k	-8%
	2. Additional transformer into a zone substation	$3,300k	$3,660k	-10%
	3. Additional line into a zone substation	$950k	$920k	+3%
	4. 132kV terminal yard: 1 full 1 ½ bay consisting of 3 CBs	$4,579k	$5,270k	-13%
	5. 330kV terminal yard: 1 full 1 ½ bay consisting of 3 CBs	$8,922k	$7,910k	+13%
Lines	6. 132kV wood pole line, 20 km length*	$340k/km	$281k/km	-7%
	7. 132kV single circuit steel pole line, 100km length	$569k/km	$410k/km	+39%
	8. 132kV double circuit steel pole line, 100km length	$716k/km	$643k/km	+11%
	9. 330kV double circuit tower line, 100km length	$900k/km	$914k/km	-2%

*Notes: *This line span is considered to be not feasible for this pole type in an urban location.*

The cost estimates for a number of Western Power infrastructure projects were compared to the costs of similar projects in other Australian utilities. After analysis and a subsequent review of Western Power cost estimates, the following conclusions can be drawn:

21 Rawlinsons 2008, p.30

- the cost estimates for Western Power substations are closely aligned with those in other states
- line construction costs show a higher degree of variability to the SKM benchmark than substation costs
- there is a general industry trend away from wooden poles lines due to the availability and increased cost of suitable timber species, particularly for long lengths
- the design specification for the wooden pole line (Item 6) may be unfeasible due to the required span length of 200 meters
- Western Power adopted a "worst case" assumption for soil conditions for the purpose of budget estimating. This is a valid approach given the characteristics of soils in the region. A review of benchmark cost estimates shows that pole based line designs as opposed to lattice tower designs are more impacted by soil types and cost estimates demonstrate a higher degree of variability to soil types for pole designs
- different assumptions in relation to soil type will markedly affect benchmark estimates
- item 7 is estimated at $410k per km. Different assumptions with regard to these factors could result in a benchmark estimate up to $600k per km or close to the Western Power estimate. The benchmark study was based on a range of project estimates and a range of soil types along a line route
- the benchmark study indicated that the costs of double circuit vs. single circuit lines was consistently close to 1.5. In Western Power estimates the ratio is 1.25. It is assumed this is due to the assumption of worst case soils and the proportion of footing costs to total line cost estimates.

2.7.3 Financial performance comparators – distribution

PB also undertook comparisons for the distribution network. The difference in definitions about the sub-transmission network layer discussed in section 2.7.1 is also relevant here and comparators are shown in this section with and without the subtransmission network layer as appropriate. Because businesses treat public lighting and metering in a variety of ways, the comparisons are made without these.

In addition, some distributor's subtransmission lines operate at higher voltages than others. Those that operate at 132kV may be more cost efficient than those that operate at 66kV. To ascertain if this is a factor, the comparisons identify the typical voltage used at the sub-transmission level.

The distributors in the comparison are Country Energy (132kV), Ergon (132kV), Powercor (66kV), ETSA Utilities (66kV), SP AusNet (66kV), Energex (132kV), Integral Energy (132kV), EnergyAustralia (132kV), AGLE (66kV), United Energy (66kV), CitiPower (66kV) and Western Power (132kV)[22].

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22 Tasmanian data was not included in the sample due to the difference in operating voltages between Tasmania (11/33kV) and distributors in all other states which operate up to either 66kV or 132kV.

Figure 2-8 – Distribution Capex as a percentage of the capital base

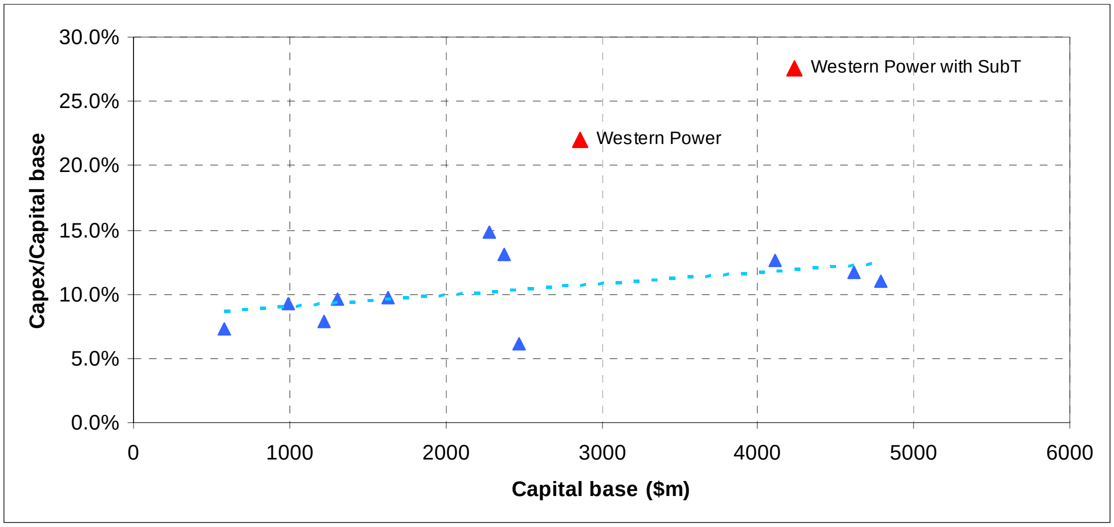


Figure 2-8 shows the distribution Capex as a percentage of the capital base. With or without the subtransmission layer, Western Power's distribution Capex expressed as a percentage of its capital base is considerably greater than other distributors. This is largely due to the 'catch up' expenditure required to meet regulatory obligations and the impact of the large cost uplifts being experienced in Western Australia due to the economic boom. These factors are further discussed in section 3.

Figure 2-9 and Figure 2-10 show that Western Power's distribution Opex is higher as a proportion of its capital base but is comparable with that experienced in other parts of Australia per unit length of the network.

Figure 2-9 – Distribution Opex as a percentage of the capital base

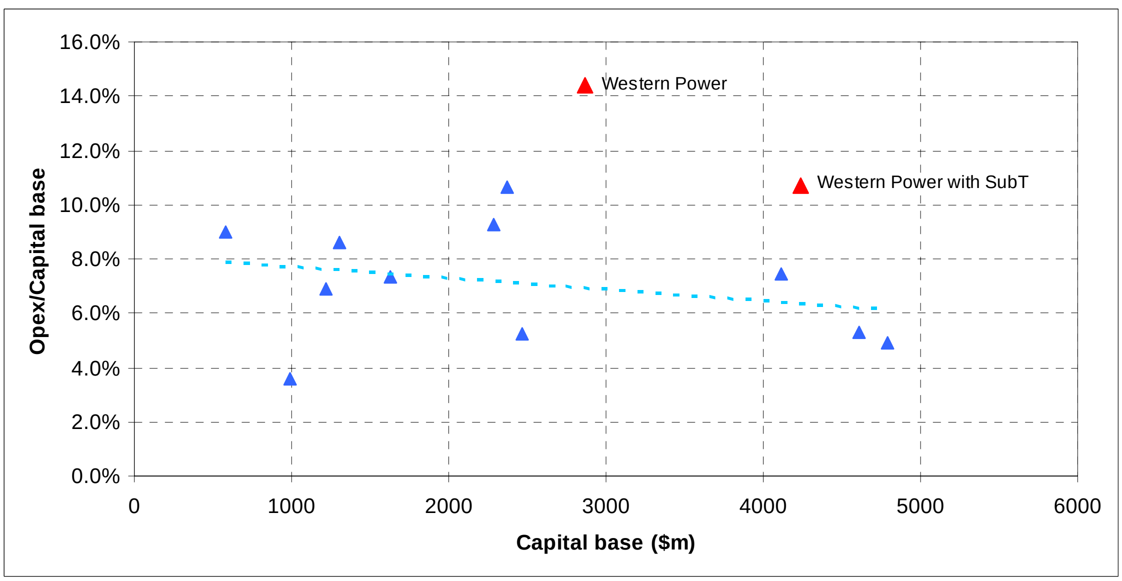
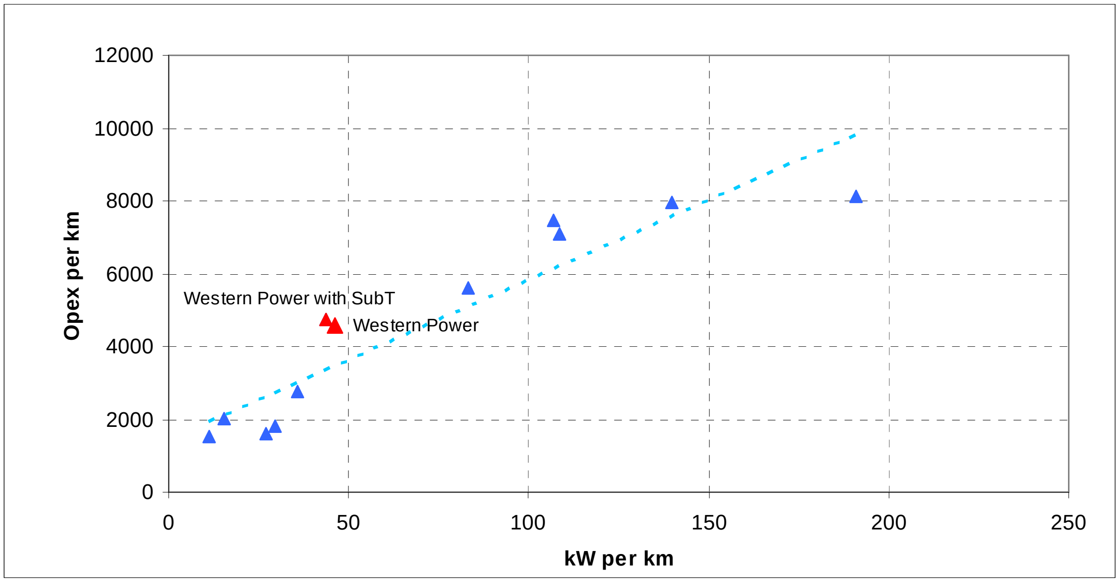


Figure 2-10 – Distribution Opex per km of line as a function of load density



3 Expenditure Drivers

This section summarises the key drivers for change in expenditure levels from those experienced in recent years. It provides a background for the following sections, which set out the detailed expenditure requirements for the next regulatory period.

3.1 Growth in electricity demand – including area based assessment

The economic growth in Western Australia over recent times, and the challenges this presents in the context of Western Power's transmission and distribution network development, is captured within the demand and energy forecast methodology and the resulting projections.

In particular, in order to indentify network constraints and the prevailing augmentation needs, Western Power requires specific forecasts for each substation and terminal station. The most onerous conditions are experienced during summer when demand is high and the transfer capacity of the network is reduced. The forecasts are updated annually and documented within the *Summer Load Trends for the SWIS (Substation and System Peak)* report and are based on statistical analysis of historical information, plus targeted information pertaining to changes in loads at a substation level.

The forecasts used to develop Western Power's transmission Capex projections for the 2009/10 to 2011/12 regulatory period are developed on the basis of a 10% Probability of Excedance **(PoE)** under the 'expected'[23] economic growth scenario. These forecasts align with the 2007 Statement of Opportunities **(SoO)** report prepared by the Independent Market Operator. Distribution Capex projections for capacity expansion projects are based on a 50% PoE demand forecast and the application of this forecast at the high voltage distribution feeder level.

The coincident system peak demand forecast is used to establish the network development plans for the bulk transmission network and each of the defined 13 transmission load areas, while the individual substation (non-coincident) peak demand forecasts are used to develop zone substation augmentation needs[24].

The coincident system peak demand forecasts are summarised at an area level in Table 3-1.

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[23] 50% PoE and 90% PoE forecasts are produced to capture the sensitivity to ambient temperature, while High and Low economic growth scenarios are also established to test the sensitivity to macroeconomic influences.

[24] It is noted that within the SWIS load regions, the diversity factor between the coincident system peak demand and the summated non-coincident substation peak demand is approximately 0.92.

Table 3-1 – Area-based demand forecasts (MW) used to develop the 2009 regulatory period Capex projections.

Area	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Bunbury	290	303	318	332	351	359	390
Cannington	289	332	333	364	374	384	392
East Country	107	122	129	134	163	168	172
Eastern Goldfields	90	105	116	120	124	128	132
East Perth	325	359	350	363	371	378	386
Guildford	146	178	170	179	173	179	185
GT	0	0	30	34	39	43	47
Kwinana	281	311	319	348	363	376	369
Muja	142	143	303	310	319	326	332
North Country	166	163	181	180	187	197	209
Northern Terminal	786	896	968	1,011	1,055	1,098	1,138
South Fremantle	203	230	243	257	265	273	281
South Terminal	352	389	407	423	417	431	446
West Terminal	182	193	184	175	183	192	200
Total	3,724	4,052	4,229	4,382	4,531	4,678	4,836
Growth	10.8%	8.8%	4.4%	3.6%	3.4%	3.2%	3.4%
IMO 10%PoE, expected economic growth	3,800	4,086	4,233	4,361	4,505	4,633	4,746

3.2 Connection of new generation

At a high level, the key drivers for new generation development include factors such as the need to supply increasing loads whilst maintaining sufficient reserve margins, the need to replace aging plant, and the economics of replacing less efficient plant with that offering lower overall energy costs.

In order for Western Power to establish a reasonable and technically robust transmission and distribution development plan, it has established a program of generation development based on the demand forecasts and market conditions. This is heavily informed by the IMO's 2007 SoO report – which specifically addresses the supply demand balance within the SWIS over a ten-year outlook period.

The process undertaken by Western Power to establish a suitable generation development plan has captured the following principles, in order of priority:

- projects that have been assigned capacity credits as part of the Reserve Capacity Mechanism process have been included
- committed projects, those for which an access agreement has been signed, have also been included
- if additional generation capacity is required in order to maintain the appropriate minimum reserve margin, projects in the access application queue are given the next priority, and they are further prioritised based on Western Power's perception of the

probability of the project proceeding – based on their size and the surrounding area impacts

- if even further generation capacity is required beyond that available in the access application queue, additional generation is added to the base case. In this case the location is selected, given known proposals and knowledge of factors such as fuel availability
- relatively small capacity projects that do not (materially) contribute to improving the supply-demand balance. Those whose location are such that the cost of connection is likely to be prohibitive are excluded
- intermittent generators (wind turbines or solar) are included based on a capacity factor of 10% of their nameplate rating.

The outcome of Western Power's application of this methodology is outlined in Table 3-2. It can be seen that there is some retirement of existing generation plant and the assumed development of around 1,700MW of new generation capacity required prior to summer 2012/13.

Table 3-2 – Generation development program (MW) underpinning Western Power's transmission development analysis

Area	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Existing generation	3931	3931	4266	4646	4866	4946	5246
Known retirements							
Kwinana B		(189)					
Kwinana A			(199)				
Committed generators							
Bluewaters 1		204					
New Gen Kwinana		320					
Bluewaters 2			204				
New Gen Neerabup			330				
Manjimup Biomass			45				
Proposed generators							
Collie Region				220			
Kwinana Region					80		
Collie Region						300	
Demand side response	131	118	79				
Total supply	4,062	4384	4725	4866	4946	5246	5246
Actual margin	262	298	492	505	441	613	500
Target margin	340	356	376	376	376	376	376
IMO 10%PoE, expected economic growth	3,800	4,086	4,233	4,361	4,505	4,633	4,746

As part of Western Power's analysis, the Bluewaters generators are to be connected at 330kV to the Bluewaters switchyard located in the Collie region, New Gen Kwinana is to be connected at 330kV to the Kwinana switchyard, New Gen Neerabup is to be connected at

330kV to the Neerabup switchyard, and the Manjimup Biomass is to be connected at 132kV to the Manjimup substation. As for generation beyond 2009/10, it has been assumed that generation will be located in the Collie and Kwinana regions. Generation in the Collie region is assumed to be connected at 330kV while generation in the Kwinana region is assumed to be connected at 132kV.

Western Power currently has a significant number of enquiries and applications for capacity totalling a few gigawatts of generation. These proposals are spread throughout the SWIS. Consequently, the actual generation sites that will proceed are dynamic and could easily be different to the scenario assumed above, resulting in the need for different/additional network reinforcements.

3.3 Replacement of network

Replacement of the distribution network comprises a 'long term' view with actual replacements based on asset specific condition assessments. Some assets are nominated to run to failure **(RTF)** as it is not efficient to instigate a maintenance, condition assessment and asset replacement programme for such assets (e.g. cable joints).

The long term view takes into account the nominal, expected and extended lives of an asset. The nominal, expected and extended lives of an asset are based on life cycle data (which takes into account serviceability, operations, enhancements and local conditions). These lives have been developed from Western Power's experience, and from comparisons with the extended life practices of other utilities which were found to be comparable.

Western Power has recently undertaken a more sophisticated modelling approach for critical assets to help verify the values for nominal, expected and extended lives. The predictive model uses a stochastic methodology based on Weibull distributions to produce probabilistic failure curves. With this approach, in combination with the current replacement rates, it is possible to better predict the long term asset replacement requirements.

Replacement requirement curves (averaged over a five year period for planning and financial purposes) minimises the spending and resource peaks that arise from the distribution assets installation profile.

In comparison to the current methodology used by Western Power, it can be shown that the nominal life of an asset is where 50% of the population is expected to have failed, whilst the extended life is where 95% of the asset population is expected to have failed. In the case of wood poles, the extended life is estimated to be 55 years instead of the 60 years currently nominated as shown in Table 3-3. Long term asset replacement requirements are based on the replacement of assets that have reached their extended lives, and are condition assessed before replacement to maximise capital return. The table below shows the nominal and extended asset lives for non-RTF assets.

Table 3-3 – Asset life and average age of key assets (2006/07 values[25])

Asset Description	Nominal Asset Life	Extended Asset Life
Auto transformer	35	45
Capacitor bank	35	45
Disconnector, HV overhead	35	50
Drop out fuse	30	35
Fuse disconnector overhead	35	45
Fuse disconnector underground	35	45
Fuse switch	35	50
H.V. cable pole termination	30	50
Low voltage distribution frame	35	50
Austpole reinforced wood pole	55	55
Pole top switch disconnector	35	35
Wood pole^^	30	60*
Reactor	35	45
Recloser	35	45
Substation	35	50
Surge diverter	30	35
Sectionaliser	35	50
Switch disconnector	35	50
Distribution transformer	35	45
Carrier – underground	65	65
Carrier – overhead	55	55

* Note: Current studies indicate that this may reduce to 55 years

For the immediate to short term (to the end of the next regulatory period), the replacement rates are based on the clearing of the backlog, expected condemnation rates and asset serviceability. These condemnation rates are embodied in the asset specific asset missions, whereby asset serviceability looks at the loading of an asset at a specific point in the network and provides a means of prioritising the order in which specific assets are replaced.

Western Power's SWIS Distribution Asset Management Plan targets 21 non-RTF asset classes, as listed in Table 3-3, for specific replacement strategies that involve the condition monitoring and replacement approach.

25 These are the 06/07 values using data to September 2007, account is yet to be taken of assets installed in the system since this date.

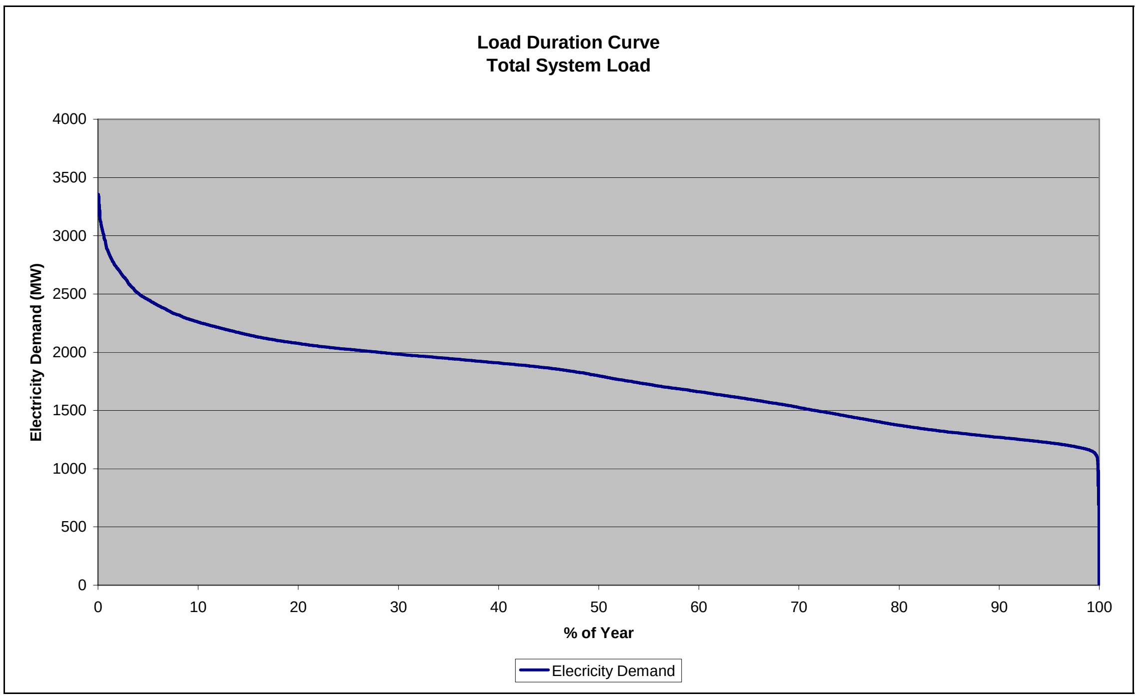
3.4 Distribution feeder load reduction strategy

In the metropolitan urban areas, growing load growth over the regulatory period will increase feeder loadings and if unchecked will result in loadings on distribution substations and their supplying HV feeders that exceed optimum levels. The establishment of new zone substations, and the transfer of large amounts of existing network load to these substations, will partly address these issues by allowing new distribution feeders to be created that can supply the increased number and capacity of distribution substations. In addition to this, new feeders and feeder upgrades from existing substations are to be constructed to manage the growth of load in specific areas.

Western Power's planning criteria for urban areas requires (in part) that feeder peak loads are kept below 80% of their Normal Cyclic Rating **(NCR)**. This criterion ensures that in the event of a network fault, network operators can restore supply by transferring the faulted feeder onto adjacent feeders[26].

Many metropolitan urban HV distribution feeders currently have loadings (measured by the utilisation of the feeder) that exceed the planning criteria. Figure 3.1 shows the total network load duration 2007/08.

Figure 3-1 – Total network load duration (2007/08)



26 For metropolitan distribution planning standards refer to DMS 4489792. For country distribution planning standards refer to DMS 4504167.

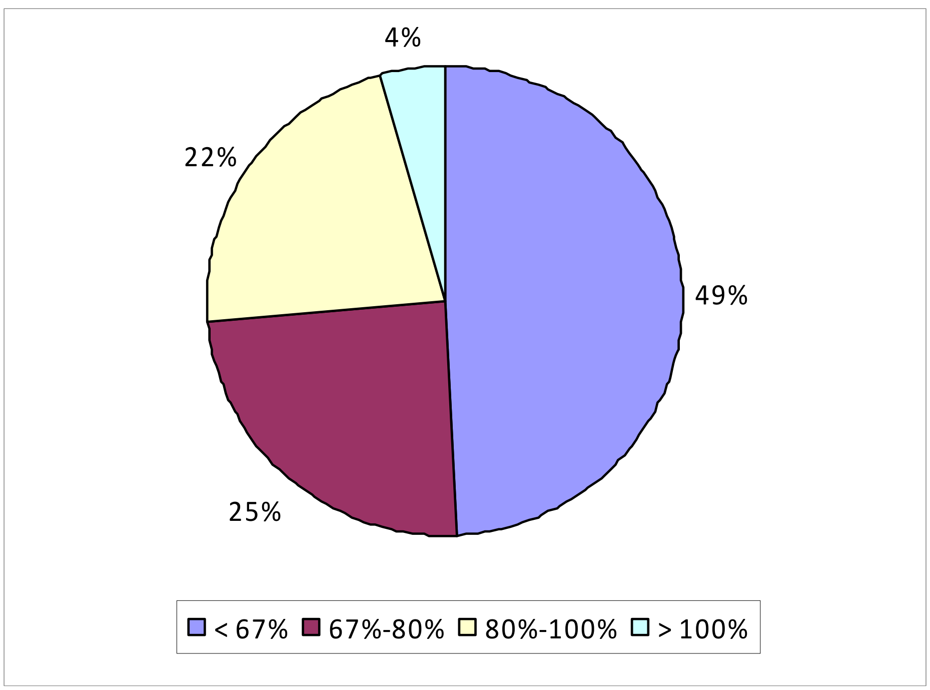
Figure 3-2, Figure 3-3 and Figure 3-3 show the proportion of feeders in each utilisation category across the SWIS for the metropolitan and country areas respectively. It can be seen that there are a significant proportion of feeders in the metropolitan area that exceed the planning criterion limit of 80% (22% or 107 feeders) at the time of feeder peak demand as a result of load growth and the current network configuration. This situation complicates network switching arrangements and in some instances feeder switching in the event of a fault is not possible due to feeder over-utilisation.

This increases network operating costs, limits supply restoration capability and increases the fault outage duration for customers. Controlling operating costs and improving distribution network supply reliability are key drivers and Western Power is taking action to reduce the over-utilisation of distribution feeders to more manageable levels over the regulatory period.

In the case of rural HV distribution feeders, voltage constraints also add to existing capacity constraints. In the North Country and South Country respectively, 33 of the 109 feeders and 31 of the 78 feeders have voltage constraints. This further reduces the backup capability available from adjacent feeders under network fault conditions.

The specific strategies outlined in Section 10 of this document target distribution feeder over-utilisation through increasing feeder capacity, and enable load transfers that will result in utilisation levels progressively moving towards the requirements of the established planning standards.

Figure 3-2 – Metropolitan feeder utilisation[27] (2007/08 peak load data)



[27] Data excludes CBD feeders

Figure 3-3 – South Country feeder utilisation (2007/08 peak load data)

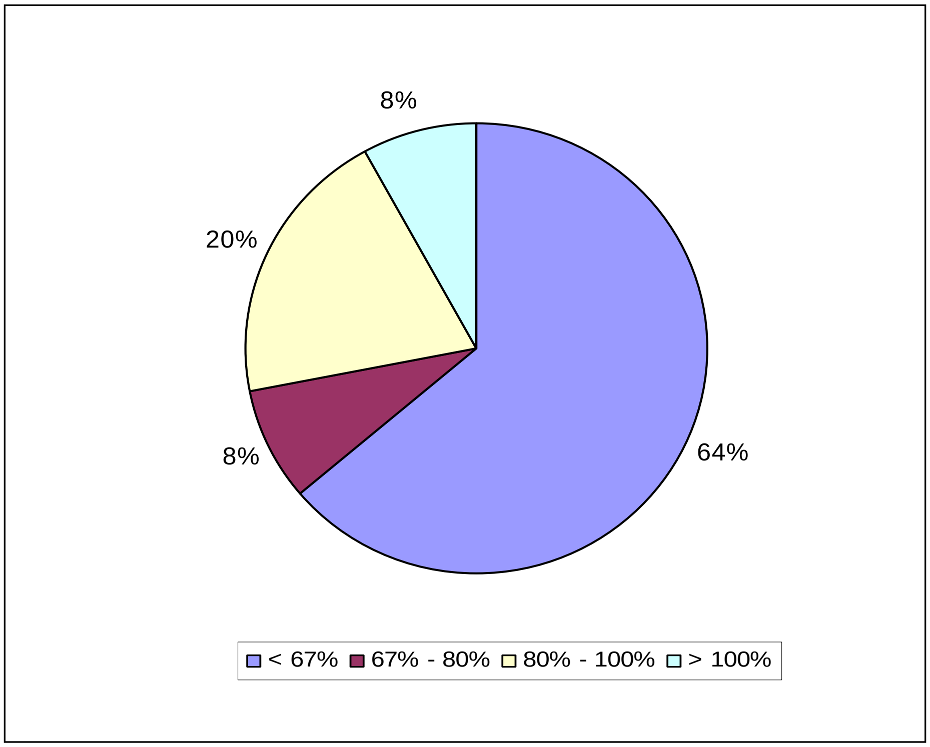
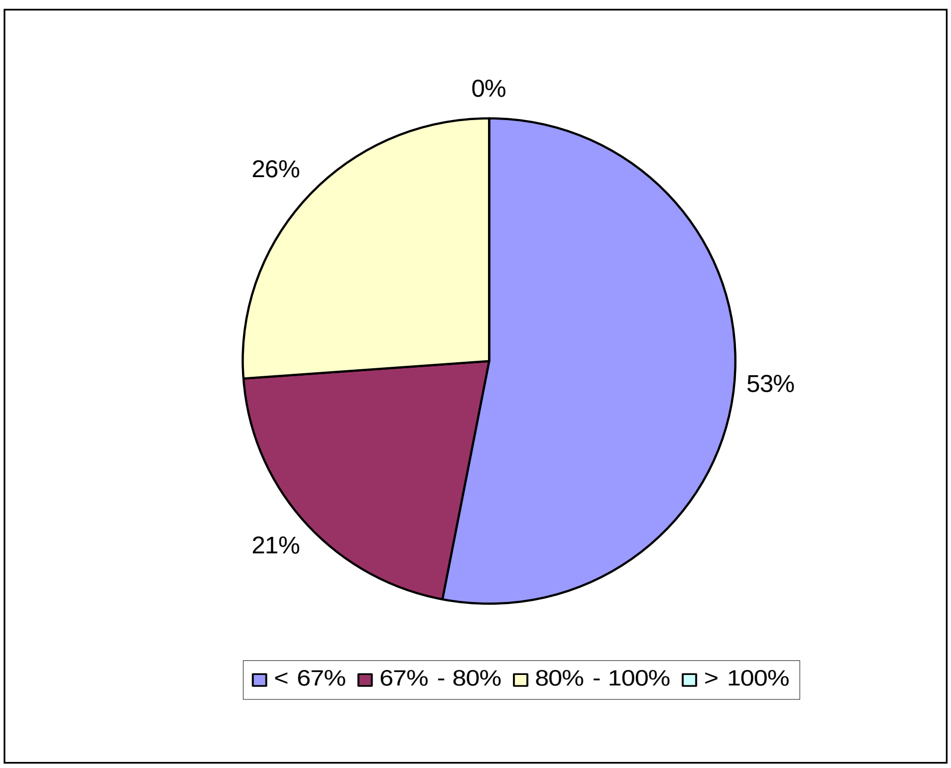


Figure 3-4 – North Country feeder utilisation (2007/08 peak load data)



3.5 Increasing backlog due to constrained expenditures

The growth in demand for electricity in the current regulatory period has been higher than forecast. This has resulted from an increased in the number of customer connections and network capacity augmentations.

Western Power has responded to this situation by increasing its internal and contracted workforce. This increase however, has been insufficient to provide for all required works and priority has had to be given to customer and demand driven works. As a result, the volume of some other works, including asset replacement and reliability improvement works, has been less than required by the relevant maintenance policies and improvement strategies. This backlog of work if left unchecked will result in decreased service levels.

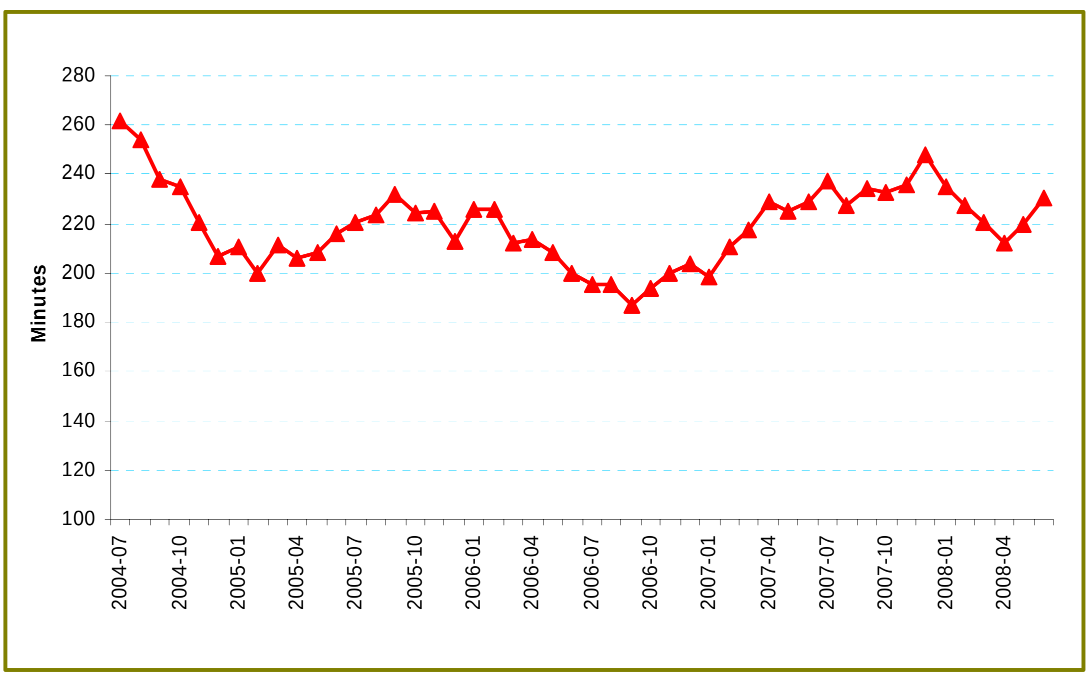
In conjunction with plans to further increase its workforce (refer section 2.6) the expenditure forecast for the 2009/10 to 20011/12 regulatory period allows the backlog to be reduced to prudent levels.

3.6 Past reliability performance - distribution

The principal measure of performance of an electricity distribution network is its level of reliability. The *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* sets supply reliability standards that Western Power must use all reasonable endeavours to meet. The Code is silent on the timeframe for attaining these standards.

Western Power's network does not meet the reliability standards set out in the Code. In the current access arrangement, Western Power set a target reliability improvement of 25% of the performance gap, with the improvement being implemented in stages over a 4 year period commencing during 2005/06.

Figure 3-5 – Distribution network, unplanned SAIDI (12 month rolling average)



Note: Excludes major event days and interruptions from customers, generation and transmission

Figure 3-5 shows that Western Power's reliability performance in 2006/07 and 2007/08, as measured by unplanned SAIDI on a rolling 12 month average basis, has not improved significantly over historical levels[28]. While some reliability improvement works have been undertaken, a higher than forecast level of customer works in these years has prevented Western Power from fully implementing its reliability improvement works program, with available resources being allocated to higher priority customer works. Small improvements are expected in 2008/09 period due to the installation of automated protection switchgear (reclosers and load break switchgear) and targeted maintenance on the worst performing distribution feeders.

Figure 3-6 – Distribution network, unplanned SAIDI contribution by cause

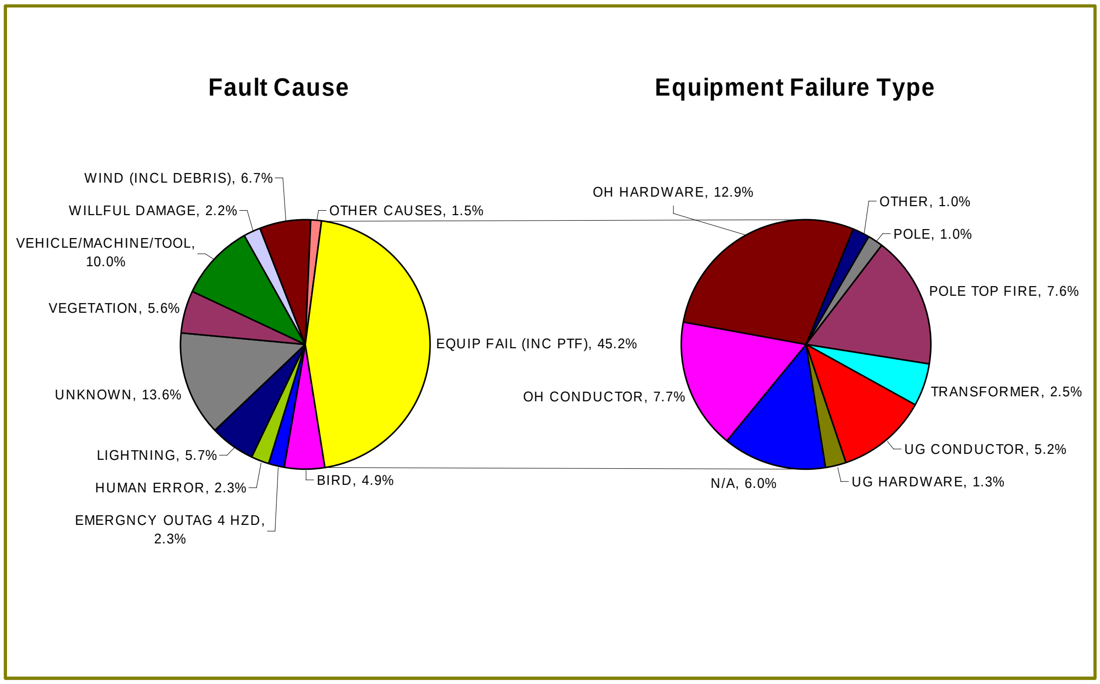


Figure 3-6 shows that equipment failure (including pole top fires) is the largest cause of supply interruptions, accounting for 45% of total network SAIDI.

Table 3-4 shows the legislated targets compared to historical performance levels.

[28] SAIDI is measured using the Steering Committee for National Regulatory Reporting Requirements (SCNRRR) definition and IEEE 1366 *Guide for Electric Power Distribution Reliability Indices* for major event days known as the Beta method. The Beta method is used to identify major event days which are to be excluded from the minimum service standards as per SCNRRR.

Table 3-4 – SAIDI historical performance (Based on the Code methodology)

Feeder type	Target	Historical performance				
		03/04	04/05	05/06	06/07	07/08
CBD	30	44	10	11	33	57
Urban	160	283	283	218	264	269
Rural	290	615	552	462	563	599

For the regulatory period commencing 1 July 2009, Western Power proposes to set a target reliability improvement of approximately 29 minutes (Refer Table 3-7), to be achieved by 30 June 2012. The proposed targets for the next regulatory period are set out in Table 3-5.

These targets balance the need to reach the reliability standards set out in the Code within a reasonable time period, the needs of customers, as determined through surveys and customer feedback, and the practical limitations of delivering a large works program.

Table 3-5 – Unplanned SAIDI (Based on the Code Methodology) forecast performance given average externalities (minutes)[29]

Feeder type	Maximum required	Forecast performance		
		09/10	10/11	11/12
CBD	30	43	43	43
Urban	160	300	278	265
Rural	290	639	602	580

The determination of customer needs is not a simple task; there is a wide diversity in the needs of individuals and customer groups. Western Power has a strong history of surveying customer attitudes and continues to work with customer groups to identify the optimal price/service offering.

Western Power last conducted a substantial survey of customers in 2005. The survey identified the consistency and reliability of supply as the overwhelming issue of importance to them

Table 3-6 shows that over 85% of customers identified “Consistency/reliability of supply” as the principal issue. When surveyed as to whether Quality of Supply was improving, 82% said it was remaining the same or getting worse (Figure 3-7 – Customer perceptions of quality of supply). In addition, when asked about the factors that affect the performance of the network, customers appeared aware of the issues facing Western Power. Western Power concludes that customers would support an improvement in reliability of supply.

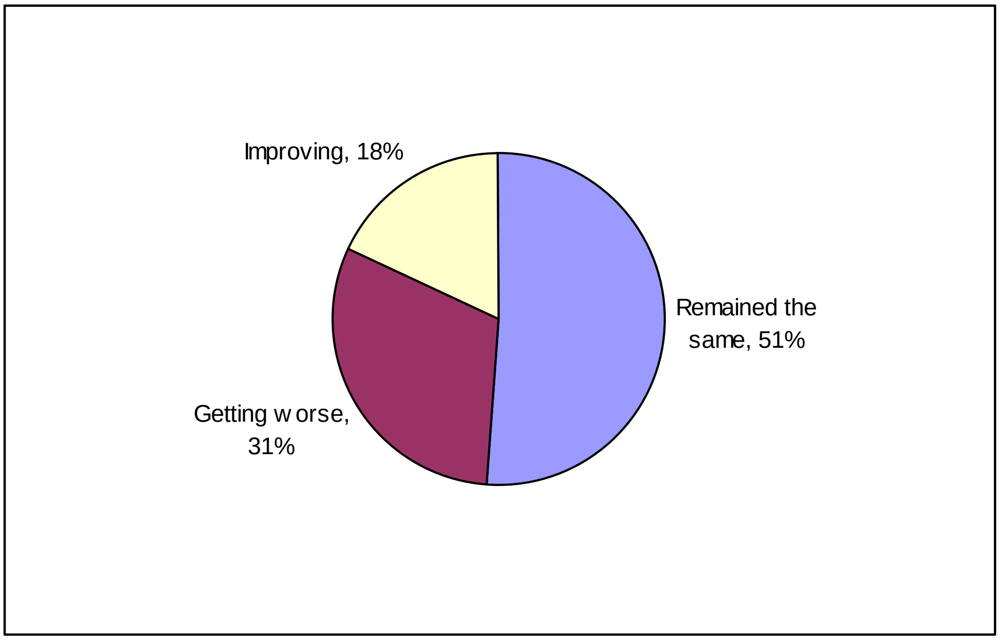
29 Actual and targets in Table 3-5 are based on the Code methodology rather than SCNRRR. The targets in the Access Arrangement information report are based one the SCNRRR methodology which is the methodology Western Power proposes to use going forward.

Table 3-6 – Customer identified issues

Customer identified issue	Respondents %
Consistency/reliability of supply	86
Price	20
Frequency of outages	14
Quality of supply	10
Duration of outages	7
Shortage of supply in future	5
Environmental concerns	4
Other (e.g. customer service, good maintenance and power surges)	5
Don't know	2

Source: Western Power, Market Equity Customer Survey – April 2005

Figure 3-7 – Customer perceptions of quality of supply



Source: Western Power, Market Equity Customer Survey – April 2005

The planned improvements in reliability arise from specific reliability improvement projects and also as a result of other distribution works[30]. Table 3-7 shows how each type of work contributes to the planned improvements.

30 Detail of drivers etc for the improvement in service standards is given in DMS 4294655

Table 3-7 – Planned reliability improvements (based on probability weighting) to 2011/12

Strategy	SAIDI saving minutes pa
RELIABILITY IMPROVEMENT	
- Reliability Improvement Work in 2008/09	5.00
- Targeted reinforcement (Metro)	2.01
- Targeted reinforcement (North Country)	0.24
- Targeted reinforcement (South Country)	0.34
- Automated sequence switching	2.98
- Recloser, load break switch and RMU placement	9.36
- North Country pole reinforcement	0.28
- First section undergrounding	1.14
- Telemetry retro fit	0.25
- Wildlife proofing	0.34
- Lighting mitigation	0.20
- Fault indicators	1.06
- Re-occurring trips management	0.37
- LV networks	1.47
SAFETY	
- “Hills” covered conductors	0.72
- Pole Top Replacement	0.10
- BFMP Wires Down Mitigation	0.73
ASSET REPLACEMENT	
- Pole replacement	0.69
- LV Spreaders	0.01
- Distribution substation replacement	0.04
OTHER	
- SUPP	1.27
- Rural power improvement program (RPIP)	0.42
Total forecast SAIDI saving	**29.0**

The underlying and total forecast SAIDI saving in Table 3.7 is determined to a 90% confidence utilising a Monte Carlo probabilistic model.

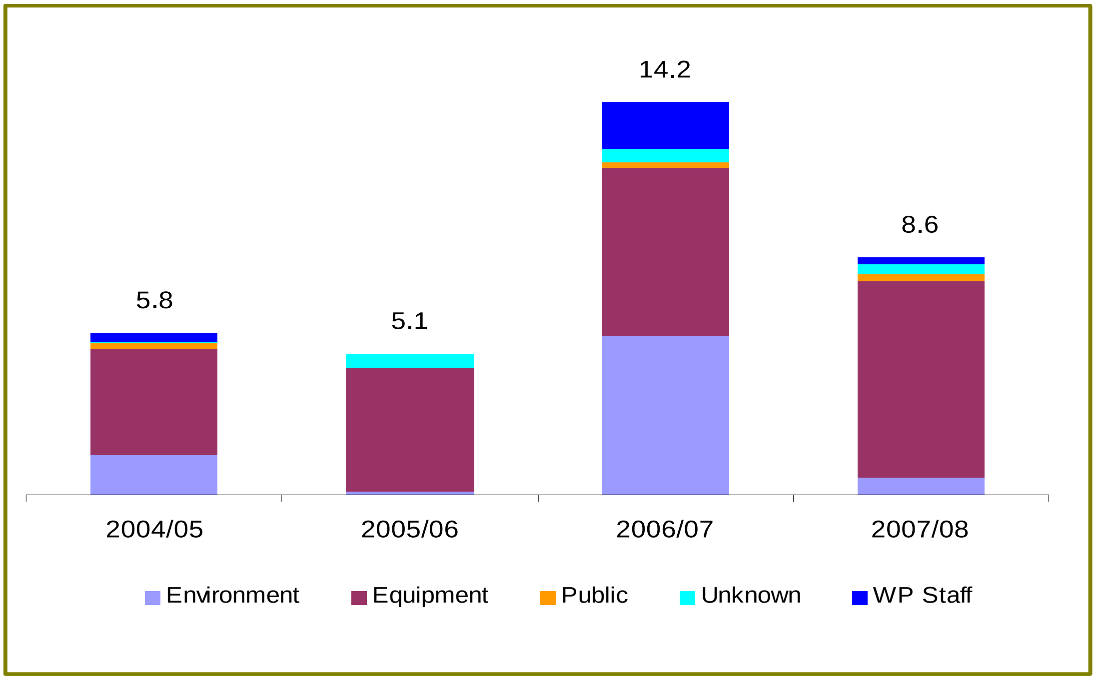
The reader should note that the SAIDI impacts referred elsewhere against individual reliability improvement strategies are expected values.

3.7 Past reliability performance - transmission

The principal measure of performance of an electricity transmission network is its ability to deliver energy to bulk supply points. Western Power has adopted the measure "System Minutes Interrupted" as the most appropriate indicator of its network's performance[31].

Western Power proposes to maintain the performance of its transmission network at current performance levels and has not included specific improvement works in the current works program or that for the next regulatory period. It has set a target of 12.4 minutes. Western Power notes that the measure includes all events on its transmission network. Figure 3-8 shows historical performance against the target varies due to external factors from year to year.

Figure 3-8 – Transmission network - system minutes interrupted



3.8 Meeting other regulatory obligations

Western Power is obliged to comply with a number of safety, environmental, and statutory requirements, particularly in regard to public safety, OH&S, environmental management, and power quality (PQ) codes.

While safety and environmental considerations are already well embedded in Western Power's systems and processes, maintaining compliance and addressing new requirements is an important and ongoing business need. A number of new requirements have been imposed upon Western Power by the Energy Safety Directorate particularly in relation to bush fire preparedness and safety, navigable waterways and substation security. There are also a number of safety and reliability issues that have arisen due to changes in (Australian and/or Industry) standards or specific incidents.

31 Defined as the estimated MWh lost (times 60) divided by the estimated peak load in MW.

Compliance with the requirements of the *Electricity Act 1945*, particularly with the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, as well the *Electricity (Supply Standards & System Safety) Regulation 2001*, and specifically the *Guidelines for the Design, Construction and Maintenance of Overhead Lines 2006* (HB C(b)1), drive much of the distribution Capex under the regulatory compliance category. OH&S matters and compliance with the requirements of the environmental protection regulations, as well as responsible and prudent management of public safety issues are also key drivers of this category of capital expenditure.

Compliance with regulatory obligations is a key driver of Western Power's capital expenditure. Section 7.6 outlines the specific distribution strategies that Western Power has adopted to address these regulatory obligations.

3.9 Smart meter rollout

Consideration is being given at a national level for the introduction of 'smart meters', with current indications being that smart metering will be phased in nationally under arrangements that are yet to be finalised. As issues such as technical standards, funding arrangements, and the timing of a smart meter rollout are yet to be determined, Western Power will not be seeking specific funding for this work in this submission. Rather, once the requirements for smart meter implementation are determined, Western Power will develop a response and seek funding under 'pass-through' arrangements in the Access Arrangement.

3.10 Changes to standards and policies

Concern for the poor operational and safety performance of Western Power's facilities (e.g. distribution HV lines) has necessitated a review to improve and introduce new design and construction standards in recent years. In addition, EPA[32] mandated changes to the environmental standards, for example lower ambient noise emission levels, is also imposing more stringent and costly design and construction outcomes for the business. The additional costs to meet these obligations and outcomes are reflected in forecast expenditures for the next regulatory period. These additional costs are summarised in Table 3-8.

There are a number of other pending changes to national standards and codes that are expected to require more stringent design and construction practices (e.g. C(b)1[33]) that will invariably add further costs. However, as the impact of a number of such needs can neither be qualified nor quantified at this time, it is proposed that these costs be covered by the 'pass through' mechanism when the explicit nature of such changes are known and can be reasonably costed.

[32] Western Australia Environmental Protection Authority

[33] Energy Network Association, *C(b)1: 2006 – Structural and Engineering Standards for HV Transmission Lines*

Table 3-8 – Summary of changes to standards and policies

Change	Driver	Outcomes	Cost (3 yrs) $M
External influences			
Pole embedment depth	Australian standards	Safety	29.62
Stay wire compliance	Australian standards	Safety	7.64
Remote crossings line marker	Australian standards	Safety	7.80
Transformer sound proofing	Legislation/ regulatory	Environmental	18.90
Design of earthing for substations	Australian Standards	Safety	0.50
Substation earthing cost	Australian standards	Safety	1.50
High efficiency streetlights	Stakeholder[34] feedback	Public image, CO_2 reduction	15.05
Load break pole top switches	New technologies	Reliability, efficiency	6.97
Microdots (cable and copper)	Stakeholder feedback	Theft	0.15
Internal influences			
Bonding	Work practices	Reliability	7.6
Transformer DRCM	Performance drivers	Reliability	11.31
New ring main units with DRCM	Performance drivers	Reliability	15.39
Larger underslung earth wire	Performance drivers	Safety	0.42
Surge diverters	Performance drivers	Reliability	0.85
(DRCM) capacity banks	Performance drivers	Reliability, PQ, efficiency	2.07
UG fault indicators	Performance drivers	Reliability	5.86
Mini pillars	H,S&E issues	Safety	6.75
Uni pillars	H,S&E issues	Safety	2.25
Total			140.63

Note: DRCM is distribution remote control monitoring; PQ is power quality; H,S & E is health, safety and environment

3.11 Cost escalators

The prices for services, commodities and plant have significantly increased during the current regulatory control period at a faster rate than CPI. In preparation of its submission Western Power engaged the services of Access Economics to undertake a study of the material and labour cost escalation factors[35]. The outcome of this work is summarised in Table 3-9 as are the weighted average escalators.

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34 General Community, Customers, Shire Councils, etc

35 Access Economics Pty Ltd, 2008, *Material and Labour Cost Escalation Factors,* DMS 4575552

Table 3-9 – Cost escalators (nominal)

Cost Escalation Factors	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12
Labour Escalation (%)									
External - WA utilities workers	3.20%	4.45%	4.28%	5.12%	5.84%	4.92%	4.54%	4.12%	4.78%
Internal*	4.00%	4.00%	6.10%	6.10%	5.00%	6.50%	6.00%	6.00%	5.50%
Land Escalation (%)									
Perth	6.47%	8.50%	6.99%	8.70%	8.16%	7.66%	5.32%	5.20%	7.61%
Remainder of WA	5.79%	7.70%	6.91%	8.15%	7.36%	6.90%	4.60%	4.56%	7.02%
Material Cost Escalation (%)									
Concrete	2.74%	2.82%	2.82%	2.62%	3.01%	4.35%	1.11%	2.11%	8.44%
Fabricated steel	3.80%	15.80%	3.68%	1.47%	8.00%	12.17%	3.59%	1.48%	6.80%
Wooden poles	4.13%	1.40%	2.99%	3.41%	2.58%	5.97%	3.43%	2.30%	6.55%
Electrical cable	1.66	11.37%	15.19%	40.74%	-1.01%	8.92%	4.60%	2.00%	6.82%
Raw copper	47.18%	34.83%	58.77%	40.53%	0.39%	-5.97%	-9.94%	-8.17%	-6.92%
Raw aluminium	15.63%	15.13%	23.57%	23.57%	-6.18%	-0.34%	-0.17%	-2.93%	-2.73%
Electrical and control equip.	0.43%	1.62%	5.30%	5.30%	5.59%	10.80%	3.13%	1.14%	6.01%
Lights	-1.62%	-1.74%	3.12%	3.12%	5.07%	8.51%	2.28%	0.35%	5.07%
Nuts, bolts, screws	-0.25%	-1.09%	5.29%	5.29%	0.22%	5.62%	0.53%	-1.67%	3.16%
Earthworks	4.07%	4.16%	5.92%	5.92%	4.75%	4.76%	2.74%	2.75%	6.14%
Sheet metal	1.49%	4.47%	8.63%	0.69%	4.33%	10.67%	1.83%	0.49%	5.57%
Combined Material Escalators (%)									
Transmission operating	1.12%	4.54%	8.29%	17.33%	2.29%	9.35%	3.60%	1.43%	6.23%
Transmission capital	0.71%	3.44%	7.28%	13.33%	3.66%	10.16%	3.49%	1.36%	6.20%
Distribution operating	0.94%	2.16%	5.36%	6.80%	3.87%	9.13%	2.98%	1.04%	5.83%
Distribution capital	1.12%	5.56%	9.04%	19.96%	1.95%	9.40%	3.74%	1.48%	6.32%
Weighted Average % (Nominal)									
Transmission Operating	3.12%	4.29%	5.75%	7.82%	4.84%	6.38%	4.93%	4.34%	5.34%
Distribution operating	3.01%	3.66%	5.41%	6.00%	4.95%	6.78%	4.83%	4.23%	5.38%
Transmission capital	1.77%	3.76%	6.40%	10.35%	4.37%	8.39%	4.09%	2.67%	5.76%
Distribution capital	2.58%	4.78%	6.66%	11.31%	4.07%	7.12%	4.60%	3.55%	5.58%
Inflation (CPI)	2.48%	2.49%	3.98%	2.07%	4.51%	2.98%	2.47%	2.59%	2.70%

* 2008/09 through to 2011/12 provided by Human Resources Division

3.12 Estimating risk factors

Western Power's cost estimating process involves feedback on actual costs and detailed project reviews. Through these processes, it is evident that cost increases and decreases occur that cannot be foreseen at the time of cost estimation. Factors such as small changes in project scope occur, for instance, as a result of a more extensive planning approval processes.

To identify an appropriate allowance in forecast expenditures for small errors in cost estimating, Western Power engaged consultants Evans & Peck to develop a strategy dealing with the asymmetric quantitative risks associated with estimation and delivery of transmission and distribution Capex over the 2009/10 to 2011/12 regulatory period. Based on Monte Carlo analysis, the consultant determined risk factors for IAM and non-IAM projects. Application of the risk factor to IAM projects gives the highest probability of appropriate cash flows and reduces the likelihood of the need for subsequent price adjustments.

On the basis of this analysis, Evans & Peck recommends[36] that Western Power include a "global" risk allowance of 3.5% in their expenditure forecasts. Due to the non deterministic nature of risk expenditure, Western Power has incorporated the consultant's recommendation into its forecasts by adding a separate line item to each relevant high level regulatory category for its transmission and distribution Capex forecasts[37].

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36 Evans and Peck, 2008, *Quantitative risk assessment of capex and opex expenditures*, part 1 DMS 4783411 and part 2 DMS 4783429

37 Refer to table 5-1 and 6-5 respectively

4 Corporate Support Costs

In this section, we set out the costs required to provide key corporate functions to the operational divisions.

4.1 Overview

Western Power's support areas are managed in a way that facilitates the most effective means of providing key corporate functions to the operational divisions. This has meant a restructure in some areas, as efficiencies and synergies are maximised to provide support as needed to the business. As the operational divisions underwent a reorganisation, so too has the support area's focus shifted to better align with the business' changing needs.

The new structure within Western Power sees the operational divisions of Customer Services, Service Delivery and System Management supported by the corporate areas. A brief summary of the operating divisions is provided below:

- the Customer Services Division **(CSD)** is responsible for asset planning, performance, design and engineering of the SWIS. This includes expanding and improving the network. CSD also manages Western Power's major customer interface with generators and retailers and has a strong customer focus. This division also includes the Environment and Land Management and Customer Assistance branches.
- the Service Delivery Division **(SDD)** is responsible for managing the delivery of the Works Program, through a balanced portfolio of internal workforce, Alliance partners and contractors. It brings together engineering, program management and the operational workforce into fully integrated delivery teams. The division is organised into two distinct operational groups, split under transmission and distribution
- the objective of the System Management Division is to ensure sufficient generation capacity, system integrity and configuration to meet the predicted load and to provide centralised control and access to the wires business.

Western Power's support divisions comprise of Finance, Human Resources, Strategy and Corporate Affairs, Legal and Governance and Chief Executive Officer. Together they provide a committed and comprehensive suite of core functions which help to ensure safe, reliable and efficient operations across the organisation. They also provide guidance and leadership for the organisation as it progresses towards the strategic goal of becoming an energy solutions business, while ensuring key organisational values underpin everything Western Power does.

The support costs as shown in Table 4-1 and Table 4-2 are fully comprehensive, and cover both the transmission and distribution businesses. An allocation across the two business lines is assumed, based on the percentage of labour and materials for the non support activities in the overall distribution and transmission forecast. The resulting allocation of overall business support costs is approximately 75% to distribution and 25% to transmission. Consistent with the work program categories, escalations have been applied to the costs noted in the support areas for future years, as per Access Economics.

Table 4-1 – Transmission business support costs ($M)

	09/10	10/11	11/12
Opex ($M)	27.39	28.04	28.70
Capex ($M)	21.15	18.84	9.31

Table 4-2 – Distribution business support costs ($M)

	09/10	10/11	11/12
Opex ($M)	76.58	78.70	80.80
Capex ($M)	62.21	54.90	26.93

4.2 Opex

Business support operating expenditure relates to the expenditure for the upkeep of Western Power's amenities, processes and governance liabilities needed to effectively run the business. It sustains the functions of the support areas that do not directly relate to the operation of the network or the management of system assets.

The business support areas include the Finance, Human Resources, Legal and Governance, Strategy and Corporate Affairs, the Office of the Chief Executive Officer and the Customer Call Centre.

The business support operating expenditure also covers expenditure for insurance, extended outage payments, the energy safety levy, rates and taxes, fringe benefit tax and the design and estimating costs for customer work that is not asset related.

Figure 4-1 – Business support overview Opex ($M)

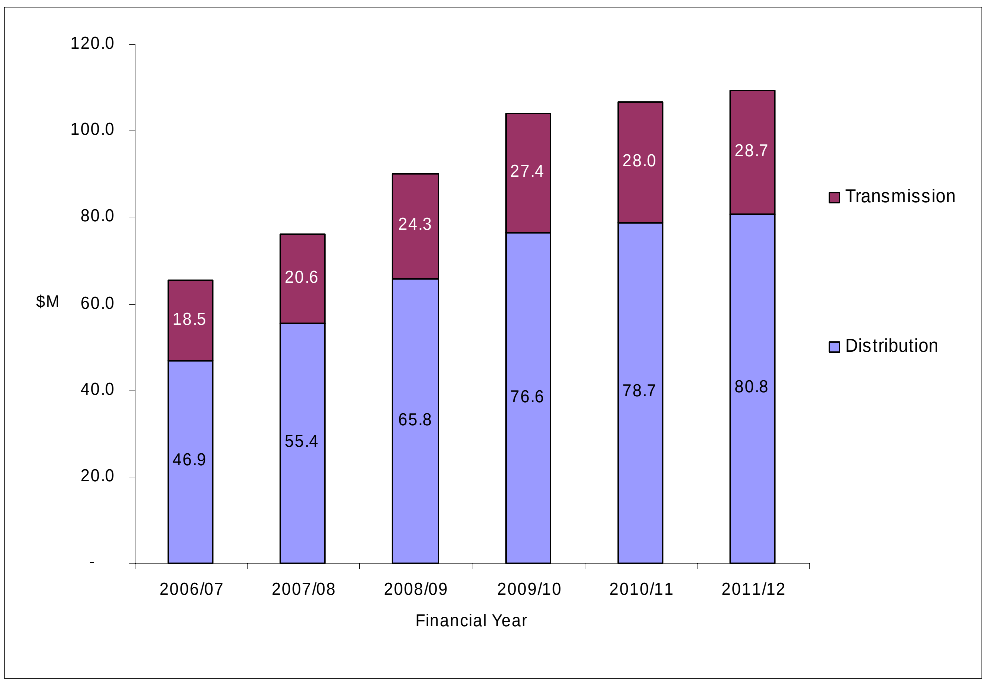


Table 4-3 – Business support costs Opex ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Distribution Opex ($M)	46.95	55.35	65.82	76.58	78.70	80.80
Transmission Opex ($M)	18.54	20.63	24.30	27.39	28.04	28.70

Unless otherwise specified, the increases in support areas forecast for the next regulatory period are due to escalations, as provided by Access Economics.

4.2.1 Human resources

The objective of the Human Resources Division is to develop the HR strategies and systems to ensure Western Power's ability to attract, develop and retain a talented workforce with the skills and capabilities to achieve its business goals. It is made up of the workforce capability, employment relations, HR operations and organisational development, safety and health and administrative services branches.

Table 4-4 – Business support costs, human resources ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Human Resources ($ M)	15.60	15.14	17.67	20.58	20.99	21.23

4.2.2 Strategy and corporate affairs

Strategy and Corporate Affairs enables Western Power's internal and external communications including staff, government, media and stakeholder liaison, and community partnerships; Western Power's strategy planning process; and leads the pricing and economic regulatory management process. It is made up of the regulation, pricing and access development, strategy, corporate affairs, media management. Also included is the budget for the newly established Enterprise Solutions Partners (ESP) division, which provides the focus, expertise and resources to successfully deliver key organisation-wide strategic initiatives.

Table 4-5 – Business support costs, strategy & corporate affairs ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Strategy & corporate affairs ($M)	12.43	12.27	17.18	23.12	23.34	23.58

Of note is that within this division, there is a centrally managed strategic initiative fund included annually from 2008/09, valued at $5.0M per year.

4.2.3 Finance

The objective of the Finance Division is to deliver the finance and administrative services to enable achievement at the Business Unit's planned business performance. It is made up of the Business Analysis, Corporate Accounting and Tax, Treasury and Risk branches.

Table 4-6 – Business support costs, finance ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Finance ($M)	10.63	12.00	14.20	15.85	16.18	16.44

4.2.4 Legal and governance

The Legal & Governance team provides advice and support to Western Power's directors, senior management and all other areas of the corporation

Table 4-7 – Business support costs, legal and governance ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Legal and governance ($M)	3.01	4.11	6.48	7.17	7.27	7.35

4.2.5 CEO

The overall business support cost includes an amount for Western Power's CEO. Table 4-8 shows the escalated costs only relative to current regulatory period approved spend levels.

Table 4-8 – Business support costs, CEO ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
CEO ($M)	1.07	3.19	2.44	1.20	1.23	1.26

4.2.6 Insurance

Key increase in insurance expenditure is in the Public Liability and Fire and Peril categories. Table 4-9 shows the forecast expenditure on insurance, including $5.5M of self insurance costs annually.

Table 4-9 – Business support costs, insurance ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Insurance ($M)	12.94	15.00	16.17	17.28	18.01	18.83

4.2.7 Rates and taxes

The increase in rates and taxes in 2008/09 is driven by land tax (forecast to increase to $5.5m). Increases in 2009/10 through to 2011/12 are based on advice received by the Environmental Land Management branch within Western Power from Landgate, the Western Australian Land Information Authority on 18th June 2008.

Table 4-10 – Business support costs, rates and taxes ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Rates and Taxes ($M)	4.77	5.51	6.68	7.50	8.40	9.41

4.2.8 Energy Safety Levy

Forecast for this line of expenditure is per the Energy Safety Levy notice 2008, published in the Government Gazette on April 29th 2008, escalated.

Table 4-11 – Business support costs, Energy Safety Levy ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Energy Safety Levy ($M)	3.05	3.63	3.85	3.96	3.93	3.92

4.2.9 Design and estimating

These are the operating costs associated with the preliminary engineering and design costs that are incurred for work that does not proceed to construction. This is primarily due to customer work that does not proceed beyond the quote phase.

Table 4-12 – Business support costs, design and estimating ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Design and estimating ($M)	0	4.02	4.10	4.20	4.29	4.39

4.2.10 Fringe Benefits Tax (FBT)

An amount for fringe benefit tax is shown in Table 4-13.

Table 4-13 – Business support costs, Fringe Benefits Tax ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Fringe Benefits Tax ($M)	1.50	0.76	1.00	1.04	1.03	1.03

4.2.11 Call centre

The Customer Assist branch within the Customer Services division is currently establishing an in-house call centre that will function as a central 'gateway' for Western Power in the form of an integrated Customer Service Centre. For the first regulatory period, this function was outsourced, managed by Synergy's call centre.

Table 4-14 – Business support costs, call centre ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Call centre ($M)	5.26	5.12	6.40	5.37	5.47	5.55

4.2.12 Extended Outage Payments (EOPS)

Under the State Government's Power Outage Payment Scheme, customers affected by power interruptions lasting 12 continuous hours or longer may be eligible for an $80 payment. This is an allowance for these payments, based on historical averages.

Table 4-15 – Business support costs, Extended Outage Payments ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
EOPS ($M)	0.48	0.34	0.37	2.08	2.07	2.06

4.3 Capex

Business support capital expenditure relates to the expenditure needed for the upkeep of business offices and depots. During the next regulatory period, Western Power plans to refurbish its premises to comply with health and safety and make better use of the available office space, by using more ergonomic designs and open plan layouts. The expenditure also covers the information technology initiatives needed to ensure Western Power's various business information platforms and support applications are capable of accommodating the needs of the continuously evolving business environment.

4.3.1 Support

The support capital budget includes expenditure requirements for capital items to support and maintain office and depot accommodation. Budget items include tools and equipment required for construction, commissioning and maintenance functions and labour costs for the management or the capital works processes and programs.

Also included in this budget are the costs relating to Project Vista. Project Vista covers the refurbishment of the Perth head office and metropolitan depots. The catalyst for this project was the need to remove asbestos in the ceiling space of nine floors in the west building of the Perth office. In order to remove this asbestos each floor will be stripped bare, providing a blank canvas against which a more effective and appealing working environment that is consistent with an employer of choice will be created.

Figure 4.2 Business support costs, support Capex ($M)

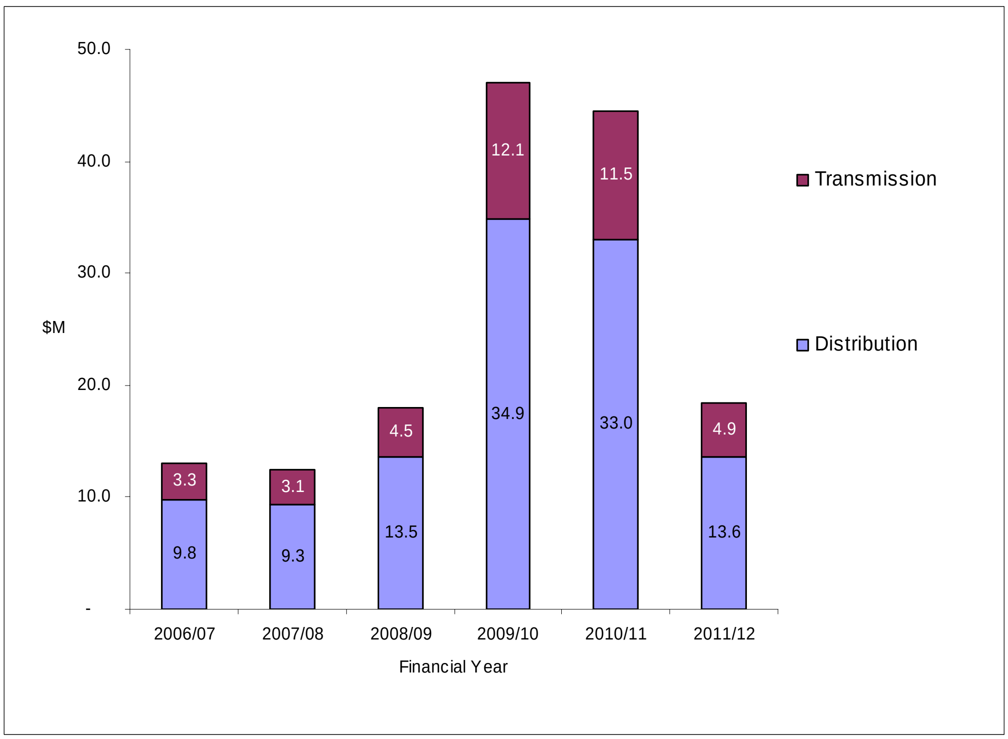


Table 4-16 – Business support costs, support Capex ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Distribution ($M)	9.77	9.35	13.53	34.91	33.00	13.59
Transmission ($M)	3.26	3.12	4.51	12.05	11.53	4.86

4.3.2 Information technology

The forecast IT expenditure include all information technology capital projects, including Strategic Programs of Work **(SPoW)**, but excluding SCADA, and all capital purchases for Printers, Blackberry's, software etc.

Western Power is embarking upon a series of business transformation programs to meet the needs of energy market reform and enable achievement of internal business improvement targets. The Strategic Program of Work (SPoW) is one of several major business change programs enabling this transformation. The SPoW is being delivered as an integrated program that will review and change many of Western Power's core business processes and replace several customised core legacy systems, with contemporary industry standard packaged solutions. The program represents a significant investment in modernising both Western Power's business practices and its supporting IT capability.

The SPoW program was developed as an integrated program in response to a growing recognition that Western Power needs to optimise its processes and provide better information for decision-making.

Figure 4.3 Business support costs, IT Capex ($M)

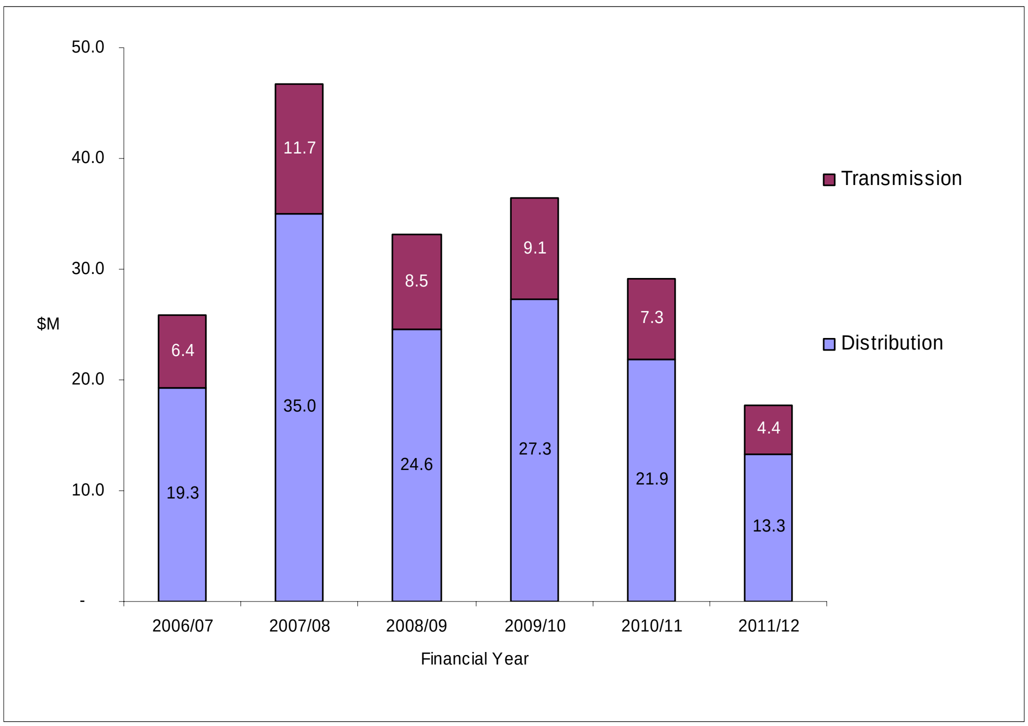


Table 4-17 – Business support costs, IT Capex ($M)

	06/07	07/08	08/09	09/10	10/11	11/12
Distribution ($M)	19.35	34.99	24.58	27.30	21.90	13.34
Transmission ($M)	6.45	11.66	8.53	9.10	7.30	4.45

5 Transmission Forecast Capital Expenditure

In this section, Western Power sets out its forecast transmission Capex over the 2009/10 to 2011/12 three year regulatory period. The expenditures for each activity type are presented; the reasons for changes in expenditure levels from previous years are discussed, as well as the major drivers in each category; and an overview is provided of the most significant projects.

5.1 Overview

At a high level, Western Power is proposing to invest $2.19B during the next three year regulatory period on its transmission asset base. The historical and projected Capex associated with Western Power's transmission network assets are summarised in Figure 5-1 and Table 5-1. It can be seen from Figure 5-1 that it is proposed to materially increase the transmission network Capex from an average of $356M per annum between the 2006/07-2008/09 period to an average of $731M per annum over the 2009/10-2011/12 regulatory period. This represents a real increase of approximately 105%, primarily associated with increases in capacity expansion expenditure.

The increase in transmission network Capex can be directly attributed to one key substation development in the Perth CBD area, and six major transmission line projects. These projects all exceed $40M, and the line projects are as follows:

- the new Pinjar to Geraldton 330kV line
- the Grange Resources mine 220kV supply
- the Shotts Well to Eastern Terminal 330kV line
- the new Kojonup-Albany 132kV line
- the new Gindalbe Metals-Eneabba-Three Springs 330kV line
- the new Wanneroo-Hocking-Wangara 132kV line.

Figure 5-1 –Transmission capital expenditure

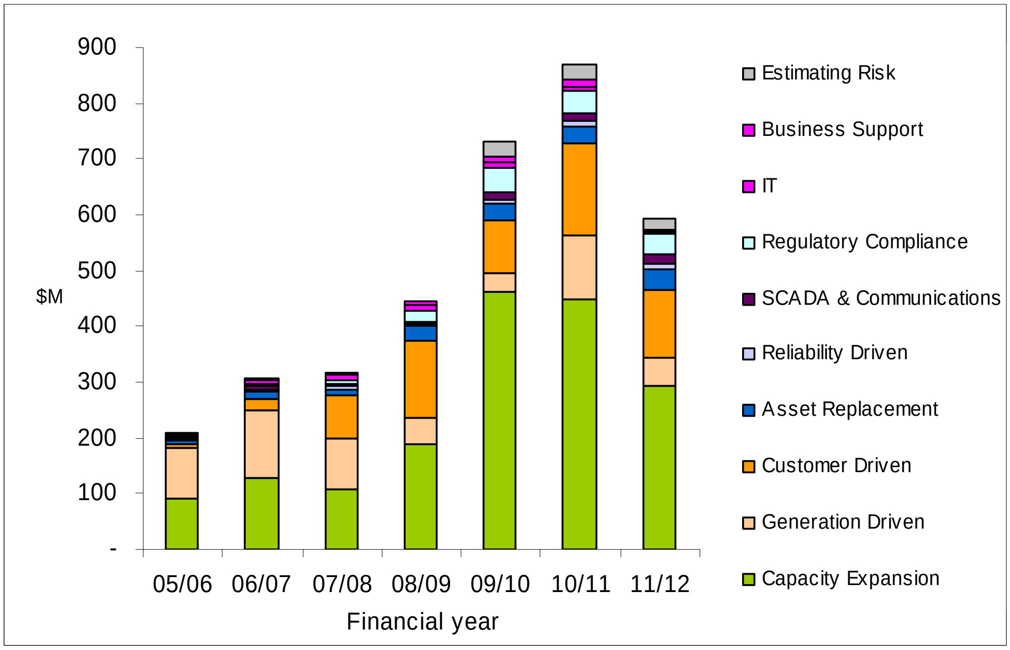


Table 5-1 – Transmission capital expenditure

Expenditure category	05/06	06/07	07/08	08/09	09/10	10/11	11/12
GROWTH							
Capacity expansion	89.97	127.43	109.16	188.26	460.26	449.16	292.98
Generation driven	90.52	121.29	90.73	47.80	36.43	112.49	49.52
Customer driven	8.70	19.26	75.59	139.53	92.56	165.18	121.42
Estimating Risk (3.5%)	0	0	0	0	20.62	25.44	16.24
ASSET REPLACEMENT & RENEWAL							
Asset replacement	7.70	13.88	11.74	26.79	30.58	30.95	38.61
Estimating Risk (3.5%)	0	0	0	0	1.07	1.08	1.35
IMPROVEMENT IN SERVICE							
Reliability driven	1.21	5.17	5.25	2.01	6.14	9.64	9.25
SCADA & communications	4.55	5.92	3.91	4.74	13.04	13.39	15.83
Estimating Risk (3.5%)	0	0	0	0	0.67	0.81	0.88
COMPLIANCE							
Regulatory compliance	3.77	4.20	5.87	18.97	45.86	41.45	37.11
Estimating Risk (3.5%)	0	0	0	0	1.61	1.45	1.30
CORPORATE							
IT	0.85	6.45	11.66	8.52	9.10	7.30	4.45
Business support	3.12	3.26	3.09	7.01	12.05	11.53	4.86
Total ($M)	**210.39**	**306.86**	**316.98**	**443.63**	**729.98**	**869.86**	**593.79**

5.2 Current regulatory period – capital work in progress

In this section we set out the forecast capital expenditure initiated[38] by changing system and customer needs approved through the Works Program change control and governance process in the current regulatory period that will continue into the next regulatory period. The principal reasons for the significant volume of work extending into the new regulatory period are presented. An overview of the most significant projects extending into the new regulatory period is also provided.

Projects that have been initiated under Western Power's first Access Arrangement are not discussed in detail in this report. Western Power notes that the ERA is being separately advised of those projects that are classed as 'major augmentations' under the Access Code.

Figure 5-2 and Table 5-2 show the transmission capital expenditures required in the next regulatory period for work-in-progress by financial year and regulatory category. The regulatory categories accounting for the majority of transmission capital expenditure work in progress are Capacity Expansion, Generator Driven, and Customer Driven.

Figure 5-2 –Transmission capital expenditure – work in progress

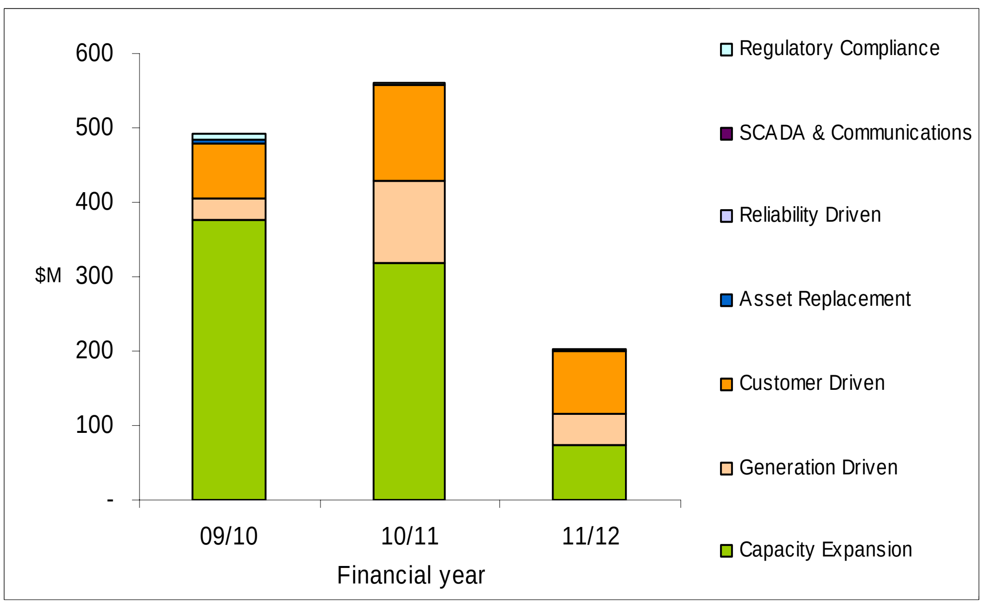


Table 5-2 – Transmission capital expenditure[39] – work in progress

Expenditure category	09/10	10/11	11/12
GROWTH			
Capacity expansion	375.73	317.86	74.49
Generation driven	30.11	111.23	42.11

[38] Initiated in this case means the project has been Board approved and work has commenced.

[39] Excludes estimating risk expenditure component

Customer driven	74.16	129.15	83.31
REPLACEMENT & RENEWAL			
Asset replacement	3.41	0.06	0
IMPROVEMENT IN SERVICE			
Reliability driven	0.14	0	0
SCADA & communications	0.47	0.09	0.17
COMPLIANCE			
Regulatory compliance	8.13	2.57	1.86
Total ($M)	**492.15**	**560.96**	**201.94**

5.2.1 Principal projects – transmission Capex – works in progress

The principal projects (>$100M) included in transmission capital expenditure work in progress are outlined below.

330kV transmission line and associated works - North Country region (capacity expansion)

The North Country region transmission network is connected to the rest of the SWIS via very long 132kV transmission lines. Peak demand in the North Country region has grown extremely rapidly over the last 12 months to the extent that it is approaching the power transfer limit. The load forecast shows the supply capacity of 155MW will be exceeded by peak demand in the summer of 2009/10; this only considers load growth from the existing customers and approved new customers.

In addition, the North Country network is not capable of supporting the large number of prospective industrial customers, comprising about 200MW of mining and industrial load, 860MW of wind generators and 600MW of gas and coal generation, who wish to connect to the network.

The proposed solution involves:

- establishing a new 330/132kV terminal substation at Moonyoonooka
- constructing a new Pinjar-Moonyoonooka 330kV double-circuit line
- installing line circuits at Neerabup Terminal
- associated distribution work.

Initially, one side of the proposed new line will be energized at 330kV and the other will operate at 132kV. Moonyoonooka Terminal will comprise only a single transformer to minimize the up-front investment. This initial work will deliver more than 400MW of transfer capacity. The double-circuit 330kV configuration should provide sufficient transfer capacity in the North Country region for the next 20 years, when it is fully developed. The target date for completion is November 2010.

Table 5-3 – 330kV transmission line and associated works - North Country region (T0180069) – work in progress

Project	09/10	10/11	11/12
330kV Trans Line – North Country	253.13	94.89	12.84

Strengthen transmission links to Albany (capacity expansion)

The electricity demand forecast for the Lower Great Southern Region predicts that load will more than quadruple by 2012, from less than 50MVA to 200MVA, possibly exceeding this level within the next 20 years.

Supply links into existing substations need to be significantly strengthened; additional load will be supplied from new substations at Mirambeena and Southdown and a second Albany substation. Around 50% of the load growth results from the as yet unconfirmed development of the Southdown iron–ore mine by Grange Resources near Wellstead.

Preliminary studies, incorporating the Southdown development, support the construction of a single circuit 220kV transmission line from Muja to Kojonup, a separate single circuit 220kV line supply to Southdown (for the Grange Resources project below) and the strengthening of supply to Albany through a double circuit 132kV line.

Western Power has engaged independent expert advisors[40] to assist with the identification of the best network reinforcement options and to consider generation and demand side solutions to meet the projected load growth. The preferred option will be subject to the New Facilities Investment Test. It is intended to submit the project for approval to the Economic Regulating Authority (ERA) by the middle of 2008 and shortly afterwards by Western Power's Board.

Table 5-4 – Strengthen transmission links to Albany (T0003620) – work in progress

Project	09/10	10/11	11/12
Kojonup-Albamy 132kV Transmission Line	3.09	112.30	23.39

Grange resources mine 220kV supply (customer driven)

This project is associated with the project to strengthen transmission links to Albany (above). The forecast load associated with the Grange Resources mine represents a significant proportion of the total forecast load growth in the Albany region. Negotiations with Grange Resources are continuing, so project estimates and timing are provisional at this stage.

The Grange Resources project provisionally includes the following works:

- install 220kV line circuit at Muja
- construct 290km on single circuit 220kV line (Muja-Southdown)

[40] SKM Consulting (Perth)

- construct a 220kV single busbar substation with one 220kV line circuit. The busbar should allow space for two 220kV transformer circuits for the customer and two similar circuits for Western Power's future use.

Table 5-5 – Grange resources mine 220kV supply (T0195984) – work in progress

Project	09/10	10/11	11/12
Grange resources mine 220kV supply	30.03	67.59	81.67

Shotts Well to Eastern Terminal new double circuit 330kV transmission line (generation driven)

Increasing load in the metropolitan area supplied by new generation connecting to the south-west network is affecting the voltage stability of the entire bulk transmission network.

System studies indicate that by 2011 an outage of a major 330kV transmission line or transformer could result in low voltages across the 330kV network around Perth. These low voltages would initially result in widespread load shedding, and if the load shedding was not sufficient to restore voltages, voltage collapse would occur.

To ensure network stability, the 330kV supply from the southwest generation sources to the metropolitan load centre needs to be strengthened. In November 2010, this will be achieved by constructing a new 330kV double circuit transmission line from Wells Terminal to the proposed Eastern Terminal site and by establishing South-East Terminal.

Table 5-6 – Shotts Well to Eastern Terminal new double circuit 330kV transmission line (T0176821) – work in progress

Project	09/10	10/11	11/12
Shotts Well to Eastern Terminal new double circuit 330kV transmission line	8.91	106.81	42.11

5.3 Capacity Expansion Capex[41]

The Capacity Expansion (CE) expenditure category (previously referred to as System Capacity) includes all growth driven reinforcement of the transmission and sub-transmission systems, including zone substations, but excludes the work for the local connections to give customer access to the network for new generators and bulk loads. The primary driver for capacity expansion Capex is growth of the peak summer demand supplied within in the SWIS. Discussion regarding the nature of the SWIS demand growth is captured within Section 3.1 of this document – which is primarily informed through independent forecasts produced by the Independent Market Operator.

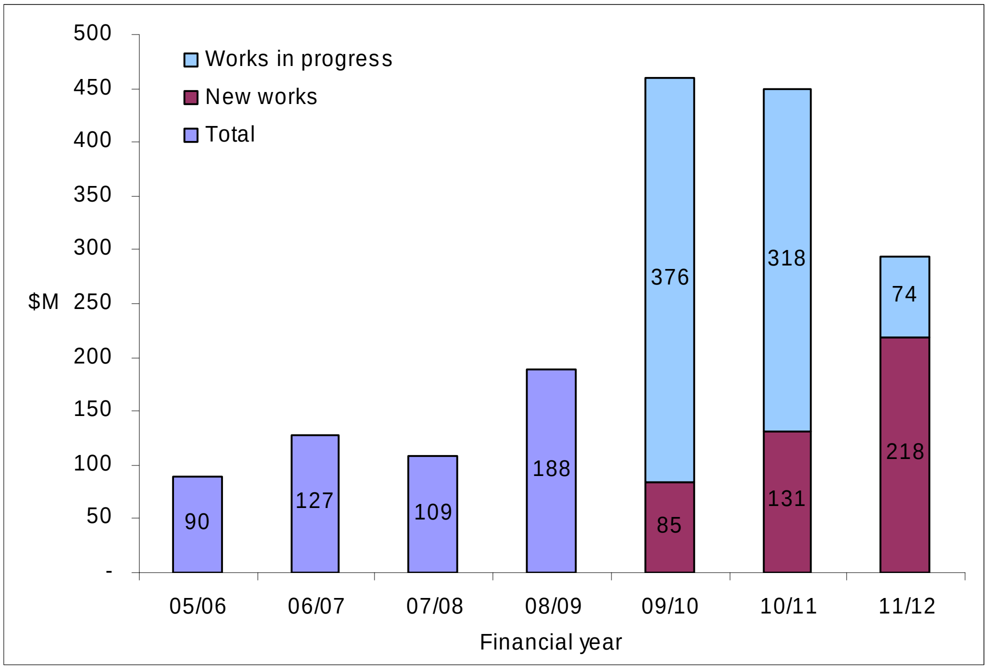
From Figure 5-3, it can be seen that over the next regulatory period Western Power proposes to increase the transmission capacity expansion Capex from an average of $147M per annum in the 2006/07 to 2008/09 period, to an average of $401M per annum over the next regulatory period. This represents a material increase of approximately 273%.

41 Excludes estimating risk expenditure component

Approximately $1,202M (58%) of Western Power's entire forecast Capex over the next regulatory period is attributed to CE, with $768M associated with work in progress and $434M associated with new works initiated in the next regulatory period.

The remainder of this section of the report is focused on the new works only.

Figure 5-3 – Transmission capacity expansion capital expenditure ($M)



Western Power proposes to initiate 80 separate transmission based CE projects in the 2009/10 to 2011/12 regulatory period. These can be divided into the following categories:

- the development of new or upgraded transmission lines (29% of Capex, 14 projects). These projects are informed through annual and systematic technical studies based on the bulk transmission network and 13 regionally based area studies focused on major load centre's and the existing network configuration
- the development of new or upgraded zone substations (59.6% of Capex, 39 projects). These projects are informed through a separate annual process that involves a highly integrated and detailed review of spatial demand forecasts (by region and substation) and the capacity of existing transformer capacity at substations
- the acquisition of land for sites and easements (11% of Capex, 21 projects), which is informed from the long term development plans
- other, which captures minor projects such as circuit breaker works, distribution driven projects and some reactive plant works (0.4% of Capex, 6 projects).

Specific details of development strategies associated with each of these sub-categories are outlined in the following sections.

The process adopted by Western Power to produce the bulk transmission system augmentation forecast is based on Western Power's normal planning cycle. This is described in the Transmission and Distribution Annual Planning Report **(APR)** which is a public document produced by Western Power[42]. This is also similar to the process followed to assess system capacity.

In this planning cycle the bulk transmission system capacity is assessed against the planning criteria, forecast peak demand growth and a generation dispatch scenario to determine forecast violations of planning criteria. This analysis is carried out via power system modelling of the bulk transmission system. Typically a wide range of options to alleviate the network violations is considered, while also giving due consideration to the condition and replacement strategies of the transmission assets.

These options are then costed, and both technical and economic evaluations are performed to determine the most prudent and efficient solution.

The analysis defining the needs, the options and the evaluation are discussed in the Bulk Transmission System Long Term Development Study Notes report. This report is updated each year.

Separate project data sheets are produced for each project that builds the shared network forecast. These sheets provide an overview of network issues and related Western Power reports. They also summarise the main driver, planning criteria, options considered, and scope and cost of the preferred option.

5.3.1 New or upgraded transmission lines

Western Power is proposing to initiate 7 new transmission line projects and upgrade 7 existing lines, at an aggregated cost of $126M over the 2009/10 to 2011/12 regulatory period. There are four major projects with Capex in excess of $15M in this period, as outlined in Table 5-7.

Table 5-7 – Transmission capital expenditure – new/upgraded lines ($M)

Project	Region	09/10	10/11	11/12	Total
Picton-Busselton 132kV SC line (T0123179)	Bunbury	9.00	10.05	18.01	37.06
South Fremantle-Amherst St 132kV cable (T0267454)	South Fremantle	1.08	15.73	6.36	23.17
Guildford-Forrestdale 132kV line (T0249657)	Cannington	14.21	4.26	0	18.47
Rudds Gully-Moonyoonooka 132kV SC line (T0190385)	North Country	1.48	11.66	4.49	17.63
Others (x 4)	Cannington	2.16	4.34	1.88	8.38
Others (x 1)	Muja	0	0.66	8.15	8.81
Others (x 1)	Kwinana	0.25	4.15	1.66	6.06
Others (x 2)	Northern Terminal	0.38	0.31	4.68	5.37
Others (x 2)	Bunbury	0.11	0.44	0.87	1.42
Total ($M)		**28.67**	**51.6**	**46.1**	**126.37**

42 Available on Western Power's public website www.westernpower.com.au

Western Power provides the following high level overview of the two most expensive transmission line projects proposed. The remaining projects have been assessed in a similar manner, as detailed in the relevant project template documents.

Picton-Busselton 132kV single circuit line (T0123179)

The Picton-Busselton 132kV single circuit line project is driven by a need to increase the voltage stability constrained transfer capacity from Picton to the growing areas of Busselton and Margaret River. The constraint occurs for loss of the 132kV Picton-Pinjarra/Busselton line, which results in the underlying 66kV network carrying the entire load in this area and voltages falling below the statutory limit at Busselton. The required commissioning date is November 2012 based on demand forecasts in the area increasing from around 73MVA[43] in 2007/08 to around 89MVA in 20011/12.

The proposed solution involves re-construction of the existing 66kV circuit between Picton-Capel/Westralian Sands and Capel-Busselton to 132kV, with the new line bypassing Capel to form one circuit directly between Picton and Busselton. Appropriate 132kV switching augmentation at each of these two substations is also necessary. Western Power has considered distribution load transfer, reactive support (including dynamic and static devices), construction of a new line while maintaining the existing 66kV circuit, and utilisation of local generation as alternatives. However none of these is considered technically and economically feasible compared with the preferred and recommended solution.

South Fremantle-Amherst St 132kV cable (T0267454)

The South Fremantle-Amherst St 132kV cable project is driven by a need to increase the thermal transfer capacity between the existing substation sites for outage of two (N-2) of the existing connected 132kV circuits. The N-2 criteria are only applied at demand levels of 80% of the peak summer demand forecasts. The required commissioning date is November 2011.

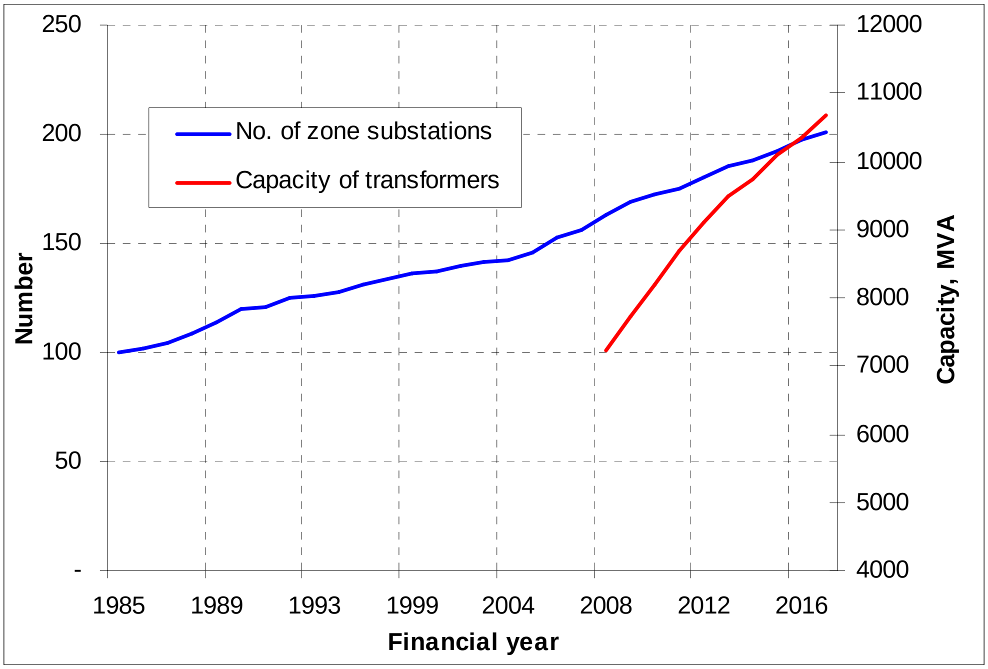
The proposed solution involves construction of a 132kV cable between South Fremantle and Amherst, and appropriate 132kV switching augmentation at each of these substations to allow for connection of the new line. Western Power has considered upgrading the existing circuits and utilisation of local generation as alternatives, however neither of these is considered technically and economically feasible compared with the recommended solution.

5.3.2 New or upgraded zone substations

Western Power is proposing to initiate 14 new substation projects and upgrade the transformation capacity at 17 existing substations, at an aggregated cost of $246M over the 2009/10 to 2011/12 regulatory period. The net impact of all of Western Power's zone substation capacity development is summarised in Figure 5-4, where it can be seen that the number of new substations has been steadily increasing over time, and that the aggregate capacity of transformation at these sites will approach 11,000MVA by 2018.

43 Westralian Sands, Busselton, Margaret River and Capel substations.

Figure 5-4 – Changes in the capacity and number of substations over time



Consistent with its approach during the 2006/07-200/09 regulatory period, Western Power's zone substation Capex is influenced by its 'NCR windback' program. During the 1990's, a Normal Cyclic Rating (NCR) policy was introduced to manage capital restrictions, which allowed certain substations to be loaded to 90% of their normal cyclic rating if a rapid response spare transformer (RRST) was available in the event of a transformer failure.

As part of ongoing reviews accounting for operational experience and wider industry practices, Western Power has reduced the NCR criteria down from 90% to 75%. The effect of this has been to increase the capital expenditure over historical levels in order to reduce substation loadings through the installation of additional transformer capacity and the establishment of new substations.

There are four major projects with Capex in excess of $19M in this period, as outlined in Table 5-8.

Table 5-8 – Transmission capital expenditure – new/upgraded substations ($M)

Project	Region	09/10	10/11	11/12	Total
New CBD substation	East Perth	4.03	31.74	9.53	45.3
New Nedlands substation	Western Terminal	0.06	2.63	27.59	30.28
New O'Conner substation	South Fremantle	6.51	1.93	18.45	26.89
New East Rockingham substation	Kwinana	1.91	13.43	4.03	19.37
Others (x 4)	Kwinana	1.01	6.33	31.38	38.72
Others (x 5)	Northern Terminal	1.69	10.16	13.00	24.85
Others (x 5)	North Country	12.85	3.64	6.16	22.65
Others (x 4)	Cannington	3.65	2.82	3.90	10.37
Others (x 2)	East Perth & CBD	2.38	0.33	7.47	10.18
Others (x 3)	Southern Terminal	0	0.93	7.13	8.06
Others (x 1)	South Fremantle	1.78	0.10	3.43	5.31
Others (x 2)	Bunbury	0	0	2.43	2.43
Others (x 1)	Western Terminal	0	0	1.70	1.70
Total ($M)		**35.87**	**74.04**	**136.2**	**246.11**

Western Power provides the following high level overview of its most expensive substation project proposed. The remaining projects have been assessed in a similar manner, as detailed in the relevant project template documents and the Summer Load Trends report for the SWIS period 2008-2027 (August 2007).

New CBD substation

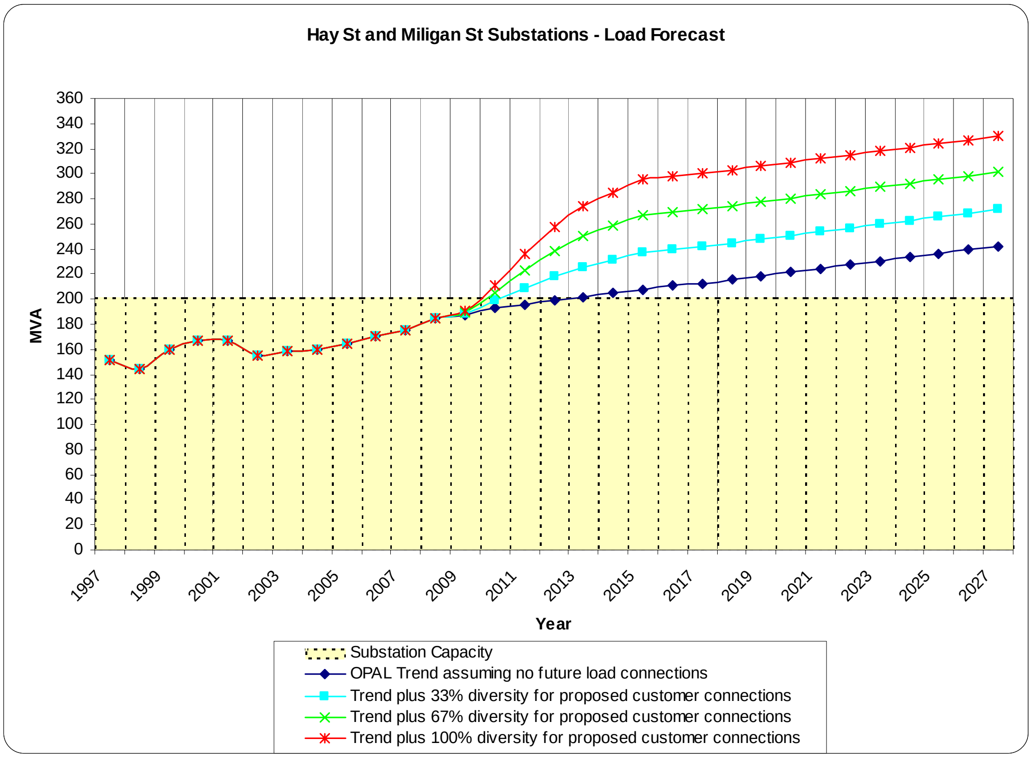
The CBD substation project is driven by two specific needs:

- a necessary increase in the number of distribution feeders available to new large customers (greater than 3MVA) in the Perth CBD area[44]. Given the double circuit radial supply arrangements into Hay and Milligan St substations, multiple distribution feeders are required from each of these key sites to back-up the other in the event of loss of both 132kV supply circuits
- a necessary increase in the 132/11kV transformer capacity in the CBD to cater for outage of both 132kV supply circuits into Hay St substation.

The required commissioning date is November 2011 based on demand forecasts in the area increasing from around 185MVA in 2007/08 to around 200MVA in 20011/12. Figure 5-5 shows the Milligan St substation capacity and the forecast flows on the critical loadings for these demand forecasts.

44 In accordance with section 2.5.4.2 and 2.5.3 of the Technical Rules, Western Power is required to augment the network so that all customers connected in the Perth CBD are provided with firm supply following the simultaneous outage of two key elements of the transmission network or the loss of any high voltage distribution element.

Figure 5-5 – Forecast demand to justify the CBD substation development



If the CBD substation augmentation does not proceed, then for the described N-2 critical contingency, there is the risk of the following amount of load being shed, dependant upon the low, medium or high diversity factor scenario.

Table 5-9 – Load at risk – need for new CBD substation

Year	Load at Risk (MVA)		
	Diversity = 0.33	Diversity = 0.66	Diversity = 1.00
2008	-	-	-
2009	-	-	-
2010	-	3.8	9.7
2011	7.9	21.4	34.5
2012	17.1	37.0	56.3
2013	24.8	49.5	73.6
2014	30.2	57.5	84.0
2015	35.7	65.5	94.4

The proposed solution involves the green-field development of a 2 x 60MVA 132/11/11kV substation at an existing site at James St. This will be supplied by cutting into the Cook St - East Perth 132kV circuit. Appropriate 132kV switching augmentation at each of these two substations is also necessary. Western Power has considered development of a similar substation at Murray St and demand side management as alternatives, however none of these is considered technically and economically feasible compared with the preferred and recommended solution.

5.3.3 Land acquisition for sites and easements

For the purposes of Capacity Expansion projects, Western Power is proposing to acquire 20 parcels of land for either new substation sites or line easements, at an aggregated cost of $46M over the 2009/10-2011/12 regulatory period. There are two major investments with Capex in excess of $12M in this period, as outlined in Table 5-10.

Table 5-10 – Transmission capital expenditure – sites and easements ($M)

Project	Region	09/10	10/11	11/12	Total
Wilson sub site purchase	Cannington	0.00	0.47	14.32	14.79
Karrinyup sub site purchase	Northern terminal	12.34	0.00	0.00	12.34
Others (x 7)	Bunbury	1.35	1.10	6.13	8.58
Others (x 1)	East Perth and CBD	0.00	0.00	5.26	5.26
Others (x 3)	Northern terminal	1.14	0.80	1.43	3.37
Others (x 3)	Kwinana	0.40	0.00	1.16	1.56
Others (x 3)	North country	0.18	0.01	0.00	0.18
Others (x 1)	East Country	0.00	0.03	0.09	0.12
Others (x1)	General	0.07	0.08	0.06	0.21
Total ($M)		**15.48**	**2.49**	**28.45**	**46.42**

Typically, Western Power pre-emptively acquires land for the purposes of terminal station and substation sites, as well as easements for new transmission lines and feeders approximately ten years prior to their application. This may vary depending on the strategic nature of the site and the anticipated complications associated with particular acquisitions.

In the case of the Karrinyup site, the substation development is expected to occur in 2017/18, and the site acquisition is planned for six years in advance in 2011/12. The Wilson substation development is anticipated in 2017/18, with its site acquisition occurring eight years in advance in 2009/10.

5.3.4 Other Capacity Expansion projects

Western Power is proposing to initiate 15 miscellaneous capacity expansion projects aimed at specific augmentation identified through the annual planning cycle, at an aggregated cost of $15.5M over the 2009/10 to 2011/12 regulatory period. There are two major projects with Capex in excess of $1.8M in this period, as outlined in Table 5-11.

Table 5-11 – Transmission capital expenditure – other CE projects ($M)

Project	Region	09/10	10/11	11/12	Total
Decommission Victoria Park – stage 1	Cannington	1.05	1.18	6.09	8.32
Bunbury Harbour 22kV busbar	Bunbury	1.88	0	0	1.88
Others (x 1)	Cannington	0.16	0.71	0.54	1.41
Others (x 4)	East Perth & CBD	0.71	0.40	0.06	1.17
Others (x 1)	Sothern Terminal	0	0.04	0.95	0.99
Others (x 2)	East Country	0.12	0.53	0.16	0.81
Others (x 1)	Muja	0.13	0.33	0	0.46
Others (x 2)	Northern Terminal	0.24	0.03	0	0.27
Others (x 2)	South Fremantle	0.23	0	0	0.23
Total ($M)		**4.52**	**3.22**	**7.8**	**15.54**

Western Power provides the following high level overview of the two most expensive projects proposed. The remaining projects have been assessed in a similar manner, as detailed in the relevant project templates. Amongst other things they include investment to cater for distribution driven projects, installing additional feeder exits, new shunt capacitor banks, and replacing circuit breakers to allow for increased fault currents.

Decommissioning Victoria Park 66/6.6kV – Stage 1

The need for this project is linked to the requirement to support load growth in Welshpool area. Following a fire at Victoria Park in 2001, most of the substations load has already been transferred from the 6.6kV network to 22kV and transferred to Tate Street substation. The remaining 6MVA forecast load will be converted to 22kV over the next 5 years to allow the existing site to be utilised for a new 132/22kV substation, timed for completion in December 2013.

The scope of work captured in the 2009/10-2011/12 regulatory period pertains to re-arranging the 66kV supplies to bypass the substation and removal of all 66kV switchgear, including the transformers.

Bunbury Harbour 22kV busbar augmentation

This work is driven by the need to balance the flows on the three existing 132/22kV transformers in order to optimize the overall transfer capacity. The scope of work includes the installation of a new indoor 22kV switchboard, that will increase the number of feeder exists and allow for flexibility in load balancing. Should the augmentation not proceed, the unbalance would result in firm capacity being exceeded under summer 2009/10 peak demand condition, thereby necessitating the work prior to the summer period.

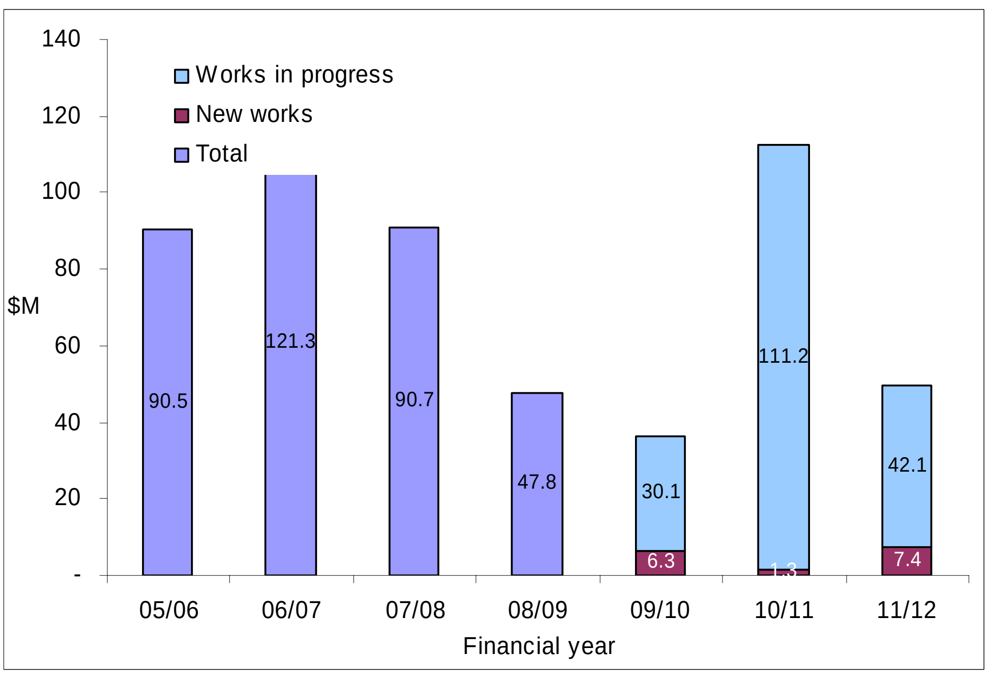
5.4 Generator Driven Capex[45]

The Capex in the Generator Driven (GD) category includes that required for the connection of new generation to the system. This includes the upgrades and augmentations necessary to move power from the generation point to the load centre under the most feasible dispatch scenarios and the cost of connecting the generation to the system. It excludes the costs of assets (often dedicated) at the connection point for generation access (GA) to the network which is either partially or fully funded by the proponents, and which is presented in the Customer Driven category.

The primary drivers of expenditure in this category predominantly relate to the power station development assumptions over the outlook period, as discussed in further detail in section 3.2.

In accordance with Figure 5-6, it can be seen that over the next regulatory period, it is proposed to materially decrease the generation driven Capex from an average of $123M per annum in the 2006/07 to 2008/09 period, to an average of $66M per annum over the next regulatory period. This represents a decrease of approximately 48%. Approximately $197M (9.6%) of Western Power's entire forecast Capex over the next regulatory period is attributed to GD, with $182M associated with work in progress and $15M associated with new works initiated in the 2009/10 to 20011/12 regulatory period. The remainder of this section of the report is focused on the new works only.

Figure 5-6 – Transmission generation driven capital expenditure ($M)



There are six discrete transmission based GD projects initiated over the 2009/10 period, as outlined in Table 5-12.

45 Excludes estimating risk expenditure component

Table 5-12 – Transmission capital expenditure – GD projects ($M)

Project	09/10	10/11	11/12	Total
Limiting reactors at Northern Terminal	4.44	0.99	0	5.43
Champion Lakes 330kV terminal station site acquisition	0	0	3.71	3.71
Wandi 330kV terminal station site acquisition	0	0	3.71	3.71
Shunt capacitor at Southern Terminal	1.19	0.27	0	1.46
Shunt capacitors in CBD area	0.40	0	0	0.40
Shunt capacitors in metropolitan area	0.28	0	0	0.28
Total ($M)	**6.31**	**1.26**	**7.42**	**14.99**

The limiting reactors to be installed at Northern Terminal are associated with a need to reduce the 132kV fault levels to within plant design limits of 40kA once additional generation is connected at Neerabup in 2010/11.

The Wandi and Champion Lakes terminal station sites are located in strategic locations that would allow numerous 330kV circuits to be switched, improving the load balancing on the backbone of the SWIS transmission network. They are expected to be developed by 2019/20.

The various shunt capacitor bank installations are associated with increasing load in the metropolitan area supplied by new generation connecting to the south-west network, which is affecting the voltage stability of the entire bulk transmission network. The increased load and generation has two effects that impact on network security:

- the loading of the 330kV bulk transmission lines increases beyond their surge impedance loading, particularly after outage of a critical circuit
- the increased remote generation displaces metropolitan based generation that is the normal source of dynamic reactive power used to support the network.

5.5 Customer Driven Capex[46]

The Capex in the Customer Driven (CD) category includes that required for the access of new generation to the system, which is related to work required to maintain compliance with network planning criteria, and to meet load growth needs caused by discrete customer loads (Block Loads). This category includes projects that are either partly or fully funded by the customer. It generally includes assets (often dedicated) installed at the connection point to the network.

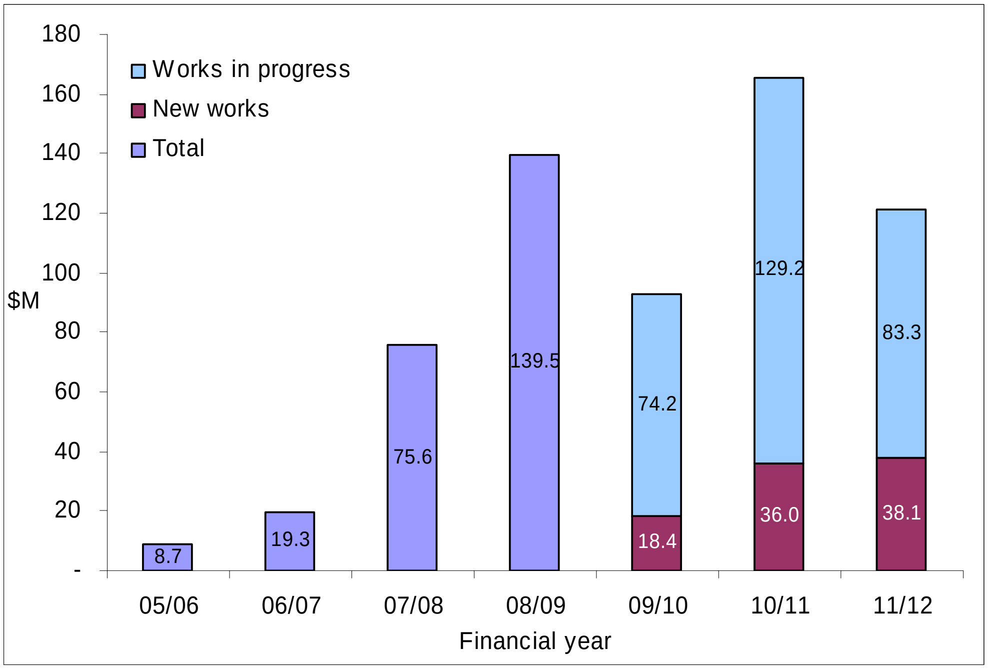
The primary drivers of expenditure in this category are related to the power station development assumptions over the outlook period, as discussed in further detail in section 3.2, and customer initiated connections over the outlook period.

In accordance with Figure 5-7, it can be seen that over the next regulatory period, it is proposed to invest in customer driven Capex of around $379M, which is approximately

[46] Excludes estimating risk expenditure component

18.3% of Western Power's entire forecast Capex over the next regulatory period. Of this amount, $287M is associated with work in progress and $92M is associated with new works initiated in the 2009/10 to 20011/12 regulatory period. The balance of this section of the report is focused on the new works only.

Figure 5-7 – Transmission customer driven capital expenditure ($M)



There are eleven discrete transmission based CD projects initiated over the 2009/10 period, as outlined in Table 5-13. Four are for bulk loads and six are for new power stations.

Table 5-13 – Transmission capital expenditure – CD projects ($M)

Project	09/10	10/11	11/12	Total
Establish Lukin substation	4.25	14.24	7.13	25.62
Establish Oakajee substation	0.14	1.69	19.08	20.91
Transmission Line Relocations	4.40	4.41	4.54	13.35
Fiona Stanley Hospital Supply (14MVA)	0	3.10	5.50	8.6
Establish UWA substation	3.87	3.09	1.85	8.81
Wind-farm extension (x 4)	3.30	8.07	0	11.37
Biomass PS	0.85	1.42	0	2.27
GT Network Connection	1.58	0	0	1.58
Total ($m)	**18.39**	**36.02**	**38.1**	**92.51**

The above forecast is based upon enquiries made to Western Power for bulk load connections with a high probability of proceeding. The main projects include:

- a new 132/22kV substation at Lukin

- a new 132/33kV substation at Oakajee, located in the North Country region, to facilitate a port development and an industrial estate, with an anticipated connection date of November 2012 and a forecast maximum demand of 20MVA in 2012/13 increasing to 40MVA by 2019/20
- a new 66/11kV substation at UWA
- a new 132/22kV substation for the Fiona Stanley Hospital development, located in the Southern Terminal region, with a forecast maximum demand of 14MVA.

5.6 Asset Replacement Capex [47]

The capital expenditure in the Asset Replacement (AR) category relates to the replacement of existing assets with a modern equivalent asset[48]. The primary drivers of expenditure in this category are related to the condition and performance of assets and the risks of plant failing in service, sometimes explosively and sometimes causing interruption to supply. The replacement triggers typically include age, condition and risk (which describes the likelihood of a plant failure occurring and the consequences of the event) that captures impacts on areas such as safety, reliability, the environment, financial costs and operational issues.

In accordance with Figure 5-8, it can be seen that over the next regulatory period, it is proposed to increase the asset replacement Capex from an average of $17M per annum in the 2006/07 to 2008/09 period, to an average of $33M per annum over the next regulatory period. This represents an increase of approximately 94%. Approximately $100M (5%) of Western Power's entire forecast Capex over the next regulatory period is attributed to AR, with $3m associated with work in progress and $97M associated with new works initiated in the 2009/10 to 20011/12 regulatory period. The remainder of this section of the report is focused on the new works only.

In order to better monitor and record transmission asset information and condition, Western Power maintains a Transmission Investment Planning Database **(TIPD)**. This database holds information on every transmission asset in the SWIS and has been used as a key tool when forecasting AR capital expenditure. As of January 2008, the TIPD primary plant database covered approximately 21,000 units at 157 substations, as well as 47km of underground cables and 7,300km of overhead lines supported by 44,500 structures. The secondary plant database covered approximately 34,100 relays across various voltage levels and used for different protection applications.

The basis of the methodology Western Power has used to determine its asset replacement capital expenditure is detailed in its annually updated SWIS Transmission Network Asset Management Plan (TNAMP)[49]. All assets are assigned an expected life given the asset type and industry based knowledge of similar assets. In addition, Western Power's experience and condition monitoring information derived from its TIPD is used to prioritise the replacement of assets. By using the actual age of each piece of equipment, coupled with specific knowledge of the condition of the asset and known defects across the asset type, empirical formulae are applied to calculate the 'Remaining Life' of each asset.

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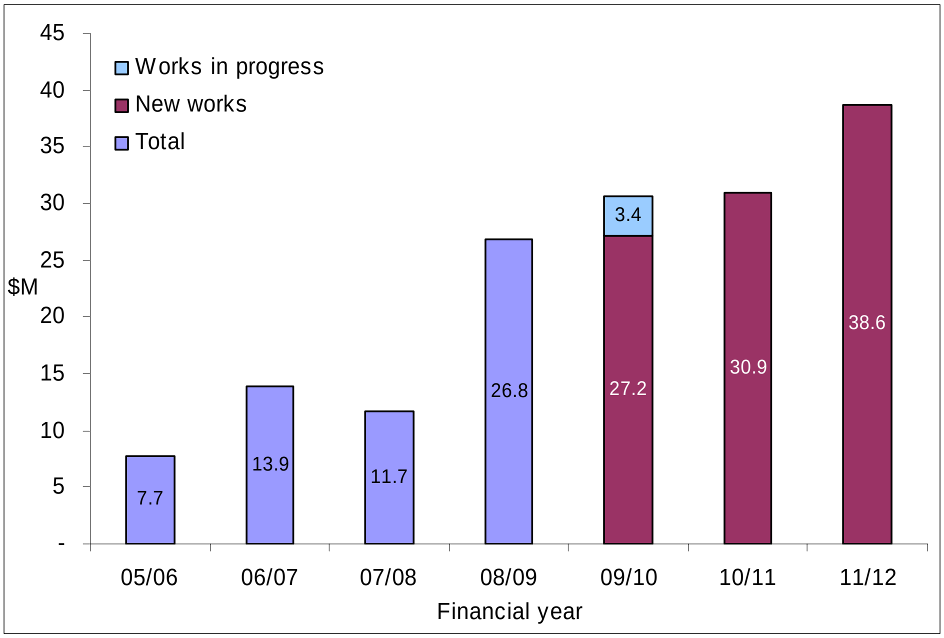
47 Excludes estimating risk expenditure component

48 Given the advanced age of the assets typically identified for replacement, the new assets are usually not a direct like-for-like replacement and provide some degree of technological improvements, often with a greater capacity and with increased monitoring facilities.

49 DMS 906804

Figure 5-8 – Transmission asset replacement capital expenditure ($M)



Western Power then undertakes a systematic analytical process, where assets with a remaining life of less then 20 years are identified and included in a long term preliminary budget for replacement. Assets with a remaining life of less than 6 years are also identified and assigned to a detailed investigation process. This can involve a number of inspections, plus tests and measurements of key parameters to determine a more appropriate condition-based remaining life. If the plant is found to be healthy and fit for service it is given a life extension and returns to the TIPD for further analysis the following year. Alternatively, the asset could:

- be reallocated for use at a less important or demanding location in the network
- be subject to a refined maintenance policy, where maintenance servicing or maintenance instructions will be varied to increase the servicing frequencies, or the scope of work during service could be completely modified
- undergo refurbishment, modification or replacement sometime in the future, and it is then added to the list of Asset Future Projects.

Within the Western Power transmission network, there are a number of factors driving the need for an increase in expenditure:

- the age profile of assets in service based on their initial installation dates. This age profile predicts a wave of asset replacement is required which would parallel the historical installation dates of major asset categories
- the condition of assets so as to ensure a safe and reliable power supply network
- the frequency and cost of maintenance
- the level of asset backlog that is overdue for replacement but remaining in service on the network due to budget and resource constraints. This backlog should be reduced taking into consideration the associated risks to the network. Further deferments will only increase the level of risk in providing a safe and reliable electric supply.

The advancing age of the network and existing condition of the assets indicates that within the next 10 to 15 years, Western Power will need to replace much greater volumes of assets than have been required to be replaced in the last ten years. Figure 5-9 shows an installation age profile for the transmission assets. This graph indicates the large number of assets that were installed around 30 years ago. Noting that transmission asset economic lives are generally in the order of 40-60 years, the graph provides a general indication that Western Power is entering a period of increasing need for asset replacement and this correlates with the increased forecast expenditure levels.

Figure 5-9 – Transmission asset age profile

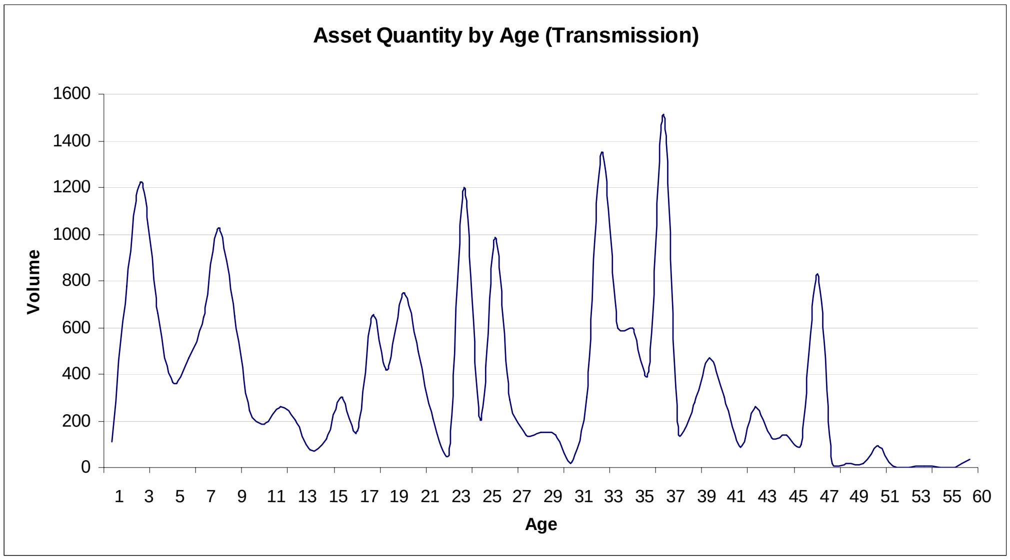
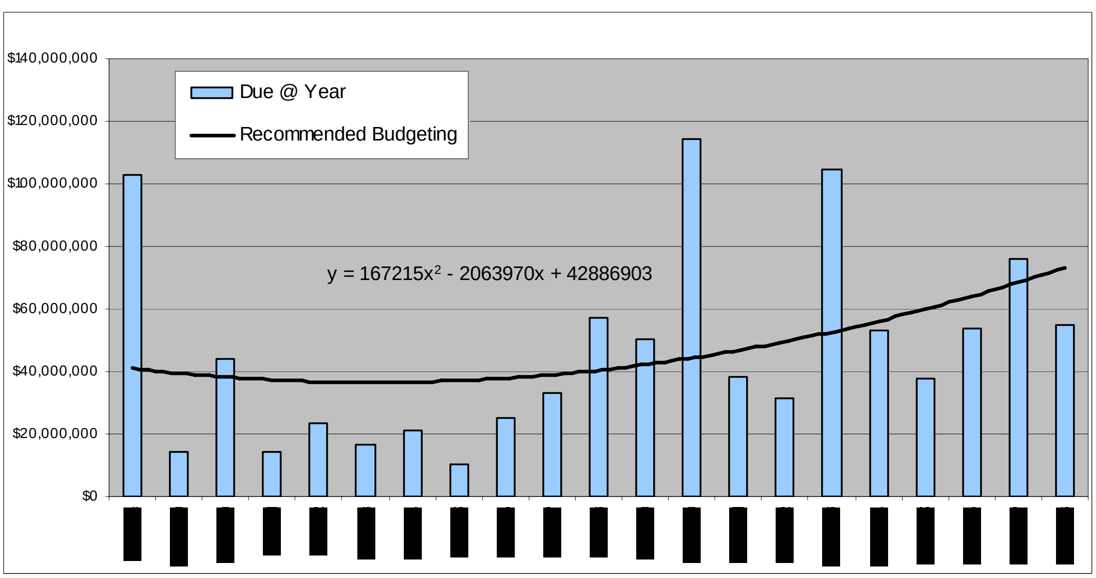


Figure 5-10 shows the 20 year asset replacement Capex forecast based upon the Western Power methodology. This graph clearly indicates the predicted rising trend in asset replacement requirements for transmission assets. The high level of expenditure in the first year indicates the level of assets that are currently considered overdue for replacement.

Figure 5-10 – Long term transmission asset replacement expenditure



Given the systematic and annual process undertaken by Western Power in determining its transmission asset replacement Capex, numerous (34) separate programs of work have been identified over the 2009/10-2011/12 regulatory period. These are summarised in Table 5-14.

Table 5-14 – Transmission capital expenditure – AR projects ($M)

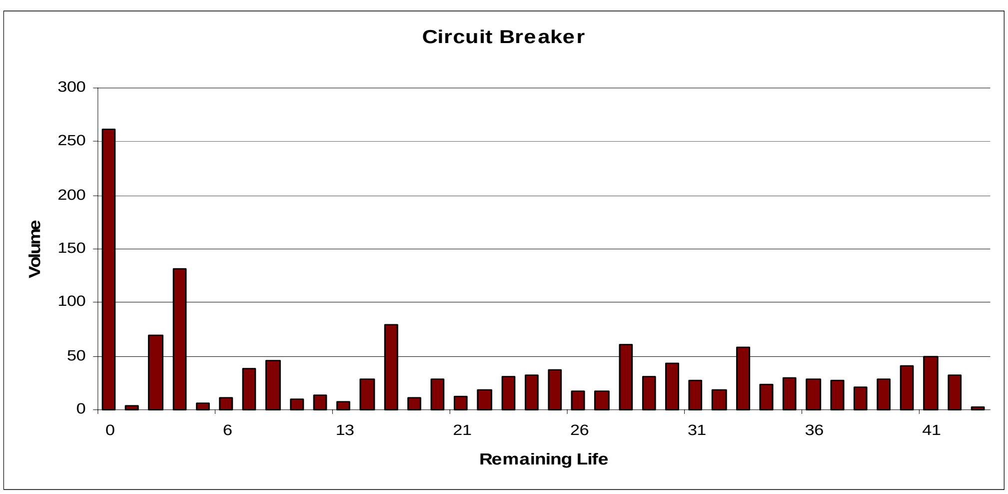
Project*	% of population	09/10	10/11	11/12	Total
Circuit breakers (549 units, 5 voltages)	9.6	4.78	9.24	11.92	25.94
Current transformers (531 units, 3 voltages)	12.6	4.69	6.05	6.34	17.08
Voltage transformers (173 units, 3 voltages)	3.2	1.39	0	3.13	4.52
Disconnectors (436 units, 2 voltages)	5.9	2.97	4.27	5.12	12.36
Transformers (11 units, at 6 sites)	3.4	3.06	3.52	4.53	11.11
Surge arrestors (139 units, 3 voltages)	8.1	3.02	1.1	0.16	4.28
Relays (45 over-current and 8 line differential)	1.3	0.67	0.87	0.40	1.94
General	-	6.62	5.85	7.00	19.47
Total ($M)		**27.2**	**30.9**	**38.6**	**96.7**

** Note: Asset volumes reflect a 5 year program with the proposed expenditure covering the 3 years of AA2.*

Western Power's circuit breakers have an expected life of 40 years and those being replaced vary in age from 26 to 53 years. Records of historical defects show that circuit breakers are the assets most prone to failure 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.

The 197 circuit breakers proposed for replacement represent 9.6% of the population and include 39 units at five locations at 11kV, 83 units at twenty-five locations at 22kV, 13 units at six locations at 33kV, 37 units at fourteen locations at 66kV and 25 units at twelve locations at 132kV in accordance with the profile of expected asset lives in Figure 5-11.

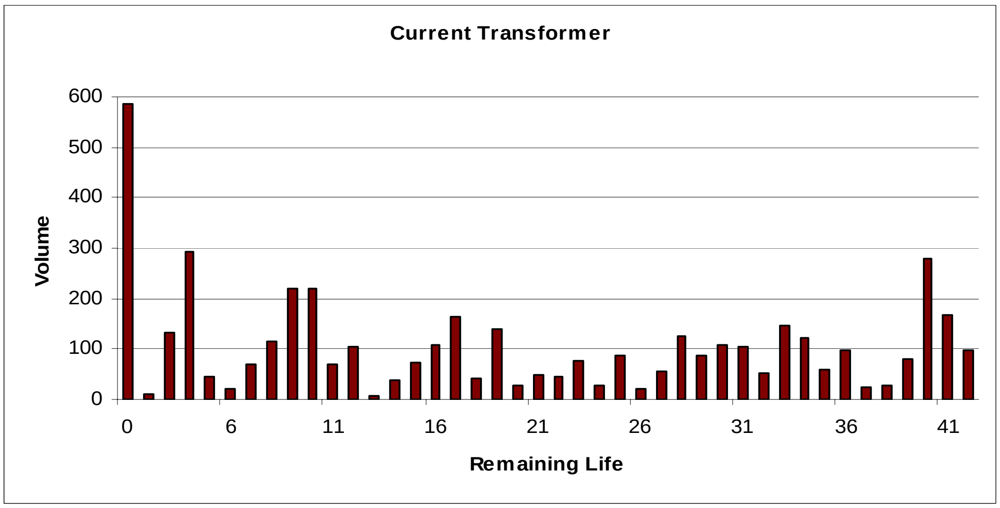
Figure 5-11 – Remaining life for transmission circuit breakers



Western Power's current transformers have an expected life of 40-45 years depending on their physical design and those being replaced vary in age from 33 to 44 years.

The 531 current transformers proposed for replacement represent 12.6% of the population and include 225 units at locations at 22kV, 139 units at seventeen locations at 66kV, and 225 units at twenty-six locations at 132kV in accordance with the profile of expected asset lives in Figure 5-12.

Figure 5-12 – Remaining life for current transformers



Western Power's power transformers have an expected life of 40-50 years depending on their physical design, size and voltage and those being replaced vary in age from 33 to 44 years. Western Power has put in place extensive condition monitoring[50] of its critical power transformer fleet. The use of on-line moisture monitors, dissolved gas analysers, and selected on-line oil monitoring equipment have all been utilised to carry out asset monitoring.

A six yearly high-voltage testing program on such equipment has also been progressed. It should be noted that the 66kV fleet has a relatively high average age and given their performance and condition are the focus of replacement investment over the 2009/10 to 2011/12 regulatory period.

The 11 power transformers proposed for replacement represent around 3.4% of the entire population located at Cannington, Collier, Merredin, Kwinana, Kalbarri and Collie, in accordance with the profile of expected asset lives in Figure 5-13.

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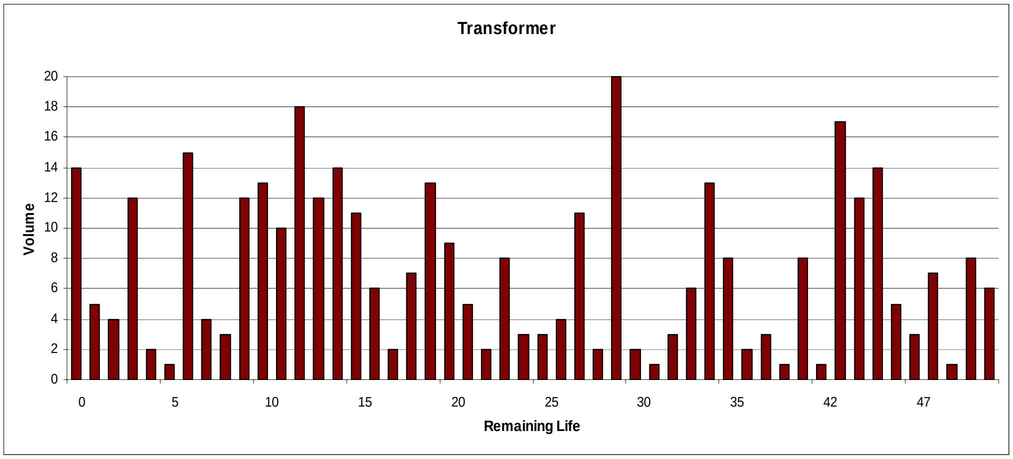
[50] DMS 4504194 – Transformer Mission Policy; Section 6

Figure 5-13 – Remaining life for power transformers



The general replacement expenditure identified covers maters such as new Vesda's fire protection systems, replacing substation batteries and chargers, replacing air conditioning and temperature monitoring within substations, plus the installation of new transformer blast walls.

5.7 Regulatory Compliance Capex[51]

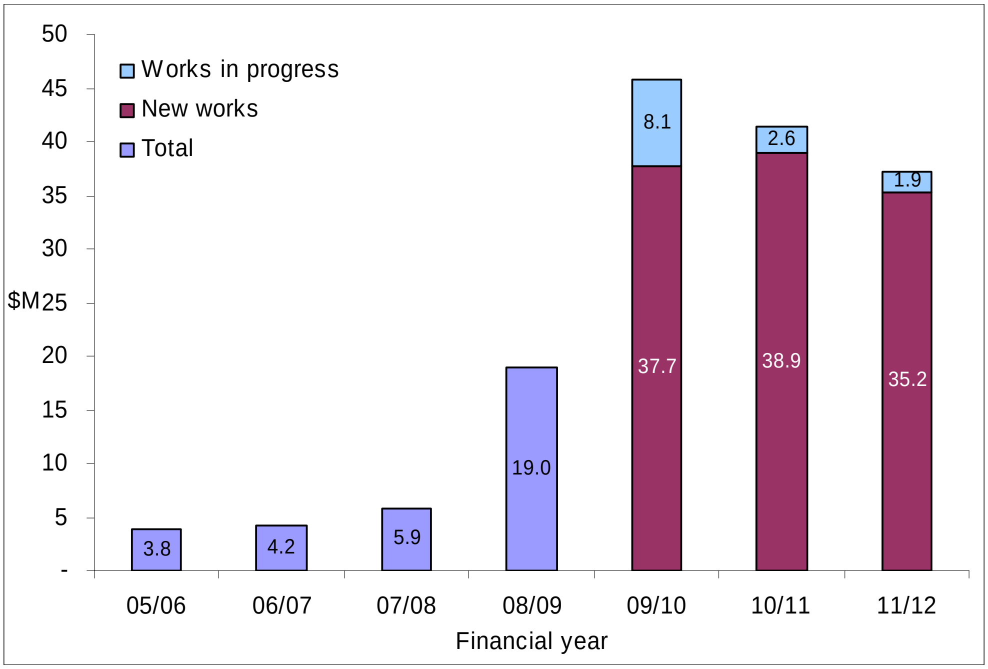
Western Power's transmission based Regulatory Compliance (RC) Capex is related to meeting external obligations including technical and safety requirements.

In accordance with Figure 5-14, it can be seen that over the next regulatory period that it is proposed to materially increase the RC/Safety/Enviro Capex from an average of $9M per annum in the 2006/07 to 2008/09 period to an average of $41M per annum over the next regulatory period.

This represents an increase of approximately 360%. Approximately $122M (6%) of Western Power's entire forecast Capex over the next regulatory period is attributed to RC/Safety/Enviro, with $12M associated with work in progress and $110M associated with new works initiated in the 2009/10 to 20011/12 regulatory period. The balance of this section of the report is focused on the new works only.

51 Excludes estimating risk expenditure component

Figure 5-14 – Transmission RC capital expenditure ($M)



There are 19 discrete transmission based RC projects proposed for initiation over the 2009/10 period, with 5 being major projects with a value exceeding $7M, as outlined in Table 5-15.

Table 5-15 – Transmission capital expenditure – RC projects ($M)

Project	09/10	10/11	11/12	Total
Transmission pole replacement	11.90	11.91	12.27	36.08
Upgrade of substation security	6.02	6.03	6.21	18.26
Removal of asbestos - priority 2 and 3	4.68	4.68	4.82	14.18
Replacement of non complying stays and insulators	4.23	4.34	4.36	12.93
Substation safety upgrade - stage 4	2.31	2.31	2.38	7.00
Other (x14)	8.56	9.63	5.16	23.35
Total ($M)	**37.7**	**38.9**	**35.2**	**111.8**

Pole replacement

The expenditure on pole replacements is necessary to replace structures that do not meet current Western Power standards and/or ENA C(b)1 requirements. Recent and current pole inspection information suggests that 750 to 800 per annum (approximately 2.5% of the population) of transmission wood poles installed between 40-60 years ago will require replacement over the next few years. This figure allows for a backlog of around 900 poles. Replacements will be prioritised based on loading versus strength ratio, by type (i.e. 'Austpole' structures), those affected by fungus, those damaged by fire, exposed to vehicle risk, and where line clearances do not meet existing standards.

Upgraded substation security

The expenditure on upgraded substation security is associated with improving the fencing and the installation of active security monitoring at about 156 existing substations owned by Western Power. This is a continuing program aimed at ensuring the ENA's 'National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure DOC 015 – 2006' are met.

Asbestos removal

Western Power has an ongoing program of work to remove all asbestos containing material from its substations. The expenditure allowance included in the 2009/10-2011/12 regulatory period accounts for sites assigned a medium and low level of risk and accounts for 60 of the 96 sites identified in the asbestos register prepared in 2005/06.

Replacement of non complying stays and insulators

In co-ordination with Energy Safety, Western Power has undertaken a review of the wet withstand flashover capability of insulators on its timber pole stays and has identified there are approximately 11,000 that do not comply with Western Power, ESAA, C(b)1 and industry standards. A Capex allowance has been included in the 2009/10 to 2011/12 regulatory period to upgrade 3,000 stays to ensure compliance with safety requirements.

Substation safety upgrades

The expenditure associated with the substation safety upgrades (Stage 4), is part of ongoing work required at operational substations to:

- reduce the risk of fatal injury
- reduce the risk of failure of equipment
- improve reliability of substation plant and overall power network system
- remove the need for costly and urgent maintenance work.

The stage 4 scope of works will address all outstanding safety issues in approximately 73 zone substations. It will include work associated with inadequate substation yard lighting, site surfacing, technical access and other safety issues so that such facilities conform to Australian Standard (AS 2067) and Western Power standards.

Other

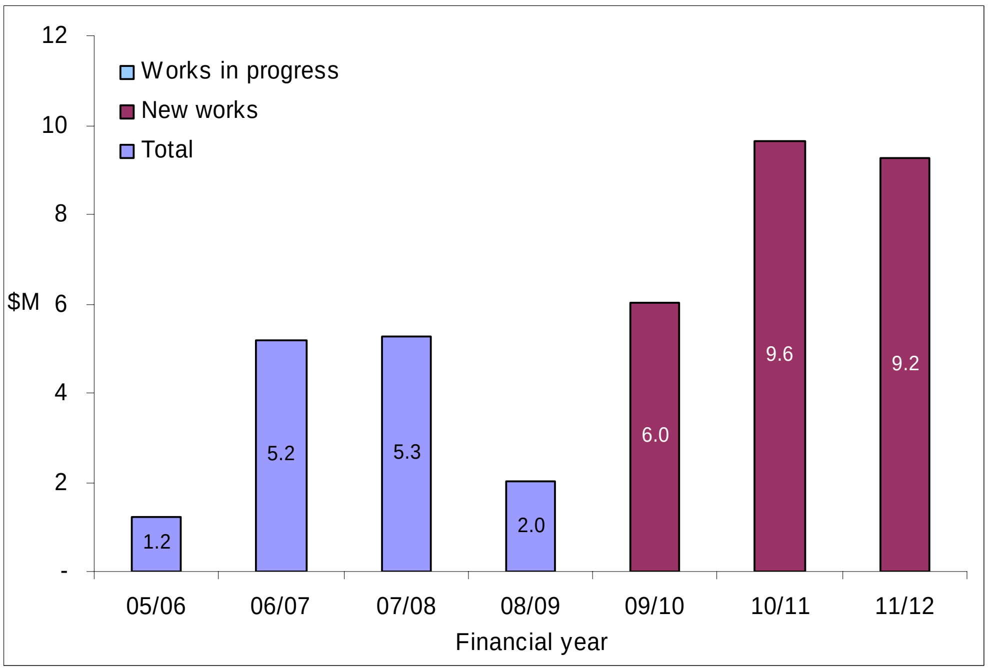
The balance of Western Power's RC Capex includes other technical requirements such as upgrading battery stands, improved substation earthing, a transformer bunding program, noise mitigation, transmission pole reinforcements and cross-arm upgrades.

5.8 Reliability Driven Capex[52]

Western Power's transmission based Reliability Driven (RD) Capex is associated with upgrade and augmentation work required to maintain the performance of the transmission network in the area of reliability. This may be in the form of specific projects or additions to other projects to achieve the targets in the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

In accordance with Figure 5-15, it can be seen that over the next regulatory period, it is proposed to materially increase the RD Capex from an average of $4M per annum in the 2006/07 to 2008/09 period, to an average of $8M per annum over the next regulatory period. This represents an increase of approximately 100%. Approximately $25M (1.2%) of Western Power's entire forecast Capex over the next regulatory period is attributed to reliability improvements, with all of the Capex associated with new works initiated in the 2009/10 to 2011/12 regulatory period.

Figure 5-15 – Transmission reliability driven capital expenditure ($M)



There are seven discrete transmission based reliability driven projects initiated over the 2009/10 period, with two being major projects with a value exceeding $2M, as outlined in Table 5-16.

52 Excludes estimating risk expenditure component

Table 5-16 – Transmission capital expenditure – RD projects ($M)

Project	09/10	10/11	11/12	Total
Reliability driven zone substation	3.30	6.60	6.80	16.7
Fault recording upgrade - stage 4	1.25	1.25	1.28	3.78
Reliability improvement pilot project - ground fault neutralizer	0.39	0.59	0.60	1.58
Wildlife proofing in zone substations	0.33	0.33	0.34	1.00
Implement 2MB comms to 7SD Relays	0.22	0.22	0.22	0.66
Removal of shared VTs	0.25	0.38	0	0.62
Upgrade to OPGW circuits	0.27	0.27	0	0.53
Total ($M)	**6.01**	**9.64**	**9.24**	**24.89**

Reliability driven zone substation

This project involves the building of a new substation in the hills of Perth primarily to improve the reliability of system performance in the Sawyers Valley and Byford areas. The feeders serving these regions, at 365km and 311km respectively, are much longer than is typical for metropolitan feeders and is a major contributing factor to the poor reliability being experienced. Constructing a new area substation will allow the number of individual feeders to be increased with a consequential reduction in the respective length of each feeder.

Fault recording upgrade - stage 4

Western Power has installed 16 fault recording devices around strategic locations in its network and is proposing to install an additional 15 over the 2009/10 to 2011/12 regulatory period. The fault recorders provide essential data that is necessary to predict and analyse major system disturbances (before and after the event). The work will fulfil Western Power's obligations as a Network Operator under the *Electricity (Supply Standards and System Safety) Regulations 2001.*

5.9 SCADA & Communications Capex[53]

Western Power's transmission based SCADA and communications Capex is related to the supervisory control and data acquisition (SCADA) system that provides the link between system operations and the primary system assets: the communications systems that carry SCADA information, tele-protection signalling information, voice communications and ancillary communications (such as Ethernet) to operational sites.

Relevant measures such as voltages, currents and plant status/condition are displayed to operational personnel in the control centres through a Master Station. The functionality of this system is integral to the real-time operation of the network and there are significant legal and consequential implications associated with failure of the system to the extent that its design warrants duplicated, fully redundant systems across multiple sites.

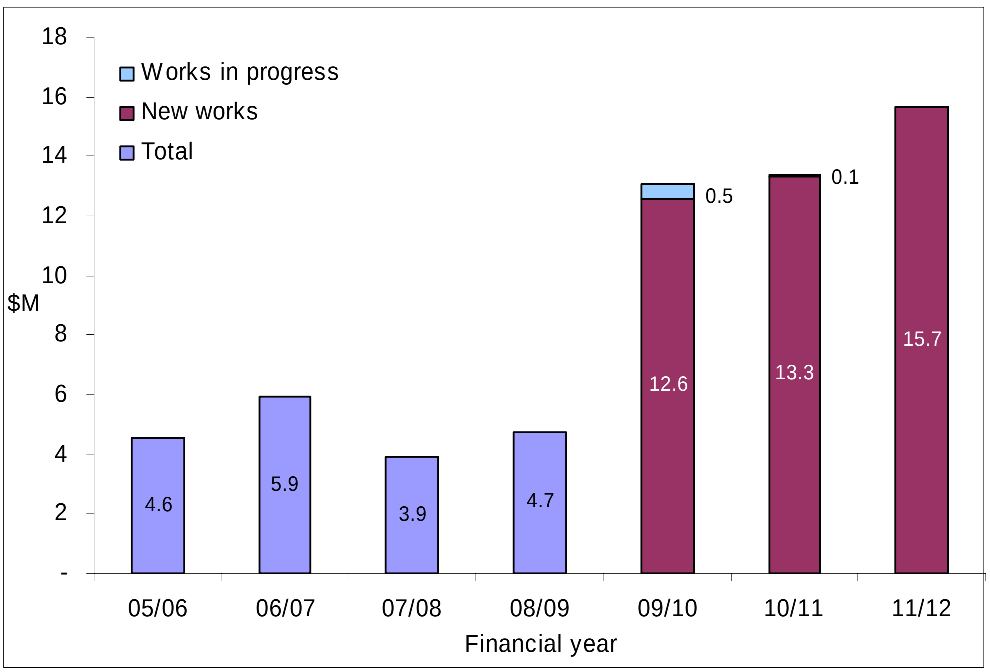
53 Excludes estimating risk expenditure component

This expenditure captures: the remote SCADA infrastructure and interlinking communications systems; the SCADA and communications components of capital works for new substations and generators; expenditure directly related to telecommunications for the provision of corporate information technology services; and SCADA Master Station capital works.

This expenditure excludes: the SCADA and communications components of capital works for new substations and generators; new technology and testing; and standards and policies.

In accordance with Figure 5-16, it can be seen that over the next regulatory period, it is proposed to increase the SCADA Capex from an average of $5M per annum in the 2006/07 to 2008/09 period, to an average of $14m per annum over the next regulatory period. This represents an increase of approximately 211%. Approximately $43M (2%) of Western Power's entire forecast Capex over the next regulatory period is attributed to SCADA and communications improvements, with $0.6M associated with work in progress and $42M associated with new works initiated in the 2009/10 to 2011/12 regulatory period. The balance of this section of the report is focused on the new works only.

Figure 5-16 – Transmission SCADA capital expenditure ($M)



There are twenty-eight discrete transmission based SCADA projects initiated over the 2009/10 period, with two being major projects with a value exceeding $3M, as outlined in Table 5-17. The projects have been grouped into six categories. The key drivers for each category are also noted.

- system operations, where the key drivers for expenditure are:
    - upkeep of the Energy Management System
    - long term software maintenance
- asset replacement, where the key drivers for expenditure are:

- ever-shortening lifecycles driven by the SCADA and telecommunications market, the knock on effect on spares availability, and limited third party maintenance
- the migration of protection and other circuits off pilot cables and onto contemporary technologies
- technology advances – extra function and capacity, less cost, greater bandwidth
- failing assets

- performance driven, where the key drivers for expenditure are:
    - systems and investment to support and improve upon corporate performance indicators
    - meeting regulatory requirements
    - meeting legislative requirements
- systems for Energy Solutions, where the key drivers for expenditure are:
    - leveraging technology and market movements
    - moving from traditional utility support systems into those that provide for condition monitoring, automation, intelligent grid, embedded generation, etc
    - integrated communications network management and monitoring to provide better decision support systems
- non-discretionary, where the key drivers for expenditure are:
    - third party actions, for example the retirement of Telstra services; retirement of Verve assets; and safety-related Capex
- core infrastructure growth, where the key drivers for expenditure are:
    - core infrastructure is nearing capacity and needs to be extended to support high-bandwidth applications
    - individual power-driven projects (e.g. substation build) are of a discrete nature and cannot justifiably fund all core network interconnections
    - to fill-in gaps in the core bearer networks to ensure redundant, high availability systems

Table 5-17 – Transmission capital expenditure – SCADA projects ($M)

Project	Type / number	09/10	10/11	11/12	Total
System operations	Master station	4.59	3.03	3.84	11.46
Pilot cables and associated system assets	Replacement	0	2.75	1.41	4.16
Asset replacement	10	1.03	2.99	6.63	10.65
Performance driven	2	1.20	0.88	1.32	3.4
Systems for Energy Solutions	3	0.49	2.21	1.46	4.16
Core infrastructure growth	5	2.21	1.25	0.78	4.24
General upgrades	5	3.05	0.20	0.21	3.46
Total ($M)		**12.57**	**13.31**	**15.65**	**41.53**

6 Transmission Forecast Operating Expenditure

In this section we discuss Western Power's transmission operating expenditure performance during the current regulatory period and also provide forecasts for all transmission maintenance and operational activities for the forthcoming regulatory period. Transmission operating expenditure includes maintenance (corrective and preventive), reliability penalty payments, SCADA and Communications, and Network Operations.

The expenditure forecasts for the next regulatory period shown in this section include all technical and business overheads associated with the individual cost categories but do not include business support costs (corporate overheads), which are detailed in Section 4. Comparisons between historical and forecast transmission operational expenditures, unless stated to the contrary, do not include business support costs.

6.1 Current regulatory period – actual and forecast expenditures

In this section we detail transmission Opex allowances and actual and forecast expenditures for the current regulatory period.

6.1.1 Regulatory Allowances

The annual transmission Opex allowances included in the Forecast Capital and Operating Expenditure Program **(FCOEP)**, for the current regulatory period 2006/07 to 2008/09 are shown in Table 6-1 in nominal dollars.

Table 6-1 – Transmission regulatory allowances for the current regulatory period including overheads ($M, nominal)

Item	05/06	06/07	07/08
Regulatory allowances	69.12	73.18	75.63

6.1.2 Expenditures in the current regulatory period

Table 6-2 details the regulatory allowances for transmission operational expenditure and the actual and forecast annual expenditures for the current regulatory period in 30 June 2009 dollars.

Table 6-2 – Comparison of transmission regulatory allowances and expenditures for the current regulatory period including business support costs ($M)

Item	06/07	07/08	08/09	Total
Regulatory allowances	74.40	78.77	77.89	231.06
Actual and forecast expenditures	75.96	75.55	74.52	225.27

The forecast expenditure for the 2008/09 financial year is expected to be approximately equal to the regulatory allowance.

6.2 Forecast expenditures

Forecast transmission Opex for the next regulatory period is shown in Table 6-3.

Table 6-3 – Forecast transmission Opex excluding corporate costs ($M)

Item	09/10	10/11	11/12	Total
Forecast Opex	73.51	77.93	84.07	235.51

The total forecast operational expenditures for the next regulatory comprise the recurrent and non-recurrent expenditures shown in Table 6-4.

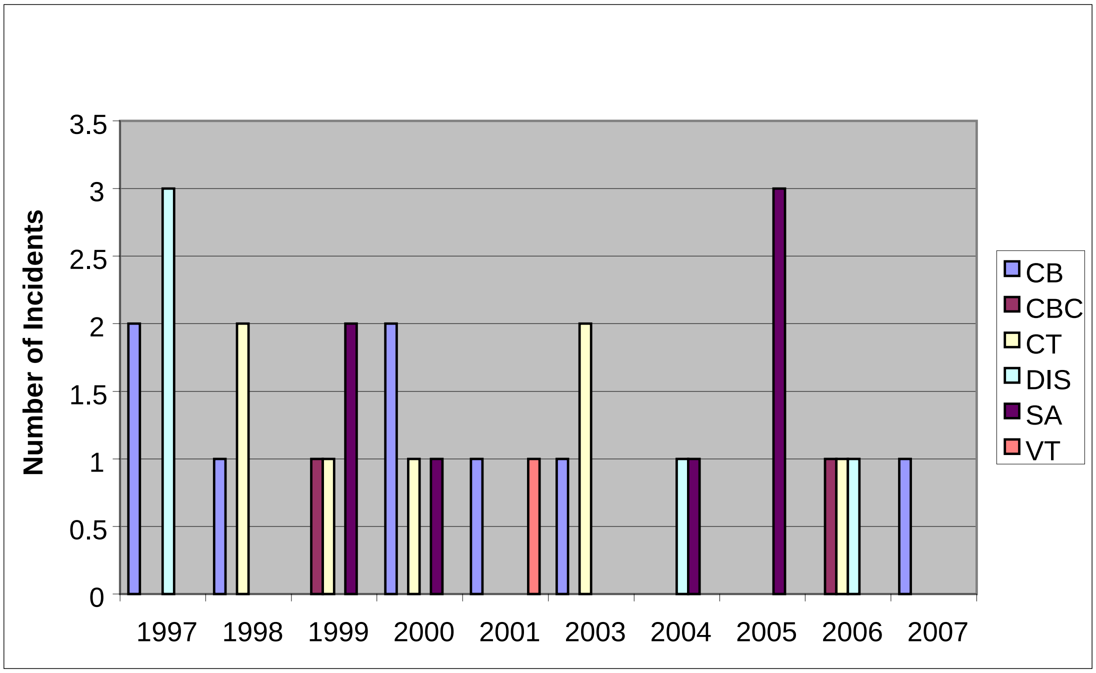
Table 6-4 – Forecast transmission Opex categories including cost and asset escalation and excluding corporate costs ($M)

Transmission Opex Categories	09/10	10/11	11/12
Preventative routine maintenance	21.42	22.65	23.91
Preventative condition maintenance	14.17	14.94	17.26
Corrective deferred maintenance	5.73	6.53	7.21
Corrective emergency maintenance	2.98	3.27	3.42
Non reference services	5.99	5.67	5.94
SCADA/communications	8.12	8.94	9.92
Network operations	12.92	14.00	14.70
Asbestos removal from Substations	1.63	1.38	1.14
Removal of redundant assets	0.54	0.55	0.57
Total (M)	**73.5**	**77.93**	**84.07**

In 2007/08 Western Power carried out a comprehensive review of all corrective transmission inspection and testing and the associated condition maintenance and repair works. The review was instigated as Western Power considered the current catastrophic failure rate to be unacceptably high for some transmission equipment. Recently there have been a number of catastrophic equipment failures in substations posing a safety risk to staff and causing collateral damage resulting in prolonged unplanned outages.

Figure 6-1 shows the number and type of catastrophic faults experienced in Western Power's transmission substations over the last ten years. Because of the safety implications involved, Western Power has an existing corporate target of zero explosive failures, which it is currently not meeting.

Figure 6-1 – Substation plant catastrophic faults



Note: CB= outdoor circuit breaker, CBC=indoor circuit breaker, CT= current transformer, DIS=disconnector, SA=Surge Arrester VT=voltage transformer

The review was a ‘bottom up’ investigation involving re-evaluation of asset quantities, asset maintenance policies, inspection periodicity, and consequential maintenance and repair works including unplanned repairs.

This review also included a ‘top down’ reasonableness test for all the individual major cost categories of the forecast expenditures. In particular the quantities of planned routine and preventative maintenance works were reviewed and the unit costs to carry out these works were re-estimated.

This comprehensive review has been designed to ensure that the transmission network operates in compliance with all current regulatory, statutory, safety and environmental requirements as well as delivering enhanced network reliability performance and reduced unplanned catastrophic asset failures.

The transmission Opex forecasts included in this submission reflect the outcomes of this review. If the additional inspections and maintenance and repair works are implemented Western Power expects that all stakeholders will see benefits accrue such as improved equipment performance, reduced unplanned asset failures and reduced expenditures on corrective emergency and deferred maintenance works over time.

6.2.1 Comparison of expenditures in current and next regulatory periods

Figure 6-2 and Table 8-5 details the actual and forecast operational expenditures for 2005/06, the current regulatory period and the operational expenditures forecast for the next regulatory period.

Figure 6-2 – Comparison transmission operating expenditure ($M)

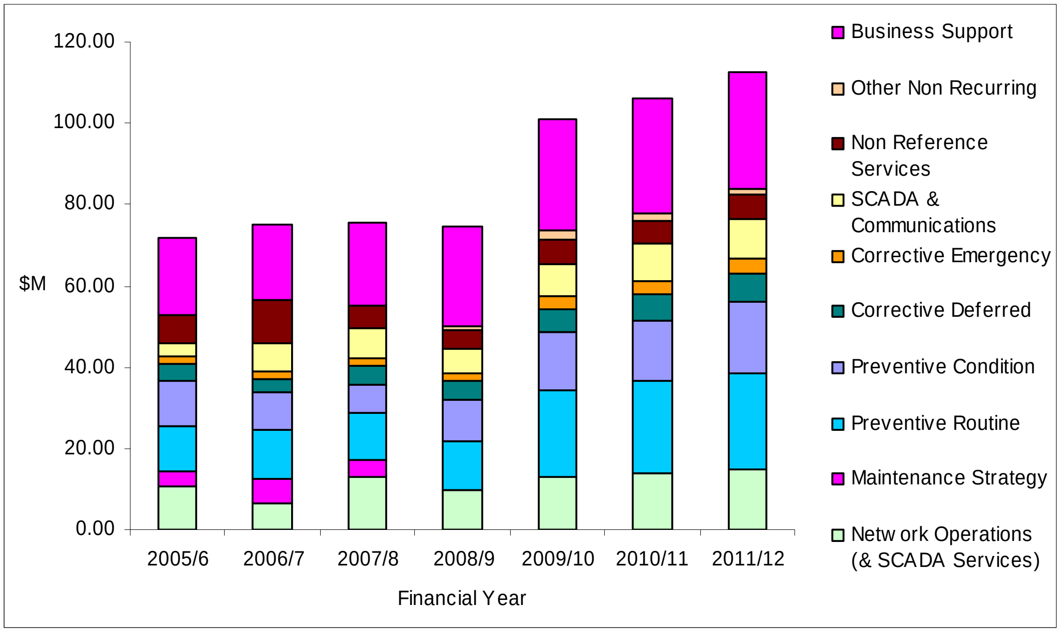


Table 6-5 – Comparison of actual and forecast Opex excluding business support costs ($M)

Item	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Maintenance strategy[54]	3.99	6.03	4.33	0	0	0	0
Preventive routine	11.06	11.84	11.74	12.09	21.42	22.65	23.91
Preventive condition	11.02	9.36	6.80	10.43	14.17	14.94	17.26
Corrective deferred	4.39	3.44	4.84	4.45	5.73	6.53	7.21
Corrective emergency	1.55	1.72	1.85	1.86	2.98	3.27	3.42
SCADA & communications	3.52	7.00	7.17	6.00	8.12	8.94	9.92
Non reference services	7.00	10.77	5.46	4.45	5.99	5.67	5.94
Network operations[55]	10.44	6.52	12.77	9.64	12.92	14.00	14.70
Other (non recurring)	0	0	0	1.30	2.18	1.94	1.70
Business support	18.93	18.54	20.63	24.30	27.39	28.04	28.70
Total (M)	**71.9**	**75.22**	**75.59**	**74.52**	**100.9**	**105.98**	**112.76**

54 Maintenance strategy activities are treated as a component of the direct overhead cost from 08/09 onward

55 Includes SCADA Services costs that support NOCC and SOCC mainframe SCADA systems etc.

6.2.2 Significant areas of proposed changes in expenditures

The following section describes the Opex categories where significant changes in expenditure are expected over the 2009/10 to 2011/12 regulatory period.

Increased asset quantities

Western Power proposes to implement a substantial transmission capital works program of approximately $2.19B over the 2009/10 to 2011/12 regulatory period. This will result in a considerable increase in the quantity of transmission assets requiring inspection and operation during the three year regulatory period. The forecasts include allowances to manage these additional assets which will be increasing at a rate substantially higher than historical growth rates.

The growth in transmission assets resulting from the proposed growth related capital works accounts for a significant percentage of the forecast Opex estimates.

Cost uplift

Western Power engaged an independent expert[56] to provide advice on the likely real increases in external labour and material costs expected over the next regulatory period. In addition, Western Power's HR department has provided guidance on the likely real increase in internal labour costs expected to be incorporated into rates as a result of enterprise bargaining.

In combination, significant real increases in both labour and material costs are expected over the next regulatory period and have been factored into the forward estimates. These real cost increases have a significant impact on the magnitude of the forecast expenditures.

Substation primary plant maintenance

This preventative routine maintenance function involves the inspection and minor maintenance of transmission primary plant. Currently it has been determined that approximately 60% of the maintenance activity detailed in the relevant maintenance policy is being carried out. This is a result of a combination of budgetary and resource constraints.

The transmission Opex forecasts for the next regulatory period provide for full compliance with the maintenance recommended in the relevant policies. As a result, forecast expenditure is expected to be approximately double that expected in the 2008/09 financial year. This is due to a combination of both increasing work volumes to prudent levels and cost uplift.

Secondary equipment maintenance

Expenditure on preventative routine maintenance is forecast to approximately double between 2008/09 and 2009/10. Current expenditure reflects the fact that only approximately 60% of the maintenance works required under the relevant asset maintenance policy is being undertaken. This is principally due to resource constraints as specialist resources had to be diverted to the capital works program.

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56 Access Economics, 2008, *Material and Labour Cost Escalation Factors*, DMS 4575552

The expenditure estimate for the next regulatory period includes 100% of the maintenance works required under the relevant asset maintenance policy. The forecast estimate includes the additional planned works and anticipated cost uplifts.

Substation HV equipment testing

Current expenditure reflects approximately 50% of the testing required by the relevant asset maintenance policy. Testing is currently limited by resource restraints and the ability to gain access to the equipment due to system loading constraints.

Forecast substation HV equipment testing expenditures for the next regulatory period reflects 100% of tests specified in the relevant asset management policy and current costs. Western Power will use resources released by the abolition of equipment warranty testing and program tests for periods of low system demand when existing constraints will be substantially reduced as a result of the proposed capital works program.

Warranty inspection and testing

Forecast expenditure for this preventative maintenance category is expected to reduce over the next regulatory period as Western Power intends to focus its efforts on pre-commissioning testing with a substantial reduction in equipment testing prior to the end of the warranty period. The existing end of warranty testing program was finding very few problems whilst consuming critical specialist resources.

Expenditure in the next regulatory period is forecast to be approximately $503,000 less than expenditures previously anticipated for the last year of the current regulatory period (2008/09). This proposal will also free-up resources for other transmission works; however there will be a corresponding increase in commissioning costs associated with the proposed capital projects.

Silicon application to insulators

Sylgard protection applied to transmission insulators reduces pole top fires and also reduces television interference. This has been a very effective strategy that has been deployed for a number of years. The increase in forecast expenditures is approximately twice that anticipated for 2008/09 financial year. The increase is a result of uplift in unit costs rather than an increase in insulator quantities as quantities are forecast to remain constant over the next regulatory period.

Overhead lines maintenance

Overhead line maintenance relates to the correction of conditions identified from inspections, and includes maintenance carried out from ground level, via helicopter platform or using live line techniques. Overhead line inspections include both inspection and rectification of the conditions found. Recent condition assessments have identified defect rates that are significantly higher than previously estimated. Expenditure for the preventive maintenance category is therefore forecast to increase over the forthcoming access agreement period.

Expenditure for this preventative maintenance category is forecast to rise by approximately $4.2m between the final year of this regulatory period (2008/09) and 2009/10.

6.2.3 Estimating methodology

The method used to arrive at an initial estimation of forecast costs for transmission Opex is to use the recent internal and/or contract service costs to determine the average historical costs for inspections, maintenance and repair works. Where it is known that new contracts have been agreed then these costs have been incorporated into the estimates.

These initial unit costs were reviewed by field staff for reasonableness and to ensure that the material cost and labour times included in the average unit costs are reflective of current practice. Much of the transmission maintenance works are specialised in nature and are of low volume, so the development and use of an estimating system such as Distribution Quotation Management System (DQM) – which is used for cost estimation associated with high volume distribution assets, is not viable for transmission works.

6.2.4 Preventative maintenance

Preventative maintenance includes preventative routine maintenance and preventative condition maintenance.

Transmission Preventive Routine Maintenance is the proactive maintenance carried out to reduce the probability of failure or the degradation in performance of transmission network assets. The activities include the monitoring, testing or inspection of equipment that is undertaken either at predetermined intervals or is initiated by equipment operations or condition. This work typically includes visual inspection, testing, lubrication regimes and routine minor part replacement.

Preventive Condition Maintenance costs relate to the follow-up maintenance activities performed as a result of conditions/defects identified through preventive routine maintenance programs.

The review of preventative maintenance was conducted by developing 81 individual activity templates for all significant transmission maintenance activities. One of the outcomes of this detailed and comprehensive review has been the establishment of prudent work volumes for the 2009/10 financial year.

Forecast operational estimates have been prepared based on these work volumes and unit costs developed as detailed in Section 6.2.3. Large real increases in internal and external labour and material costs and increased volumes arising from the proposed capital works program during the next regulatory period have a significant impact on the forecast preventative maintenance expenditures.

In addition preventative condition maintenance also includes removal of a backlog of transmission conditions outstanding from the current regulatory period which will be carried over into the next period. This backlog was quantified by searching the Ellipse database to identify and collate all outstanding preventative condition maintenance (K2) conditions currently logged as open. The data was cleansed to remove double counts etc and then analysed for reasonableness.

Preventative condition maintenance also includes the inspection of transformers susceptible to winding displacement and failure when subjected to through fault current. Transformers are re-clamped when required. This project was commenced during the current regulatory period and has resulted from a type fault being identified. The project is expected to span 5 years. An activity template detailing the complete program is available.

In addition Western Power is installing tamper proof locking nuts to all bolts on the lattice towers below the anti climbing guards to prevent theft of tower members and to secure the tower footings. Western Power is taking a risk based approach to the remediation work and has identified that 2% of the 6,546 lattice towers in the transmission systems that are located near population centres and hence would be more susceptible to intrusion and theft.

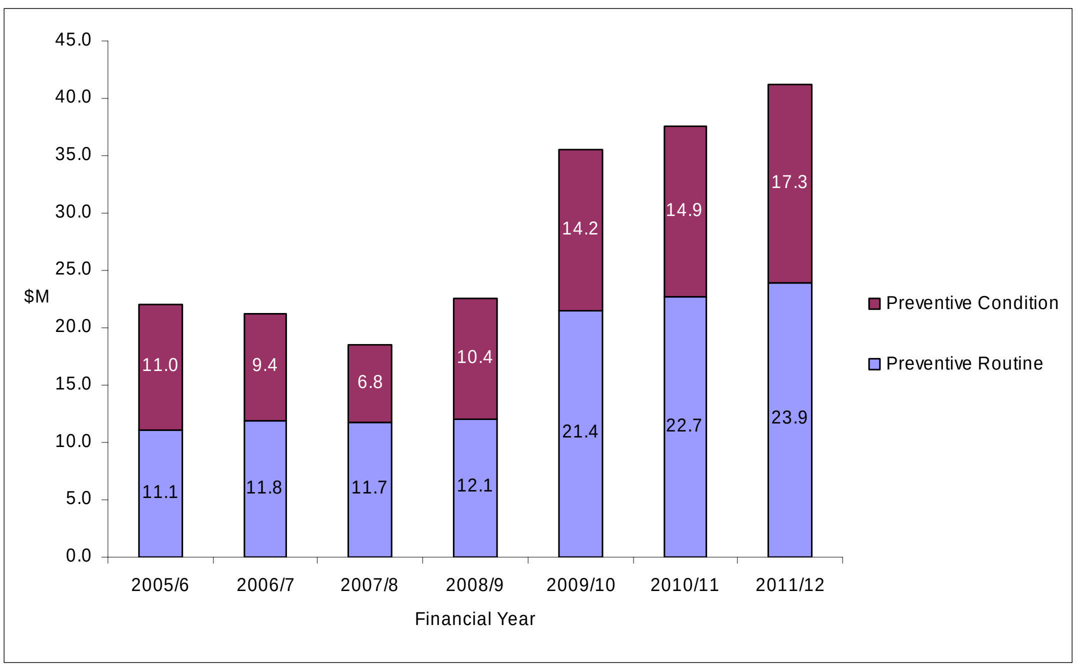
As this project has been assessed as posing a moderate risk it is proposed to carry out this program over a 5 year period and hence 26 towers per annum have been included in forecast expenditures over the next regulatory period.

Table 6-6 – Transmission preventative maintenance actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Preventive routine maintenance	11.84	11.74	12.09	21.42	22.65	23.91
Preventive condition maintenance	9.36	6.80	10.43	14.17	14.94	17.26

Note: Historical data excludes strategic planning support costs.

Figure 6-3 – Transmission preventive maintenance expenditure ($M)



6.2.5 Corrective maintenance

Corrective maintenance comprises corrective deferred maintenance and corrective emergency maintenance. Corrective deferred maintenance includes the repair of failed or damaged equipment that does not present an emergency situation. These works usually arise following an emergency supply restoration where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the works or rebuild the assets at a later stage.

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 an accident, an unplanned equipment failure or inclement weather. The need for 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.

Corrective maintenance forecasts for the next regulatory period have been developed by applying linear regression analysis to historical real data. The methodology implies that the impact of the proposed additional preventative maintenance will not be significant until after the end of the next regulatory period. Western Power believe that this is a reasonable proposition as the lag between increasing maintenance and reduced unplanned or unassisted asset failures is usually several years.

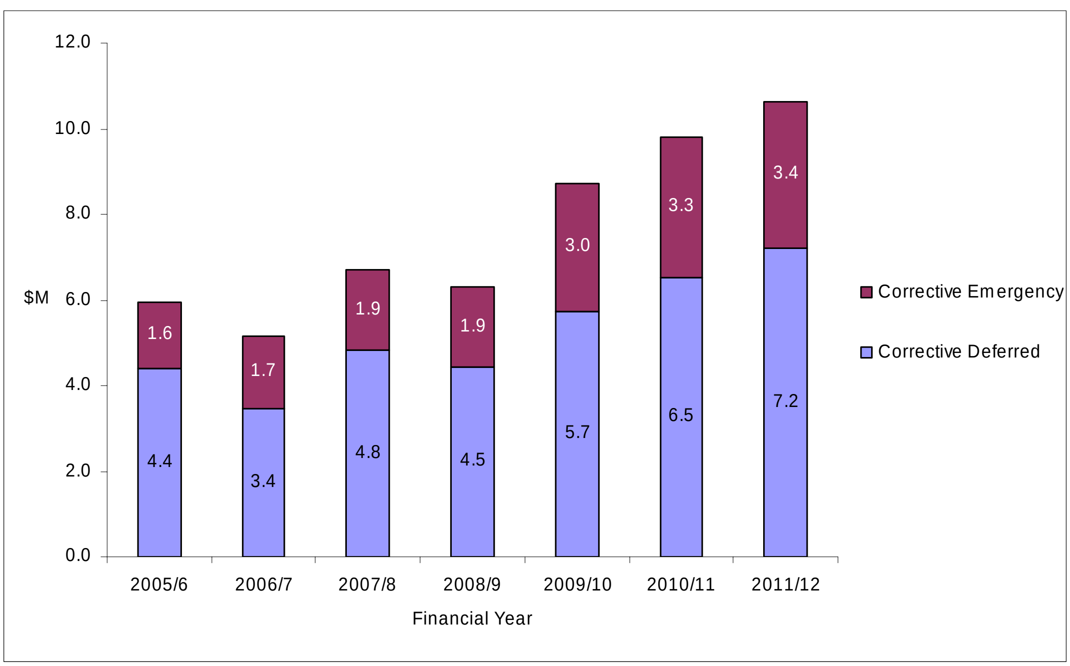
The corrective emergency maintenance and corrective deferred maintenance forecast expenditures for the next regulatory period are detailed in Table 6-7. Large real increases in internal and external labour and material costs and increased volumes arising from the proposed capital works program during the next regulatory period have a significant impact on the forecast corrective maintenance expenditures.

Table 6-7 – Transmission corrective maintenance actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Corrective emergency Maintenance	3.44	4.84	4.45	5.73	6.53	7.21
Corrective deferred maintenance	1.72	1.85	1.86	2.98	3.27	3.42

Note: Historical data excludes strategic planning support costs.

Figure 6-4 – Transmission corrective maintenance expenditure ($M)



6.2.6 Network operations

Transmission network operational expenditure includes 50% of the System Management administration costs, maintenance of the XA/21 Energy Management System, 50% of the operating expenses of the SCADA & Information Systems Branch. It also includes operating costs of the Operations Control Branch, operating costs of maintaining the Emergency Backup Control Centre and the costs of providing a network control service. A brief description of each function is provided below.

System management

This expenditure category includes 50% of the operational costs of System Management administration. System Management covers both the transmission and distribution network operation and management and hence costs have been allocated 50% each to distribution and transmission Opex.

Energy Management System

The XA/21 Energy Management System (EMS) is the SCADA Master Station at the East Perth Control Centre that provides System Operations visibility and control of the generation and transmission network and data to support the electricity market.

The forecast expenditure associated with EMS is required to maintain legal, regulatory and operational requirements. It will also provide for the continuous (24x7) security of the EMS, ensure the reliability and performance of the EMS, apply software and security patches as they become available and investigate and correct system operational issues raised by System Operations and Regulatory authorities.

SCADA & Information Systems branch

The expenditure forecast for this function includes 50% of the operating costs of the SCADA & Information Systems branch. This branch manages the operations of the SCADA Master Stations to provide “real time” visibility and control capabilities to support the System Management Division. This is a critical facility required for the operation of the transmission network and the operating costs of this branch are shared with the distribution NOCC.

These costs relate primarily to the staffing costs such as recruitment, training and development and health and safety activities and the software maintenance and licence costs associated with the XA/21 Energy Management System.

Operations Control branch

The expenditure forecasts for this function include the operating costs of the Operations Control Branch which ensures the safe, secure and reliable operation of the South West Interconnected System on a daily basis. This includes ensuring that the power system is operated within defined guidelines and that the quality of supply is in accordance with regulations. Prudent operation of the network preserves the service life of assets by operating equipment within defined limits, ensuring that market participants are compliant with the market rules and also ensuring that System Management operates in accordance with the market rules.

Emergency backup control centre

This expenditure relates to the provision of an alternative transmission system control facility to provide critical back-up in the event of a need to evacuate the East Perth Control Centre (EPCC). The Western Australian Energy Market rules require the provision of back-up control centre facilities.

It is proposed to relocate this facility to Head Office during the next regulatory period. The NOCC back up control centre is currently located at head office and there are a number of benefits in co-locating the two back up control rooms at the same location. These advantages include ease of testing IT equipment, sharing of communications facilities with the NOCC, improved telephone facilities and faster establishment times.

Network reliability contracts

The network reliability contracts expenditure relates to contracts for the provision of synchronous compensator capability for voltage support at generators located at strategic points of the network, and contracts for provision of remote area restart.

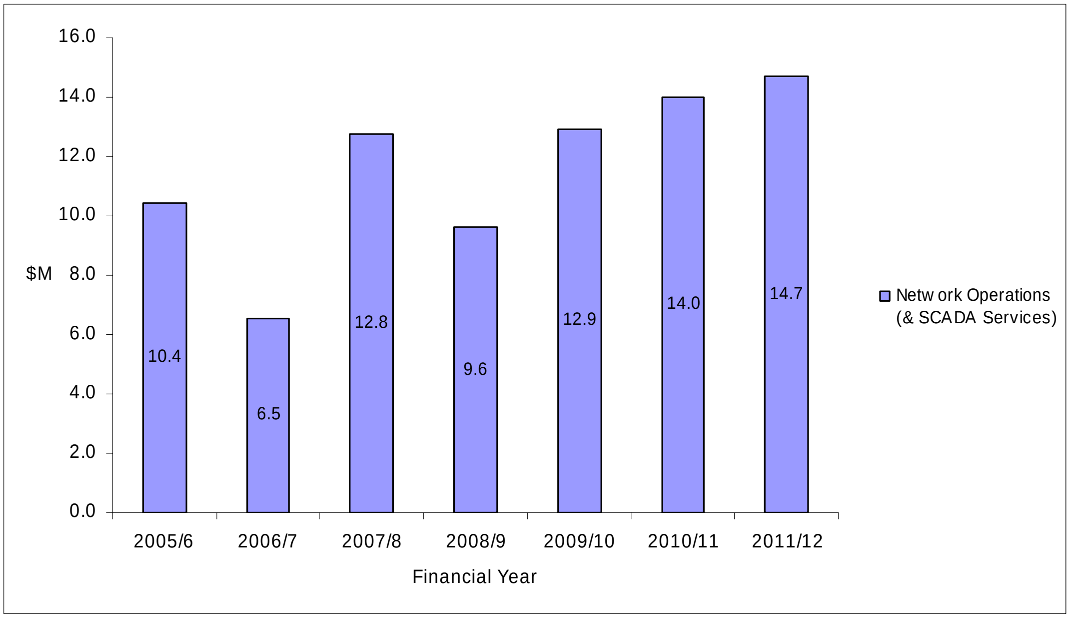
It is necessary for this service to be provided for system security and reliability reasons. The alternative is to carry out network augmentation, and currently the network reliability contracts are more cost effective.

It is envisaged that the contracts will be required for the entire next regulatory period, and the situation will be reviewed after that time.

Table 6-8 – Transmission network operations actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Network operations	6.52	12.77	9.64	12.92	14,00	14.70

Figure 6-5 – Transmission network operations expenditure ($M)



6.2.7 SCADA and communications

Transmission SCADA and communications includes the strategic planning and asset management, as well as the preventative and corrective maintenance for all communication and SCADA field assets. It also includes all the communications operations network management monitoring and control and the management of all licensing and 3rd party support.

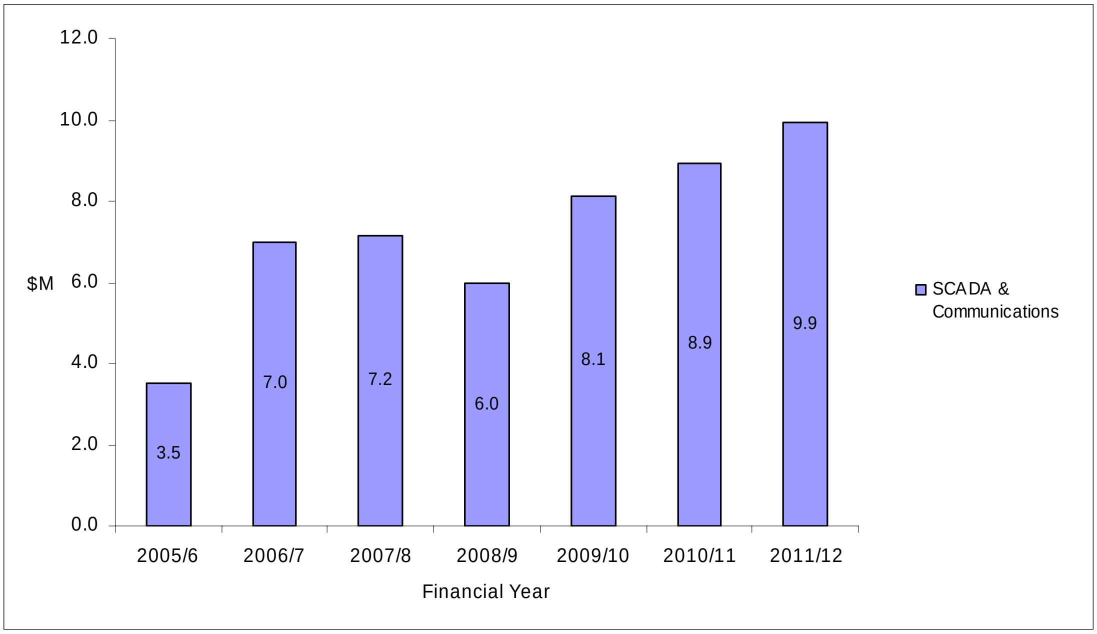
Transmission Opex is forecast to increase over the next regulatory period with the increasing number of assets being managed. Asset growth is forecast to continue at 10% per annum plus an additional 10% resulting from the Smartgrid initiatives. The increased forecast operational expenditure relates primarily to the cost of employing more technicians to manage and maintain the additional assets. The growth in operational expenditures is moderated by asset condition monitoring improvements and asset replacement with advanced functionality. There is a small step change in 2009/10 when SCADA field maintenance Opex costs will be included in this category.

Table 6-9 details the transmission SCADA and communication forecast expenditures included in the total transmission Opex forecasts for the next regulatory period.

Table 6-9 – Transmission SCADA and communications actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
SCADA & Comms.	7.00	7.17	6.00	8.12	8.93	9.92

Figure 6-6 – Transmission SCADA & communications expenditure ($M)



6.2.8 Non Recurrent Transmission Opex

The transmission non recurrent operating Opex comprises two projects as follows:

Removal of redundant transmission assets

This program involves the removal of transmission network assets stranded as a result of supply no longer being required and remediation of the line easement. Typically, this follows situations such as mine closures, etc.

Removal of redundant transmission network assets also reduces the network exposure to fault interruption. This scheme is not intended to apply to instances of decommissioning associated with load increase. The removal of existing assets in this instance would be included in the capital cost associated with augmentation.

The forecast annual expenditure of $550,000 is based on historical costs for environmental remediation, plant and line deconstruction and historical expenditure profiles for this type of work over the previous three years.

Table 6-10 – Removal of redundant transmission assets forecast expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Redundant assets	0.54	0.55	0.57	1.66

Asbestos removal from substations

A total of 96 substation sites are known to contain asbestos in the form of asbestos cement building products (eaves, walls, ceilings, roofs, capping, bargeboards, infill panels, fascias, fences, pipes, gutters, conduits, boards, boxes and arc chutes), resinous material containing asbestos (electrical backing boards and vinyl floor tiles), debris and insulation materials.

This project is ongoing and is driven by acknowledged health and safety risks and is governed by appropriate regulations. Due to funding constraints only the highest priority works will be completed by June 2009 and it is proposed to continue the remediation works throughout the next regulatory period.

An Asbestos Containing Materials Register has been produced for asbestos-containing material (ACM) identified at each substation and terminal site. The register includes an assessment of the level of risk associated with each asbestos situation, with the risks being graded 'High (P1)', Medium (P2)' or 'Low (P3)' risk rating.

The total cost of removal of all of the asbestos contained within Western Power substations would be in excess of $22M. Capital expenditure has been included in the submission to remove the 'High and Medium risk' asbestos situations over the next 3 years. This still leaves the majority of the asbestos in situ. This proposal aims at dealing with the operational issues arising from retaining this 'Low risk' asbestos within the asset base and managing its deterioration.

The first three years forecast expenditures for this program have been included in total transmission Opex forecasts for the next regulatory period, as detailed in Table 6-11.

Table 6-11 – Asbestos removal from substations forecast expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Asbestos removal	1.63	1.38	1.14	4.15

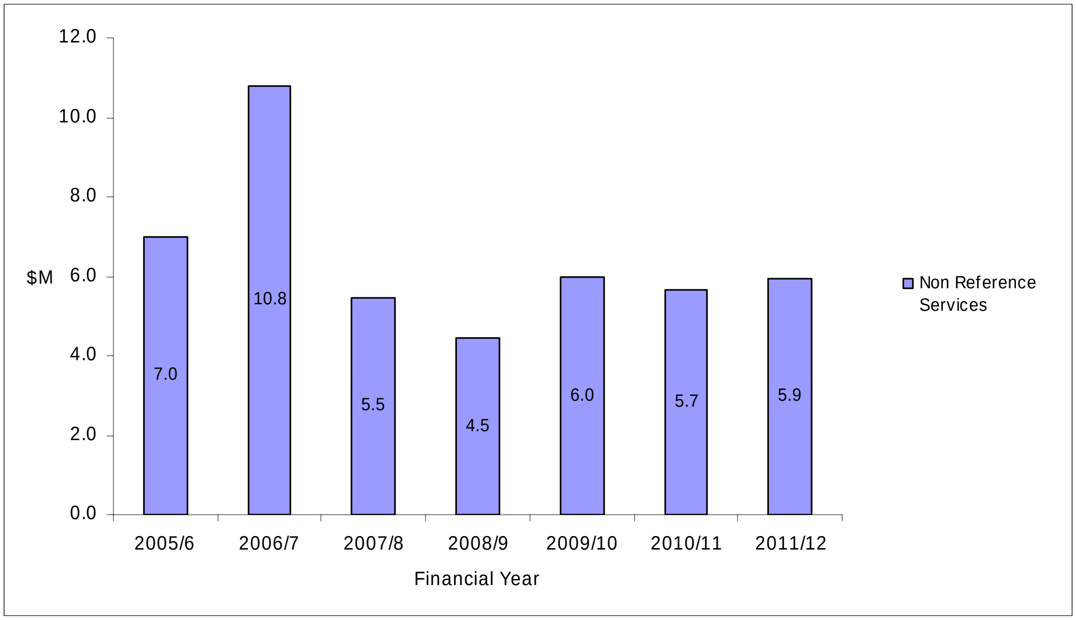
6.2.9 Non Reference Services (NRS)

The expenditure for the miscellaneous support services covered by NRS has increased significantly, particularly for activities impacted by the high level of state economic activity – for example the relocation of incumbent assets for industrial, commercial and residential land and property developments.

Table 6-12 – Comparison of transmission actual and forecast Opex Non Reference Services expenditures ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Non Reference Services	10.78	5.46	4.45	5.99	5.67	5.94

Figure 6-7 – Transmission non reference services expenditure ($M)



6.3 Labour and material escalators

Western Power has commissioned an independent expert[57] to provide a forecast of real increases in wages for WA Utility Workers and combined materials for distribution and transmission operating and capital works. Table 6-13 details the recommendations of this study in relation to WA utility workers and transmission operating materials. In determining the real escalation for transmission materials, the report has relied on Western Power to supply details of a typical 'bundle' of transmission operating materials.

Table 6-13 – Access Economics forecast real cost escalators

Item	07/08	08/09	09/10	10/11	11/12
WA utility workers wage escalation	5.84%	4.92%	4.54%	4.12%	4.78%
Transmission operating Materials	2.29%	9.35%	3.60%	1.43%	6.23%

Source: Access Economics

In addition, Western Power HR department has indicated that current negotiations for an enterprise agreement for internal staff will result in real wage escalation for internal labour as detailed in Table 6-14.

57 Access Economics, 2008, *Material and Labour Cost Escalation Factors*, DMS 4575552

Table 6-14 – Western Power forecast real escalation for internal labour

Item	07/08	08/09	09/10	10/11	11/12
Western Power real labour escalation	5.00%	6.50%	6.00%	6.00%	5.50%

Source: Western Power

The cost estimates for transmission Opex forecasts include real internal labour, contract services and material cost escalation, but do not include any contingencies. The cost escalation is applied in an Opex model which includes composite cost escalators for each major Opex category based on the proportion of internal labour, contract services and materials in each category.

The transmission Opex model is also used to incorporate the impact of growth in the assets under management during the next regulatory period resulting from the planned growth related capital works. In addition the impact of the proposed refurbishment/replacement Capex on forecast Opex is also incorporated in the model. Cost and asset escalation has been included in the transmission operating forecasts at a cost category level rather than on a global level to facilitate comparison of forecasts with current regulatory period actual and forecast expenditures.

6.4 Additional Opex requirements resulting from growth Capex

Western Power has used the magnitude of the proposed growth related levels of Capex to determine the additional Opex required to manage these additional assets. In the transmission Opex model the ratio of transmission growth related capital expenditure to the current Western Power transmission asset base replacement cost is calculated on an annual basis with the proposed capital expenditure compounded year on year. The resulting annual ratios are then reduced by 18% to compensate for the fact that no condition maintenance expenditures are expected to be incurred by these new assets over the next regulatory period. This percentage reduction has been calculated using the transmission Opex model.

These calculations are detailed in the transmission Opex model and are applied in conjunction with the escalation resulting from the forecast real increases in internal labour, contract services and materials.

The total growth-related forecast capital expenditure includes a substantial component of land and easement purchases. As this expenditure is not directly related to the growth in transmission assets these proposed capital purchases have been removed from the total growth related capital expenditure forecasts for these calculations.

The forecast annual transmission growth related capital expenditures adjusted to remove proposed land purchases are detailed in the following Table 6-15.

Table 6-15 – Transmission growth related capital expenditure ($M)

Item	09/10	10/11	11/12	Total
Growth Capex	589.2	726.8	463.9	1779.9.0

Western Power has calculated the current replacement cost of its transmission assets to be $6.56B and this number has been used in calculating the ratio of future growth related capital expenditure to the current replacement cost of the transmission asset base. This calculation is based on current replacement costs and includes Western Power's costs as well as construction costs.

6.5 Opex/Capex trade-off

Western Power has incorporated a trade off in forecast transmission Opex resulting from the proposed asset replacement /refurbishment Capex over the next regulatory period. It is widely acknowledged that replacing or refurbishing assets at or near the end of their operational lives results in reduced Opex.

The reduction relates to avoidance of corrective maintenance works for new assets but they still require operation, preventative maintenance inspections and corrective maintenance etc. This reduction has been calculated to be 18% of the costs of maintaining and operating assets with approximately half their service lives remaining. This is the ratio used in the Opex model to estimate that Opex savings resulting from the proposed capital expenditure on replacement and refurbishment. The forecast annual refurbishment/replacement capital expenditures used in these calculations are detailed in Table 6-16.

Table 6-16 – Transmission replacement/refurbishment capital expenditure ($M)

Item	09/10	10/11	11/12	Total
Replace/refurbishment Capex	95.6	95.4	100.8	291.8

Western Power has calculated the current replacement cost of its transmission network assets to be $6.56B and this number has been used in calculating the ratio of future capital expenditure on refurbishment and replacement to the current replacement cost of the transmission network asset base. This calculation is based on current replacement costs and includes Western Power's costs as well as construction costs.

6.6 Total forecast transmission operating expenditures

The total annual transmission forecast operating expenditures for the next regulatory period have been determined by:

- including the real forecast cost increases in labour, contract services and material over the period
- including the impact of growth related distribution Capex on forecast Opex
- including the reduction in Opex expected from the proposed transmission replacement/ refurbishment Capex
- excluding corporate overheads.

The total transmission Opex forecast is shown in Table 6-17.

Table 6-17 – Forecast transmission Opex including cost and asset escalation ($M)

Item	09/10	10/11	11/12	Total
Total forecast ($M)	73.51	77.93	84.07	235.51

7 Distribution Forecast Capital Expenditure

In this section, we set out the forecast distribution Capex required for the next regulatory period. The expenditures for each activity type are presented and the reasons for changes in expenditure levels from previous years are discussed.

7.1 Overview

Western Power is proposing to invest $2.29B during the next 3 year regulatory period on its distribution asset base. Figure 7-1 and Table 7-1 provide the historical and projected capital expenditures. It can be seen from Figure 7-1 that it is proposed to increase the distribution capital expenditure from an average of $502M per annum in the 2006/07 to 2008/09 period to an average of $763M per annum over the regulatory period. This represents an increase of approximately 52%, of which approximately 46% is driven by growth related demand, while the balance is related to enhanced asset replacement practices, network reliability improvements, changing standards, and compliance with changing safety, statutory and environmental requirements.

The drivers of this increased expenditure were outlined in Section 2, while the following sections provide an overview of the distribution capital expenditure over the regulatory period.

Figure 7-1 – Distribution capital expenditure

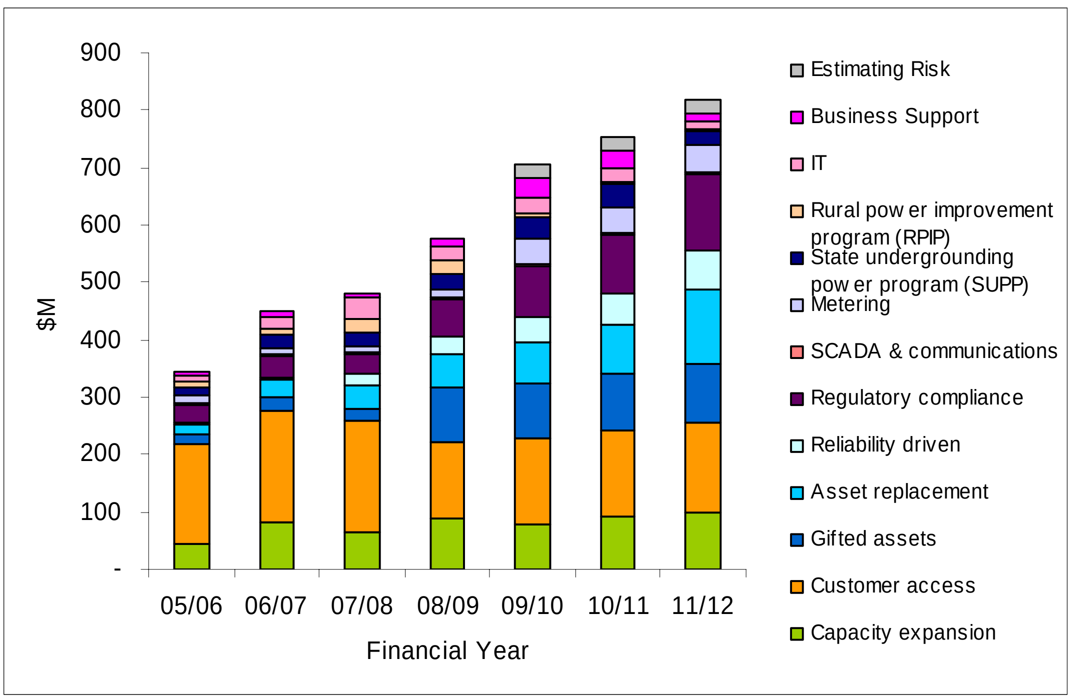


Table 7-1 – Distribution capital expenditure ($M)

Expenditure category	05/06	06/07	07/08	08/09	09/10	10/11	11/12
GROWTH							
Capacity expansion	44.76	81.67	63.23	89.20	77.78	90.59	97.30
Customer access	171.81	194.8	195.15	131.89	149.16	151.93	157.61
Gifted assets	18.54	23.67	20.91	94.30	97.92	99.74	103.47
Estimating Risk (3.5%)	*0*	*0*	*0*	*0*	*11.37*	*11.98*	*12.54*
ASSET REPLACEMENT & RENEWAL							
Asset replacement	15.68	29.37	39.65	61.14	71.48	84.26	128.83
State undergrounding power program (SUPP)	15.48	22.66	22.66	29.29	35.32	38.41	22.69
Metering	13.07	11.52	12.77	12.60	45.63	46.06	47.69
Estimating Risk (3.5%)	*0*	*0*	*0*	*0*	*5.34*	*5.91*	*6.97*
IMPROVEMENT IN SERVICE							
Reliability driven	6.17	5.90	19.16	28.78	44.41	54.41	67.40
Rural power improvement program (RPIP)	7.32	10.35	23.69	22.00	8.41	5.40	3.13
SCADA & communications	2.61	2.41	2.16	2.57	5.91	5.93	5.93
Estimating Risk (3.5%)	*0*	*0*	*0*	*0*	*2.06*	*2.30*	*2.68*
COMPLIANCE							
Regulatory compliance	27.72	36.54	35.74	65.57	88.53	103.14	135.10
Estimating Risk (3.5%)	*0*	*0*	*0*	*0*	*3.08*	*3.62*	*4.73*
CORPORATE							
IT	10.82	19.35	34.99	24.58	27.30	21.90	13.34
Business support	6.44	9.77	9.35	13.55	34.91	33.00	13.59
Total (M)	**340.44**	**448.03**	**481.29**	**575.47**	**708.60**	**758.55**	**823.00**

7.2 Distribution capacity expansion[58]

Figure 7-2 shows the historical and forecast distribution capacity expansion capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the next regulatory period, it is proposed to increase the distribution capacity capital expenditure from an average of $78M per annum in the 2006/07 to 2008/09 period, to an average of $88.7m per annum over the next regulatory period. This represents an increase of approximately 14%.

The magnitude and timing of distribution capacity capital expenditure is driven by two key inputs to the distribution capacity planning process; they are, transmission capital works (refer Section 5), and the application of Western Power's distribution network planning criteria under forecast load growth.

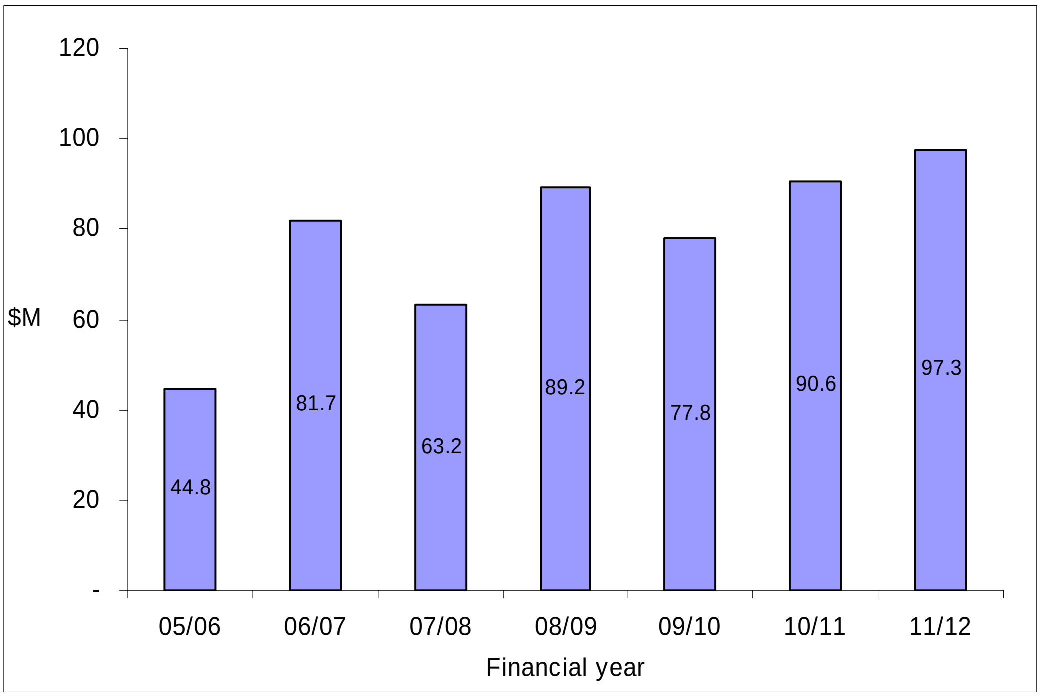
[58] Excludes estimating risk expenditure component

Distribution capacity projects can be divided into the following categories:

- transmission driven
- HV reinforcement
- distribution transformer overload upgrades & LV network optimisation.

Specific details of the distribution capacity management strategies associated with each of these sub-categories are outlined in the following subsections.

Figure 7-2 – Distribution capacity capital expenditure ($M)



7.2.1 Transmission driven

This category of distribution capital works is driven by transmission network projects that are planned to be undertaken by Western Power during the next regulatory period. While the need for the related transmission projects is the key driver for this category of work, the specific need for the distribution project arises out of the need to:

- maintain clearances between distribution and transmission assets as transmission lines are developed or augmented
- manage the thermal capacity limits of HV distribution feeders under continuous and fault conditions to comply with Western Power's distribution planning guidelines[59]

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59 Western Power's planning criteria require feeder loads to be kept below 80% of their Normal Cyclic Rating, so that one feeder can be offloaded to four other feeders under emergency conditions. For metropolitan distribution planning standards refer to DMS 4489792. For rural distribution planning standards refer to DMS 917435.

- 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[60].

The drivers and justification for these works are discussed in section 5 for each of the associated transmission projects. Reference should also be made to the supporting transmission business cases for additional detail on the need and justification for these works. It should also be noted that the listed transmission driven projects are dependent on the need and timing of the related transmission projects. Where the requirements of the related transmission projects change, this will impact on the need and timing of the transmission driven distribution capital works.

Each distribution capacity project in this category addresses the needs of an associated transmission project, as well as the requirements of the Technical Rules in terms of network planning standards, network contingency criteria, and power quality. Each project also meets at least one leg of the New Facilities Investment Test (NFIT) of the Access Code. Generally, transmission driven distribution capacity expansion projects meet the commercial leg (i.e. investment option is assessed as prudent and the NPV is at least zero).

Table 7-2 shows the total forecast transmission driven distribution capital works expenditure required over the regulatory period. This forecast has been built up from the underlying distribution network projects required to support the development of the transmission network. Individual project estimates are based on a high level project scope of works.

Table 7-2 – Transmission driven distribution expansion Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Transmission driven Capex:				
- Metropolitan area	22.98	37.11	34.84	94.93
- Rural areas[61]	2.30	6.95	7.27	16.52

7.2.2 HV reinforcement

Reinforcement of Western Power's HV distribution network is undertaken in order to meet the requirements of future load growth, while maintaining network operation within planning criteria limits. Consequently, these works are driven by:

- forecasts of future demand at each zone substation and for each distribution feeder

- specific new developments (e.g. residential subdivisions, embedded generation)

- network changes that impact the performance of elements of the distribution network (e.g. network reconfiguration, un-associated network augmentations)

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60 This need may arise in order to defer transmission projects through improved utilisation of existing capacity in an adjacent area.

61 Rural areas are North Country, South Country, and Goldfields.

- the operational, control, and data needs of network management.

In response to these drivers, Western Power undertakes distribution HV reinforcement works to ensure that:

- the thermal capacity limits of HV distribution feeders are managed under continuous and fault conditions so as to comply with Western Power's distribution planning guidelines[62]
- network operability and reliability is maintained[63]
- feeder voltage profiles are maintained within the required Technical Code requirements[64]
- network equipment, connected installations, the environment, and the public are protected from network faults, and that protection arrangements comply with the Technical Code requirements.

It should be noted that as the drivers for this category of work are dynamic in nature, the list of projects in this category are subject to change.

Each HV reinforcement project in this category addresses the needs outlined above in accordance with Technical Rules in terms of network planning standards, network contingency criteria, and power quality. Each project also meets at least one leg of the NFIT. Generally, HV reinforcement projects meet the commercial leg of the NFIT.

Table 7-3 shows the total HV reinforcement distribution capital works expenditure required over the regulatory period. This forecast has been built up from the underlying distribution network projects required to meet future load growth requirements while maintaining network operation within planning criteria limits. Individual project estimates have been based on a high level project scope of works for each project.

Table 7-3 – HV reinforcement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
HV reinforcement Capex:				
- Metropolitan area	25.10	18.89	26.44	70.43
- Country areas[65]	17.31	17.98	19.11	54.4

62 Western Power's planning criteria require feeder loads to be kept below 80% of their NCR Normal Cyclic Rating, so that one feeder can be offloaded to four other feeders under emergency conditions. For metropolitan distribution planning standards refer to DMS 4489792. For country distribution planning standards refer to DMS 917435.

63 Typical network solutions to address this need would include augmentation and/or reconfiguration of HV distribution feeders and feeder interconnections.

64 Typical network solutions to address this need would include the installation of voltage regulators, capacitors, HV feeder augmentations, feeder development or feeder load transfers.

65 Rural areas are North Country, South Country, and Goldfields.

7.2.3 Distribution transformer overload upgrade & LV network optimisation

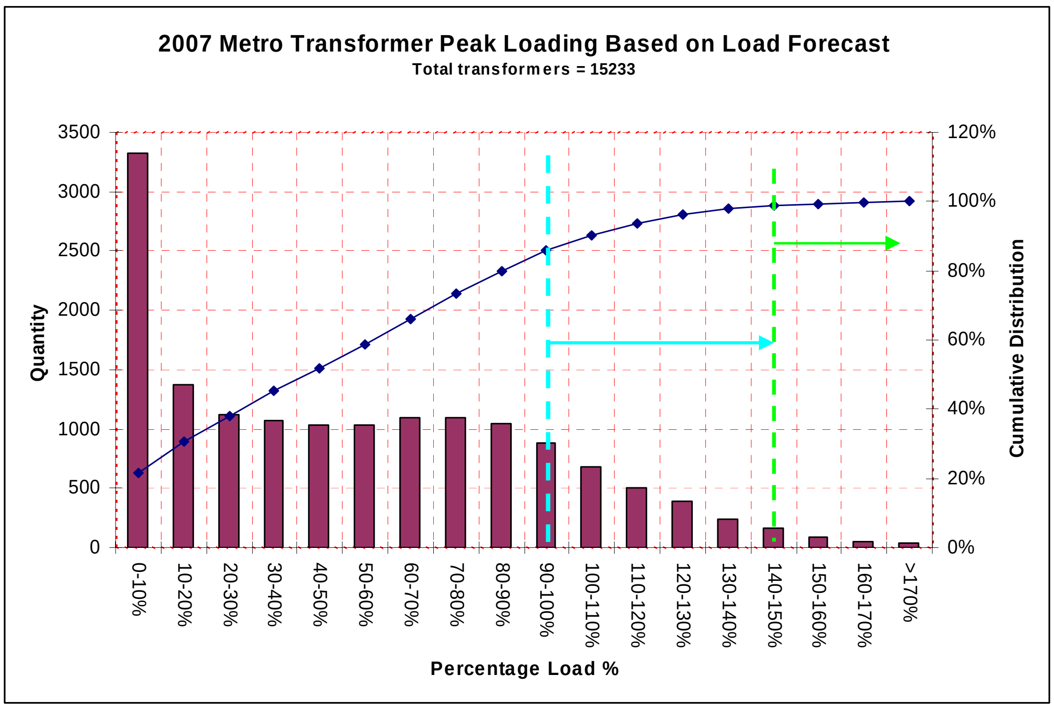
In 2004, Western Power introduced the transformer overload mitigation strategy in response to a significant number of distribution transformers failures. As can be seen from Table 7-4, the historical number of catastrophic transformer failures has been reduced, and is now being maintained at reasonable numbers under this strategy.

Table 7-4 – Transformer overload failures from 2003-2007

Period	No. of transformer overload failures
2003/04	52
2004/05	5
2005/06	2
2006/07	2

As part of the overall management plan under the transformer overload mitigation strategy, Western Power monitors and forecasts the peak load on its distribution transformers. Figure 7-3 shows the current metropolitan region forecast volume of distribution transformers for each peak loading band (as a % of rating)[66].

Figure 7-3 – Distribution transformer peak loading forecast



Overall the distribution transformer overload upgrade and LV network optimisation strategy aims to:

66 Loading is based on the load forecast analysis applied in accordance with the Transformer Overload Upgrade Strategy (DMS 3103072).

- upgrade all distribution transformers in the SWIS that have load forecasts in excess of 140% of installed transformer nameplate rating (shown for the metropolitan region as the region above the green arrow in Figure 7-3). The number of distribution transformers forecast for replacement across the SWIS under this criterion is estimated as 515 over the regulatory period. Sophisticated modeling is conducted on an annual basis to identify particular transformers at risk

- reconfigure LV underground cable networks that are at risk of damage or multiple protective fuse operations due to overload. Across the SWIS, this is estimated to involve the installation of 1.5km of LV underground cable per annum.

Table 7-3 shows the total distribution transformer overload upgrades and LV network optimisation capital works expenditure required over the regulatory period. . It also gives volumes of transformers, LV 240mm^2 underground cables and new 35mm^2 HV cables installed per year to cover new padmount transformers.

Table 7-5 – Distribution transformer overload upgrades & LV network optimisation Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Transformer upgrades ($M)	10.08	9.66	9.65	29.39
Forecast volume (projects)	180	170	165	515

7.3 Customer Access[67]

Distribution customer access includes all capital expenditures associated with the connection of customer loads onto Western Power's distribution network. It does not include expenditures associated with the installation of meters or capacity related network augmentations. The Distribution Headworks Scheme is associated with this expenditure category, and applies to the provision of distribution infrastructure; particularly to customers seeking to connect to the network in rural and regional areas of the SWIS. However this scheme does not apply to transmission infrastructure, to the Central Business District of Perth, the Perth metropolitan area, or the Goldfields.

Figure 7-8 shows the customer access historical and forecast capital expenditure and gifted asset profile from 2005/06 to 2011/12. This forecast is based on the anticipated growth in customer numbers. Employment in Western Australia is expected to grow at 2.6% per annum over the next 4 years. This is in line with recent historical trends, and Western Power's customer growth which is anticipated to remain at approximately 3.2% per annum. It can be seen from Figure 7-8 that it is proposed to increase the customer access capital and gifted assets[68] expenditure from an average of $220M per annum in the 2006/07 to 2008/09 period, to an average of $253M per annum over the regulatory period.

[67] Excludes estimating risk expenditure component

[68] In 2007/8 the policy on customer access Option B work was changed allowing a greater portion of work to be undertaken by external parties, which results in a consequential increase in the value of gifted assets to be received by Western Power.

Figure 7-4 – Customer access capital expenditure ($M)

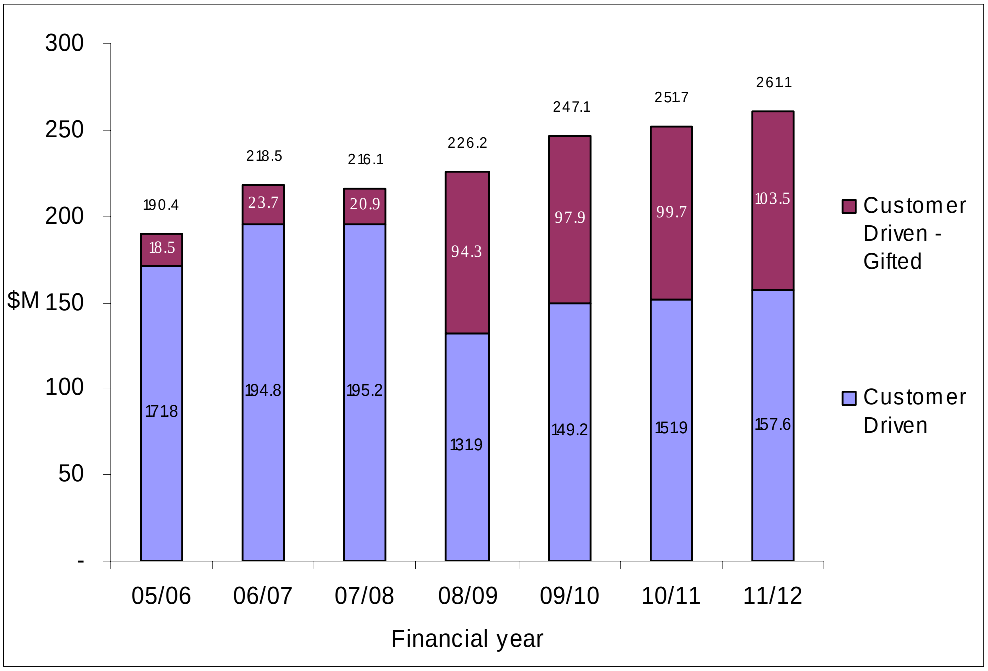


Table 7-6 shows the forecasts of capital expenditure and new customer connections which are expected to increase from 29,273 in 2008/2009 to around 29,810 per year in 2011/2012[69].

Table 7-6 – Customer access expenditure ($M)

Item	09/10	10/11	11/12	Total
Customer access ($M)	149.16	151.93	157.61	458.7
Forecast volume (connections)	29,273	29,542	29,810	88,628

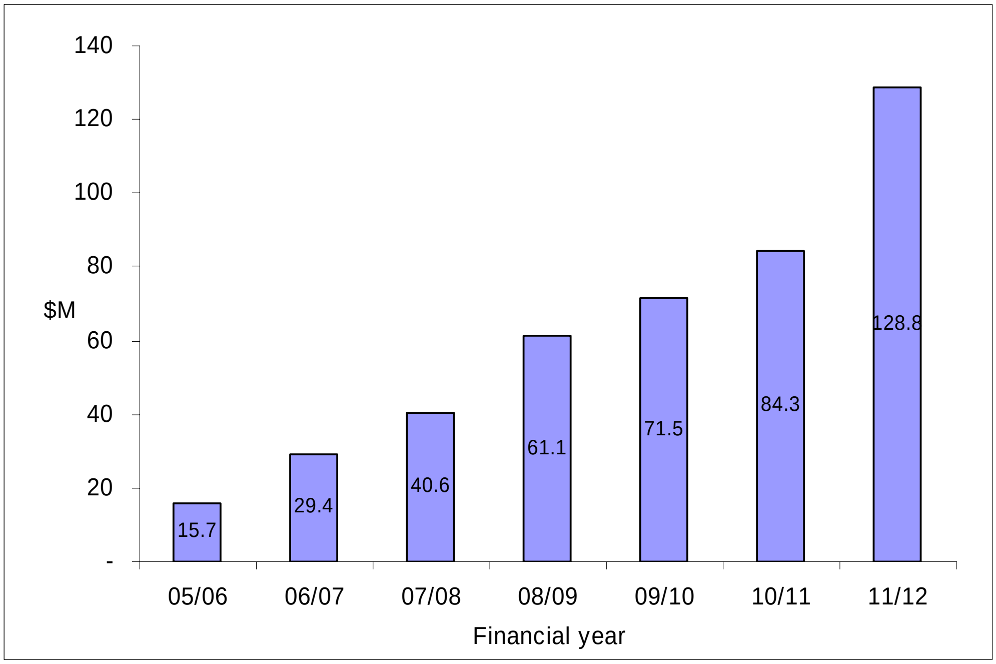
7.4 Asset replacement[70]

Figure 7-5 shows the historical and forecast asset replacement capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure that over the forthcoming regulatory period, it is proposed to increase the asset replacement capital expenditure from an average of $43.7M per annum in the 2006/07 to 2008/09 period, to an average of $95M per annum. This represents an increase of approximately 117%, and is driven by the need to arrest the deterioration in network performance and public safety incidents, and move the network to a sustainable and manageable level of operation.

69 This forecast is based on the linear trend underlying customer numbers growth.

70 Excludes estimating risk expenditure component

Figure 7-5 – Asset replacement capital expenditure ($M)



To determine the magnitude and timing of asset replacement expenditure, Western Power has developed an asset replacement model based on a combination of asset replacement triggers. Specifically, these triggers are the asset class age profile, asset condition information, and assessment of the risks associated with specific distribution assets. This model provides an indication of the level of asset replacement expenditure, and estimates the weighted average remaining life of Western Power's distribution assets. By applying this approach, Western Power has identified, and is targeting, 22 specific asset classes that have been shown to have the greatest impact on network performance and network management.

Whilst this approach provides an initial reference point to identify asset classes that require specific management attention, it is important to note that the forecast asset replacement capital expenditure has been developed using a bottom up-approach. Each major category of asset has been considered, and Western Power's asset management expertise has been applied to asset condition information, failure rates, and other asset information to develop the forecast capital expenditure for the forthcoming regulatory period.

It is also important to note that this management strategy is applied only to non 'run-to-failure' asset classes. Sub-categories in the asset replacement expenditure category include the following assets:

- distribution poles
- distribution carrier (conductor)
- distribution transformer
- substation
- surge arrestors

- drop-out fuse
- switches/disconnectors HV
- rebuilding/reinforcement of Tambellup area feeders
- auto-reclosers
- switches/disconnectors LV
- sectionalisers
- compensators
- vegetation related re-conductoring works
- wildlife proofing (reactive) works.

Specific details of the asset replacement plan associated with each of these sub-categories are outlined in the following subsections.

7.4.1 Distribution pole replacement

Western Power manages over 630,000 wood poles that support the overhead distribution network. While wood poles have a typical life expectancy of approximately 35 years, appropriately loaded good quality poles can last an average of 40 years, and with ground level reinforcement and effective maintenance, they could last up to 60 years on average.

To optimise the management of this critical asset, distribution poles undergo a 4 yearly inspection, and subject to the assessed condition are managed using one of two complementary strategies:

- distribution wood pole reinforcement
- distribution pole replacement.

Pole condition

The integrity of Western Power's pole population has been independently assessed by the Director of Energy Safety to be below that of other Australian distribution networks[71]. While industry pole failure rates are approximately 3.5 poles per 100,000, Western Power's historical unassisted pole failure rate is 34 poles per 100,000, or about 10 times higher than industry average. In addition to this assessment, in 2002 EnergySafety proclaimed regulations that require poles to comply with current industry standards. However, a major proportion of Western Power's wooden distribution poles are more likely to have been built to the standards of the day. A recent serviceability study indicated that one third of the poles in the SWIS network may have a design load greater than the pole capacity as defined by current industry standards.

[71] EnergySafety (Department of Consumer & Employment Protection), 2006, *Western Power's Wood Pole Management Systems: Regulatory Compliance Assessment Report*

Western Power has assessed the risk of unassisted wood pole failures as extremely high.

To address this situation, Western Power has made a focused effort to reduce some of the condemned pole backlog, and is seeking to enhance both its pole replacement and pole reinforcement strategies (see below). In addition, a new non-invasive pole testing method is being introduced to enhance pole management over the longer term, and Western Power is taking steps to improve the pole management system by reviewing:

- design standards for compliance with HB C(b)1
- construction standards and compliance audits
- pole procurement process including procurement specifications
- pole inspection process using external consultants, alternative testing methods and pole serviceability criteria, and
- processes for verifying unassisted pole failures.

Western Power is targeting an industry best practice standard through the implementation of these combined strategies.

Distribution pole replacement

Western Power assesses wooden pole serviceability through an inspection-based condition monitoring process as is undertaken by all other Australian utilities. Following inspection, poles identified as unserviceable (and not suitable for reinforcement) are replaced in order to maintain the safety and reliability of the network.

As discussed above, one element of this strategy involves the introduction of a new non invasive pole testing method and improving the reliability of the existing test. The new test method is widely used in the UK, New Zealand and in parts of the US. While the annual condemnation rate using the standard drill test methods varies from 2 to 4%, initial trial results indicate that under the new test method an annual condemnation rate of approximately 5% of the poles inspected each year (or 7,500 poles p.a.) can be expected over the next 5 years.

Therefore, in order to address Western Power's currently high pole failure rate, this pole replacement strategy aims to deliver an average pole replacement of 1.2% of the pole population per annum over the regulatory period. That is, the replacement of 22,550 poles during the next regulatory period at an average rate of 7,500 poles per annum. Western Power believes that this strategy combined with the other improvements targeted will achieve an overall performance of 15 or less failed poles per 100,000 poles[72] over the period.

Table 7-7 shows the forecast pole replacement volumes and expected capital expenditure required for the successful implementation of this strategy. It should be noted that poles are also being replaced under other strategies/projects (e.g. bushfire mitigation strategies, RPIP, SUPP), and these poles are excluded from these estimates.

72 Note that the industry standard pole failure rate is approximately 3.5 poles per 100,000 poles.

Table 7-7 – Distribution pole replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Pole replacement ($M)	39.57	45.09	61.92	146.58
Forecast volume (poles)	6,200	7,000	9,350	22,550

Distribution Wood Pole Reinforcement

Western Power's policy is to extend the life of wood poles by reinforcing where inspection shows that the pole reinforcement is required, and where the pole is suitable for reinforcement. Under these conditions, Western Power is of the view that this is a far more cost effective option than other strategies to prolong pole life.

Historically Western Power has reinforced its pole population based on condition assessment. However, the historical unassisted pole failure rate (as discussed above) is higher than industry average and suggests that the existing inspection method is not fully identifying unserviceable poles. As part of the overall strategy to address the currently high pole failure rate, Western Power has reviewed its serviceability criteria, and this has resulted in an increase in the number of poles requiring reinforcement. Western Power is of the view that this approach is essential to manage the current situation, and move progressively towards an industry average failure rate.

With an average reinforcement rate of 1.5%, this strategy aims to deliver reinforcement to 28,000 poles during the next regulatory period at an average rate of 9,300 poles per annum. Western Power believes that this strategy, combined with other improvement initiatives, will achieve an overall performance of 10 or less failed poles per 100,000 poles over this period.

Table 7-8 shows the forecast pole reinforcement volumes and expected capital expenditure required for the successful implementation of this strategy. It should be noted that poles are also being reinforced under other strategies/projects (e.g. 40 worst feeders, targeted reinforcement, transformer pole reinforcement, RPIP), and these poles are excluded from these estimates.

Table 7-8 – Distribution pole reinforcement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Pole reinforcement ($M)	9.75	12.30	12.64	34.69
Forecast volume (poles)	8,000	10,000	10,000	28,000

7.4.2 Distribution carrier replacement

Western Power's SWIS distribution network has approximately 74,500km of overhead conductors and 15,700km of underground cables[73]. The distribution carrier replacement strategy is aimed at maintaining this network in a safe and reliable condition by replacing sub-standard carriers and taps.

[73] Approx. lengths are: high voltage overhead - 64,000km, low voltage overhead - 10,500km, high voltage underground - 5,000km, low voltage underground 10,700km.

Western Power has been developing strategies to monitor the condition of carriers through planned inspections every 4 years and targeted inspections in areas of high failure rates or increased risk of failure. This strategy is aimed at identifying sub-standard carriers and taps before failure, and replacing them based on assessment of their specific condition[74]. Carriers and taps can fail due to corrosion, high fault currents, environmental influences, and for a range of other reasons. Such failures impact adversely on supply reliability, incur a higher cost to repair after failure, and can pose a serious safety risk. Western Power has assessed this risk as extremely high.

Typically, the life of overhead conductors is 55 years, while underground cables have a life of approximately 65 years. Most carriers that form part of the SWIS overhead distribution network are over 30 years old[75]. A recent report, following a study commissioned by Western Power using external consultants (Maunsel) identified corrosion as a significant issue on particular feeders. The report (compiled mainly as a desktop study), estimated that about 12,000km of carrier are at risk. Additionally, in recent years the wires down risk has been increasing, with a notable trend in these incidents as shown in Figure 7-6.

Western Power believes that it is necessary to achieve an overall performance of fewer than 100 unassisted wires down incidents per annum, and a conductor fault count to length ratio of 1:50km. Based on available carrier data (field reports and desk top studies), as well as previous replacement history, it is estimated that the distribution carrier replacement strategy will need to replace 300km of overhead conductor, 60km of underground cable, and 3000km of line taps to achieve these targets. This will require a minimum average expenditure of $12M per annum over the next regulatory period, with the replacement program expanding and continuing over a 10 year period. This compares to a historical average expenditure of $2.5M per annum for the past 3 years. It should be noted that current expenditures were less than required due to resource and financial constraints.

74 Refer to DMS 3429420 – Distribution Overhead Conductor Management Plan.

75 It should be noted that while the carrier replacement strategy is based on condition assessment, rather than a blanket replacement based on age, Western Power does consider the type and location of carriers as a means of prioritising areas requiring management action.

Figure 7-6 – Unassisted wires down incidents per annum

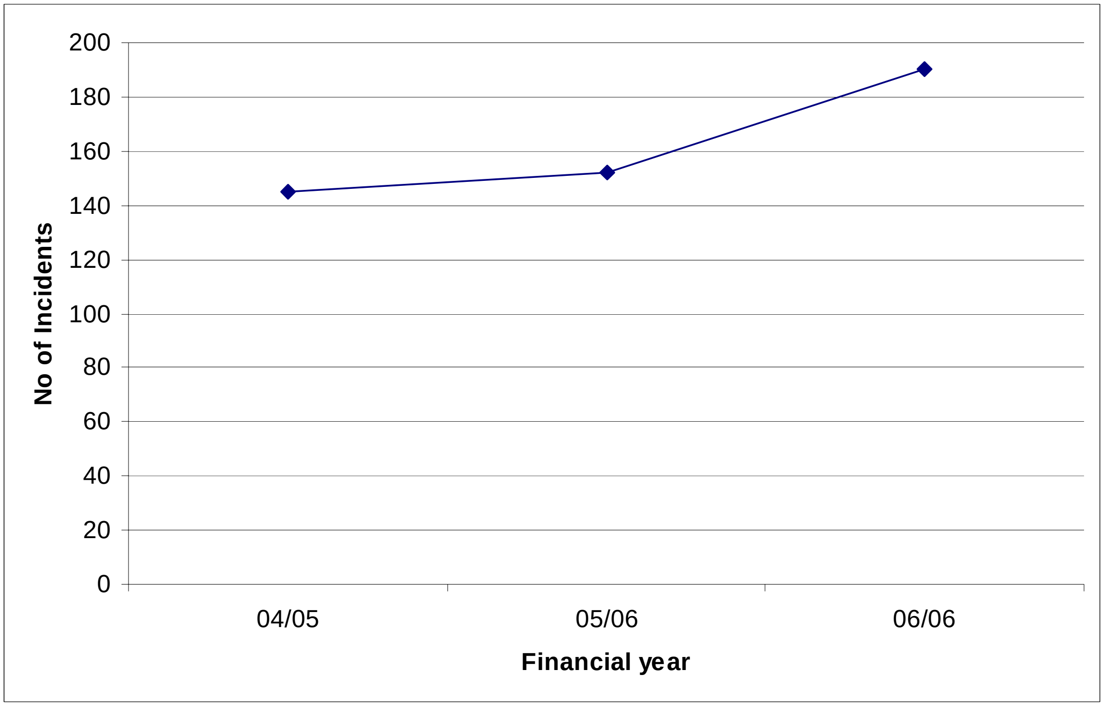


Table 7-9 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. It should be noted that when replacing carriers, an equivalent modern replacement approach is used, with allowance for known load growth and changing fault level conditions. In arriving at these estimates, carriers being replaced under other strategies/projects have been excluded (e.g. 40 worst feeders, bushfire mitigation, long bay, SUPP, RPIP, etc).

Table 7-9 – Distribution carrier replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Carrier replacement ($M)	8.01	8.08	20.77	36.86
Volume replaced				
- Overhead (km)	20	20	50	90
- Underground (km)	4	4	10	18
- Line taps (per km)	200	200	500	900

7.4.3 Distribution transformer replacement

In general, Western Power's policy is to run distribution transformers to failure. This strategy involves the replacement or refurbishment of distribution transformers that fail in service, as well as replacement or refurbishment of transformers based on condition assessment.

In the SWIS network there are approximately 60,000 distribution transformers. The majority of these (over 50,000) are smaller pole mounted transformers. Pole mounted transformers are inspected every four years under the line inspection program, and ground mounted transformers are inspected annually. While historically about 650 of these failed transformers are repaired and put back into service, approximately 150 new transformers are required each year for replacement.

This strategy aims to deliver the replacement of 255 distribution transformers during the regulatory period, with the program continuing over a five year period. Western Power believes that this will achieve an overall performance of less than 0.1% of units failed before their economic life, and an average of no more that one transformer rated greater than 330kVA failure per year.

Table 7-10 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. As all new projects in the metro area will be underground developments, more ground mounted type transformers will be required, while some pole mounted transformers will be removed from the network. Hence for the purposes of forecasting the required capital expenditure, it has been assumed that of the 255 transformers to be replaced, 75% will be three phase ground mounted type with the balance pole mounted.

In arriving at these estimates, transformers being replaced under other strategies/projects have been excluded (e.g. power quality compliance, SUPP, RPIP, etc).

Table 7-10 – Distribution transformer replacement Capex forecast ($M)

	09/10	10/11	11/12	Total
Forecast expenditures ($M)	2.40	3.22	8.29	13.91
Forecast volume	45	60	150	255

7.4.4 Drop Out Fuse replacement

Western Power’s asset management plan does not require monitoring the condition of Drop Out Fuses **(DOFs)**, other than after fuse operation, or visually once every four years under the bundled pole inspection program. Additionally, fuse pole base inspections are carried out annually in bushfire risk areas.

In the SWIS network, there are close to 31,000 distribution DOFs. About 10,000 of these DOFs are unsuitable for service, with 13% of all unplanned interruptions in the SWIS occurring due to DOF fuse operations.

Consistent with Australian practice, expulsion type DOFs are being progressively phased out, as they are no longer supported by the manufacturer and replacement parts cannot be obtained.

Most DOF related problems are due to corroding barrels and barrel blockage due to years of operation. They have in the past been replaced after operation but this process has been ineffective due to the barrel types being non-standard. To be effective the entire unit including the base must be replaced in most instances. Moreover, some of the DOFs are not sufficiently fault rated. This activity involves identifying those DOFs that are unsuitable for service, and replacing them after inspection. The specific units being targeted have a history of false operation and explosive failure under certain conditions.

Western Power has assessed the risk of DOF mal-operation as high due to the safety and supply reliability implications.

The replacement strategy aims to progressively reduce sub standard DOFs on the network by replacement

Table 7-11 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on estimates of DOF types determined from field information. It is also important to note that in arriving at these estimates, DOFs that are being replaced under other strategies/projects have been excluded (i.e. Fire Safe Fuses).

Table 7-11 – Drop out fuse replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	0.00	0.60	2.46	3.06
Forecast volume (3ph sets)	0	200	800	1,000

7.4.5 Surge Arrestors replacement

Western Power monitors the condition of surge arrestors once every four years under the bundled pole inspection program. While unserviceable units are identified and replaced through this condition assessment process, records indicate that there are unserviceable surge arrestors within the distribution network.

The SWIS contains approximately 18,000 distribution surge arrestors, of which about 5,500 units are porcelain arrestors, or unserviceable polymeric surge arrestors. The surge arrestor replacement strategy is intended to identify and replace all porcelain and polymeric surge arrestors that are identified as being unsuitable for service, as they have a history of false operation, and explosive failure under certain conditions[76]. In addition, as the typical life of surge arrestors is around 35 years, other units will need to be replaced to maintain the serviceability of the surge arrestor population.

Western Power has assessed the risk of surge arrestor explosions as a medium risk; as such incidents can have safety and reliability implications.

This strategy aims to deliver the replacement of 900 surge arrestors during the regulatory period with the program continuing over a 10 year period. Western Power believes that this will achieve a performance of less than 0.1% of surge arrestors requiring replacement within a 12 month period before end of economic life.

Table 7-12 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. In arriving at these estimates, surge arrestors being replaced under other strategies/projects have been excluded (e.g. lightning mitigation in North Country).

Table 7-12 – Surge arrestors replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	0	1.27	2.62	3.89
Forecast volume (3ph sets)	0	300	600	900

[76] Refer to Asset Mission for Surge Arrestors in DMS 611710.

7.4.6 Street light luminaires replacement

The strategy provides for the replacement of luminaires that are no longer serviceable or economic to refurbish. The luminaires to be replaced are single insulated and do not meet the current standards that require double insulated wiring. Additionally, the new luminaires will enable the use of energy efficient globes, improved illumination levels and reduced spill and glare.

Luminaries to be replaced under this strategy will include those luminaires that have reached the end of their serviceable life, where the condition is assessed as poor, or where the luminaires does not comply with current standards.

Table 7-13 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on a luminaires age profile and an estimated rate of degradation to determine the expected number of luminaires that are likely to require replacement over the regulatory period with an average replacement age of 20 yrs. As this is a new strategy there is no historical data available.

Table 7-13 – Street light luminaires replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	0	0.59	2.41	3.00
Forecast volume	0	1,000	4,000	5,000

7.4.7 Other minor asset replacement strategies

Western Power has a number of minor strategies that are being implemented to replace assets that are no longer serviceable. Table 7-14 shows the forecast work volumes and expected capital expenditure required for the successful implementation of these minor strategies. Reference should also be made to the DMS numbers noted against each strategy in the table for further supporting information and other references.

Table 7-14 – Other minor asset replacement strategies Capex forecast ($M)[77]

Strategy	Key driver	Unit	09/10	10/11	11/12	Total
Distribution substation replacement (DMS 4870049)	Unserviceable Asset Reliability	$M	1.44	1.46	2.24	5.14
		Volume	10	10	15	35
Switches/Disconnectors HV replacement (DMS 4285674)	Unserviceable Asset Reliability	$M	2.97	2.99	3.08	9.04
		Volume	26	26	26	78
Reinforcement of Tambellup area feeders (DMS 4328152)	Unserviceable Asset Reliability	$M	0.48	0.48	2.99	3.95
		Volume	20km	20km	40km	80km
Street light metal pole replacement (DMS 4884749)	Unserviceable Asset Reliability	$M	0	0.33	1.34	1.67
		Volume	0 SLP	100 SLP	400 SLP	500 SLP
Cable box replacement (DMS 4518325)	Safety Reliability	$M	2.39	2.41	2.48	7.28
		Volume	100 Boxes	100 Boxes	100 Boxes	100 Boxes
Reclosers replacement (DMS 4285749)	Unserviceable Asset Reliability	$M	1.70	1.71	1.76	5.17
		Volume	27	27	27	81
Switches/Disconnectors LV replacement (DMS 4285698)	Unserviceable Asset Reliability	$M	1.48	1.50	1.54	4.52
		Volume	50 GM 50 PM	50 GM 50 PM	50 GM 50 PM	150 GM 150 PM
Vegetation related re-conductoring works (DMS 4470167)	Fire risk Community concerns Safety Reliability	$M	1.31	1.32	1.36	3.99
		Volume	7.4km CC or 5km UG	7.4km CC or 5km UG	7.4km CC or 5 kmUG	22km CC or 15km UG
Sectionaliser replacement (DMS 4869816)	Unserviceable Asset Reliability	$M	0.00	0.91	0.93	1.84
		Volume	10	10	15	35
Total (M)			**11.77**	**13.11**	**17.72**	**42.6**

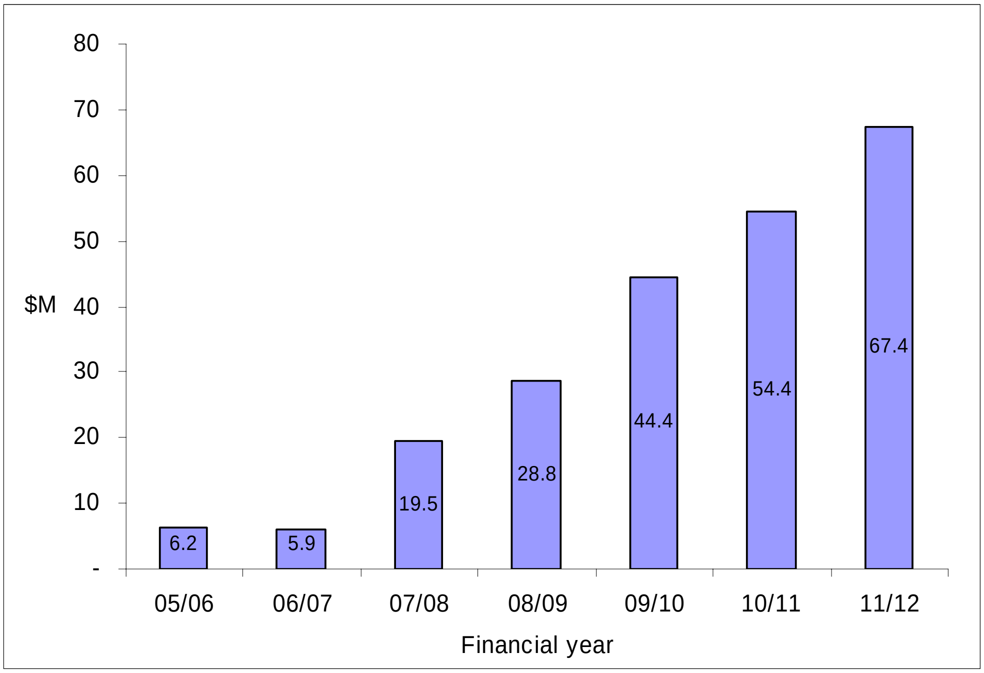
77 GM – Ground Mounted, PM – Pole Mounted, CC – Covered Conductor, UG – Underground cable, SLP – Street Light Pole.

7.5 Reliability[78]

Figure 7-7 shows the historical and forecast reliability driven capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the forthcoming regulatory period, it is proposed to increase the reliability capacity capital expenditure from an average of $18M per annum in the 2006/07 to 2008/09 period, to an average of $55M per annum over the regulatory period. This represents an increase of approximately 306%.

Specific details of the reliability driven strategies are outlined in the following subsections.

Figure 7-7 – Reliability capital expenditure



7.5.1 Distribution automation deployment - reclosers (3ph) & LBS (3ph)

The objective of this strategy is to reduce the number of customers affected by supply interruptions, and significantly improve supply restoration time through the use of remote controlled automation devices. These devices will enable remote isolation of faulted sections of the network, and restoration of supply to the un-faulted sections. Through the optimum deployment of 3-phase tele-metered reclosers and load-break switches across the SWIS, Western Power can move towards achievement of the regulatory SWIS SAIDI target, and improve the businesses network management capability.

It has been determined that through this strategy improvements in the SWIS SAIDI of 13.8 minutes can be achieved. This represents a cost-benefit of $0.93M per SWIS SAIDI minute. Additional benefits achieved through this strategy include improved asset data, improved

[78] Excludes estimating risk expenditure component

public and staff safety, and this strategy is also a key enabler of sequence switching technology that can achieve further significant reliability improvements.

Table 15 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. Previous history of distribution automation works has been taken into account in developing this forecast.

Table 7-15 – Distribution automation deployment - reclosers (3ph) & LBS (3ph) Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	5.67	8.62	7.44	21.73
Forecast (volume)				
- reclosers	32	47	40	119
- load break switches	55	84	70	209

7.5.2 Worst section targeted reliability reinforcement

The worst section targeted reliability reinforcement strategy focuses on feeders that contribute the most customers interrupted minutes (CIM) to the SWIS network, as well as the replacement of substandard equipment that pose a safety risk. This strategy involves reinforcement of the first section of HV overhead distribution feeders across the SWIS, which focuses on identifying and rectifying sub-standard constructions and/or defective components in the feeder backbone. This work includes, but is not limited to, replacement or reinforcement of poles, cross arm and insulator replacement, conductor replacement/upgrading, surge arrester installation and animal proofing.

Feeder and recloser trips contribute 76% of SWIS SAIDI minutes; the targeted reliability reinforcement strategy is expected to result in a reduction of 1.64 SWIS SAIDI minutes per annum over the regulatory period[79]. Based on the proposed expenditure and saving in SWIS SAIDI minutes, this is equivalent to a cost-benefit of $9.06M per SWIS SAIDI minute saved[80].

Table 7-16 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. It is also important to note that in arriving at these estimates, works associated with other strategies/projects have been excluded (e.g. RPIP, SUPP, feeder rebuild).

Table 7-16 – Targeted reliability reinforcement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	8.17	8.25	11.30	27.72
Forecast volume (sections)	15	15	20	50

79 Refer to DMS 4598713 for SWIS SAIDI calculations.

80 Note that the Energy Networks Association's Reliability and Power Quality Working Group, collated data from around Australia and found the utilities are able to justify expenditures of between $2M to $7M per SAIDI minute improvement. See also DMS 4464295.

7.5.3 Reliability reconductoring for LBS installation

This strategy involves reconductoring at open points where load break switches will be installed. This will provide an improved load transfer capacity under network fault conditions and subsequently enable implementation of automated switching devices.

Note that the reliability reconductoring strategy is a supporting strategy only, and therefore there are no directly attributable SAIDI savings.

Table 7-17 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. It is important to note that in arriving at these estimates, works associated with other strategies/projects have been excluded (e.g. RPIP, SUPP, feeder rebuild, etc).

Table 7-17 – Reliability reconductoring for LBS installation Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	11.86	10.80	3.76	26.42
Forecast volume (km)	46	41	14	101

7.5.4 North Country feeder section refurbishment

Feeder trips contribute 47% of SWIS SAIDI minutes, and much of this is related to the poor condition of aging infrastructure which in some cases is at least 40 years old and beyond its economic life. Most faults on the targeted feeders are caused by pole top equipment failure (e.g. ties, crossarms, insulators), corroded or clashing conductors, pole base failures (wood rot), or lightning. The North Country feeder section refurbishment strategy targets the first section of poor performing HV distribution feeders, and other under-rated feeder sections, for rebuilding to address these issues.

Western Power has estimated that this strategy will result in a total SWIS SAIDI saving of 0.19minute per annum.

The targeted feeders have been identified from fault data with six of the targeted feeders included on the forty worst feeder reliability list for 2005/06 and 2006/07. Other rebuilds have been identified based on condition data, known under-rated conductor and local knowledge. A detailed work plan has been developed and is summarised in Table 7-18.

Table 7-18 – North Country feeder rebuild works plan

Feeder	Area Covered	Length (Km's)	Pole Age (Yrs)	Year
TS 611 Morawa	Morawa, Perenjori, Canna Rural Community	44	39	09/10
MOR 613 Dandaragan	Dandaragan, Cataby, Badgingarra, Rural Community	7	37	10/11
NOR 540 York	York Town	0.1	46	10/11
MOR 603 New Norcia	New Norcia, Calingari, Rural Community	17	38	10/11
MOR 607 Wongan Hills Sth	Cadoux, Ejanding, Kalannie, Goodlands, Rural Community	49	39	11/12
MOR 610 Dalwallinu	Dalwallinu, Pithara, Rural Community	58	37	11/12

Table 7-19 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast has been built up from estimates for each of the individual feeder rebuild projects. It is also important to note that in arriving at these estimates, works associated with other strategies/projects have been excluded (e.g. RPIP, SUPP, feeder rebuild).

Table 7-19 – North Country feeder section refurbishment Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	8.52	5.87	20.26	34.65
Forecast volumes - total route length (km)	44	29	102	175

7.5.5 Automated Circuit Breaker RMU deployment

This strategy involves the replacement of existing underground switchgear with Circuit-Breaker Ring Main Units (CB-RMU's) in strategic locations to improve the supply reliability of underground and hybrid networks. CB-RMU's are capable of remote control, monitoring, isolation, and sequence switching which will allow Western Power to minimise the number of customers affected by a fault, as well as reduce restoration times.

It has been estimated that this strategy will result in a reduction of approximately 0.51 SWIS SAIDI minutes. This represents a cost benefit of $6.48M per SWIS SAIDI minute saved[81]. The installation of these units is also a key enabler of sequence switching which will support further improvements in supply reliability, and will contribution to the provision of improved network management data.

[81] Note that the Energy Networks Association's Reliability and Power Quality Working Group, collated data from around Australia and found the utilities are able to justify expenditures of between $2M to $7M per SAIDI minute improvement. See also DMS 4464295.

Table 7-20 shows the forecast work volumes and expected capital expenditure required for the successful implementation of this strategy. No previous expenditure history exists as this is a newly developed strategy for a new asset type.

Table 7-20 – Fully Automated RMU deployment Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	0	3.71	7.62	11.33
Forecast (volume)	0	30	60	90

7.5.6 North Country pole reinforcement

Pole reinforcement is a proven and cost-effective method of extending pole life and returning poles to a serviceable condition. While almost 52% of North Country HV poles are reinforced, available data shows that 90% of unassisted pole failures during 2001 to 2003 were unreinforced poles[82]. In particular, pole failures on the feeder backbone contributes significantly to customer minutes interrupted, and even though the number of customers affected may be small, pole failures at the extremities of the network are difficult to repair due to the large travel distances and limited resources in these areas.

This strategy specifically targets reinforcement of strategic poles whose failure would have a significant negative impact on the reliability of the network. Poles selected for reinforcement are on fifteen North Country Feeders with several of these feeders exhibiting above average SAIDI performance[83].

Table 7-21 shows the forecast reinforcement volumes and expected capital expenditure required for the successful implementation of this strategy. Previous replacement history has been taken into account developing this forecast, with quantities based on field information. It should also be noted that North Country poles targeted for reinforcement under other pole reinforcement strategies have been excluded from these estimates (e.g. transformer pole reinforcement, unserviceable pole reinforcement).

Table 7-21 – North Country pole reinforcement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	1.60	3.72	3.56	8.88
Forecast volume	950	2,200	2,050	5,200

It should be noted that the unit cost for this strategy is higher than that for the general wood pole reinforcement strategy (see section 7.4.1). The reason for this is that the cost of reinforcing poles in North Country is higher due to the remote locations and significant distances travelled to do the work. The unit cost for general wood pole reinforcement is averaged across the SWIS, which includes metro, north and south country.

82 Refer DMS 4470328.

83 Refer DMS 4471592.

7.5.7 Other minor reliability strategies

Western Power has a number of minor strategies that are being implemented to improve the supply reliability performance of the distribution network and move Western Power toward compliance with the reliability performance targets.

Table 7-22 shows the forecast work volumes and expected capital expenditure required for the successful implementation of these strategies. Reference should also be made to the DMS numbers noted against each strategy in the table for further supporting information and other references.

Table 7-22 – Other minor reliability strategies Capex forecast ($M)[84]

Strategy	Unit	09/10	10/11	11/12	Total
South country feeder section refurbishment (DMS 4339917)	$M	1.97	4.50	4.23	10.7
	Volume	10km	23km	21km	54km
Pole top switch (PTS) installation (DMS 4900180)	$M	0.48	0.48	0.50	1.46
	Volume	15 PTS	15 PTS	15 PTS	45 PTS
Telemetry retro-fit (DMS 4470508)	$M	1.20	1.75	1.80	4.75
	Volume	37	55	55	147
1st section undergrounding (DMS 4244287)	$M	1.91	1.75	1.20	4.86
	Volume	4.7km	4.2km	2.6km	11.5km
Wildlife proofing on the distribution network (DMS 4276419)	$M	1.58	1.79	1.20	4.57
	Volume	520	600	409	1,529
Overhead fault-indicator deployment (DMS 4429807)	$M	0.00	0.92	0.94	1.86
	Volume	0	60	60	120
Underground fault-indicator deployment (DMS 4422617)	$M	0.61	0.61	1.20	2.42
	Volume	25	25	50	100
Targeted DOF 1 phase recloser replacement (DMS 4413300)	$M	0.61	0.62	0.84	2.07
	Volume	15	15	20	50
Reliability improvement pilot projects (DMS 4897807)	$M	0.00	0.76	0.85	1.61
	Volume[85]	0	175	225	400 units
Lightning mitigation (DMS 4280538)	$M	0.20	0.20	0.21	0.61
	Volume[86]	83	83	83	249 sites
DA pilots of new equipment (DMS 4477051)	$M	0.00	0.00	0.46	0.46
	Volume	-	-	3	3

84 ZS – Zone Substation, PTS – Pole Top Switch. Where no volume is given, then the units are in units of plant for the respective equipment involved in the strategy.

85 Units are Dropout Surge Diverters, Epoxy Cross-arms, Vibration Monitoring and Mitigation.

86 Units are 3 phase arrestors and 1 phase arrestors.

Strategy	Unit	09/10	10/11	11/12	Total
Fault indicator location prediction system (DMS 4878232)	$M	0.03	0.03	0.08	0.14
	Volume	-	-	-	-
Targeted fuse investigations & replacement (Pilot)	$M	0.00	0.02	0.02	0.04
	Volume	0	3	3	6
Total ($M)		8.59	13.43	13.53	35.55

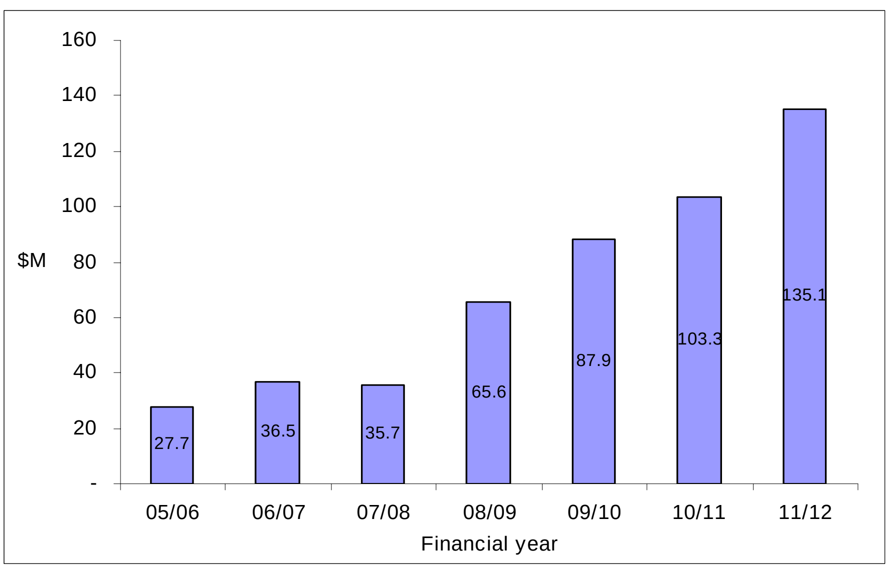
7.6 Compliance[87]

This program of work aims to meet the safety, environmental and statutory compliance obligations of Western Power, particularly in regard to public safety, environmental management, and power quality (PQ) codes.

Figure 7-8 shows the historical and forecast safety, environmental and statutory capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the forthcoming regulatory period, it is proposed to increase the distribution capacity capital expenditure from an average of $46M per annum in the 2006/07 to 2008/09 period, to an average of $109M per annum over the regulatory period. This represents an increase of approximately 237%.

The magnitude and timing of safety, environmental and statutory capital expenditure is driven by the need for Western Power to comply with statutes, codes, and regulations. Specific details of the safety, environmental and statutory compliance strategies are outlined in the following subsections.

Figure 7-8 – Safety, environment and statutory capital expenditure



87 Excludes estimating risk expenditure component

7.6.1 Replacement of overhead customer service connections

This strategy involves the replacement of all overhead PVC customer service connections and supporting equipment in accordance with current Western Power practice and regulatory requirements to mitigate safety hazards. This is an ongoing program of works which commenced in 2003/04 following several fatalities involving PVC customer service connections.

This strategy aims to deliver the replacement of 83,000 out of a total population of 300,000 service connections, at an average rate of 27,700 services per annum, and will lead to a reduction in the number of asset related shock incidents by the end of the regulatory period.

Table 7-23 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy.

Table 7-23 – Replacement of overhead customer service connections Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	17.38	15.67	19.33	52.38
Forecast volume (connections)	28,000	25,000	30,000	83,000

7.6.2 HV conductor clashing

Following a fire at Tenterden in early 2007 involving the death of two people, the Director of Energy Safety issued an order against Western Power requiring the installation of a means to prevent HV overhead conductor clashing. While this order applies specifically to the South Coastal and Great Southern regions, it also requires that Western Power prepare strategies to mitigate the risk across the SWIS. A long-term works program has been initiated to address this requirement and mitigate the risk of conductor clashing.

Western Power has identified 50,000 bays that are at risk based on the bay length and configuration (e.g. type of construction, line deviation). The major works will include installing intermediate poles and longer cross-arms (as required) in long bays[88]. This strategy aims to deliver a total of 7,250 solutions over the regulatory period.

Table 7-24 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy.

Table 7-24 – HV conductor clashing Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	8.45	10.66	12.05	31.16
Forecast volume (solutions)	2,000	2,500	2,750	7,250

88 “Long bays” are defined as 3 phase, straight bays in excess of 155m, and running disk angle (RDA) bays in excess of 105m for all conductor types

7.6.3 Bushfire mitigation wires down

In recent years there have been several incidents where the failure of overhead distribution conductors has caused fires that resulted in property damage and/or serious injury or death. Investigation of these incidents has shown that the condition of pole top hardware, conductor corrosion, bird-caging, as well as cross arm and insulator failures are of particular concern.

This strategy will specifically target high and extreme bushfire risk areas, and will replace overhead distribution conductors and associated pole top hardware assessed by the overhead line inspection program to be in poor condition. Western Power's asset management plan requires monitoring the condition of overhead lines every four years.

Western Power has assessed the risk of failure of overhead distribution conductors as extremely high as such incidents can have significant safety and supply reliability implications.

This strategy aims to deliver a total of 104km of overhead, 280km of running earth wire, and 14km of underground mains over the regulatory period. Table 7-25 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy.

Table 7-25 – Bushfire mitigation wires down Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	11.09	13.14	20.26	44.49
Forecast volumes (km)				
- replace with overhead	24	32	48	104
- replace earth wire	80	80	120	280
- replace with underground	4	4	6	14

7.6.4 Fire safe fuses

In the SWIS rural distribution network there are approximately 31,000 DOFs, with about 18,000 of these located in extreme or high fire risk areas. While pole base clearing mitigates the impact, explosive failure of expulsion type fuses (particularly those units that are unsuitable for service) has caused major bushfires.

This strategy involves identifying DOFs in high and extreme fire zones, and replacing them with boric acid fuses which are capable of arc free operation. The specific units being targeted have a history of false operation and explosive failure under certain conditions. In addition, as the typical life expectancy of a DOF is approximately 35 years[89], further units will require replacement as they become unsuitable for service during the regulatory period.

Western Power has assessed the risk of DOF mal-operation as high due to the safety and supply reliability implications.

In order to remove all the defective DOFs from the network and maintain a serviceable DOF population, this strategy aims to deliver the replacement of 2,054 3-phase DOFs and 725

89 It is noted that some network operators replace fuse barrels after ten years service.

1-phase DOFs during the regulatory period with all defective DOFs replaced over a 10-year period.

Table 7-26 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on estimates of DOF types determined from field information. It is also important to note that in arriving at these estimates, DOFs that are being replaced under other strategies/projects have been excluded (e.g. Drop Out Fuse replacement, Targeted DOF to Single Phase Recloser Replacement, Pole top replacement in high fire risk areas).

Table 7-26 – Fire safe fuses Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	2.22	4.48	7.67	14.37
Forecast volume				
- 3ph sets	324	648	1,082	2,054
- 1 ph units	75	150	500	725

7.6.5 PQ compliance reinforcement

This strategy provides remedial works to maintain network power quality within statutory limits. The primary drivers for this expenditure are customer complaints regarding power quality (PQ) issues[90], and compliance with the requirements of the Technical Rules. Western Power also has obligations to monitor the network PQ performance[91], and will be installing PQ monitoring equipment to ensure that network performance can be measured on a sample basis to demonstrate compliance of the distribution network.

Table 7-26 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on the number of customer complaints forecast from historical trends. It is also important to note that in arriving at these estimates, the works to be undertaken under other strategies/projects have been excluded from these estimates (e.g. Distribution Transformer Overload Upgrades & LV Network Optimisation, SUPP).

Table 7-27 – PQ compliance reinforcement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	11.85	11.96	12.09	35.90
Forecast volumes:				
- No. LV circuits reinforced	156	156	153	465
- New HV conductors (km)	1.56	1.56	1.56	4.68
- LV underground cable (km)	23.4	23.4	22.9	69.7
- No. distribution transformers	16	16	15	47

90 Power quality includes such issues as voltage fluctuations, voltage flicker, and harmonics.

91 Compliance requirements fall under the *Electricity Act 1945* and *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

7.6.6 Pole top replacement in high fire risk areas

Following several safety incidents relating to the condition of pole tops on the distribution network, Western Power has adopted a strategy for high fire risk areas the seeks to replace

pole tops that do not comply to C(b)1[92]. Specifically, overhead line inspection data will be used to target specific poles in high fire risk areas where the condition of cross-arms, insulators and conductor ties is poor. This strategy is part of a set of complementary strategies that Western Power has adopted to maintain overhead assets and minimise the likelihood of network initiated fires.

Table 7-28 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on estimates of the number of poles in high fire risk areas. It is also important to note that in arriving at these estimates, that pole tops that are being replaced under other strategies/projects have been excluded (e.g. targeted reliability improvement strategies, RPIP, Bush Fire Management Plan[93] **(BFMP)** Wires Down, and BFMP Long Bay).

Table 7-28 – Pole top replacement in high fire risk areas Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	4.26	8.60	13.25	26.11
Forecast volumes				
- 3 phase poles	800	1,600	2,400	4,800
- 1 phase poles	800	1,600	2,400	4,800

7.6.7 Pole top switches replacement

This is an ongoing program to replace pole top switch earthing mats due to the occurrence of a near fatality incident. While temporary measures have been taken to safeguard staff, continuation of this work is needed to complete implementation of a permanent solution. The rectification of this safety issue is clearly required under the provisions of the *Electricity (Supply Standards & System Safety) Regulation 2001*.

Table 7-29 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on the replacement of pole top switch models with limited capabilities, which are unsuitable for the efficient operation of the network.

92 Western Power's overhead lines must comply with *Guidelines for the Design, Construction and Maintenance of Overhead Lines* (HB C(b)1) as required by the *Electricity (Supply Standards & System Safety) Regulations*.

93 DMS 5014386

Table 7-29 – Pole top switches replacement Capex forecast ($M)

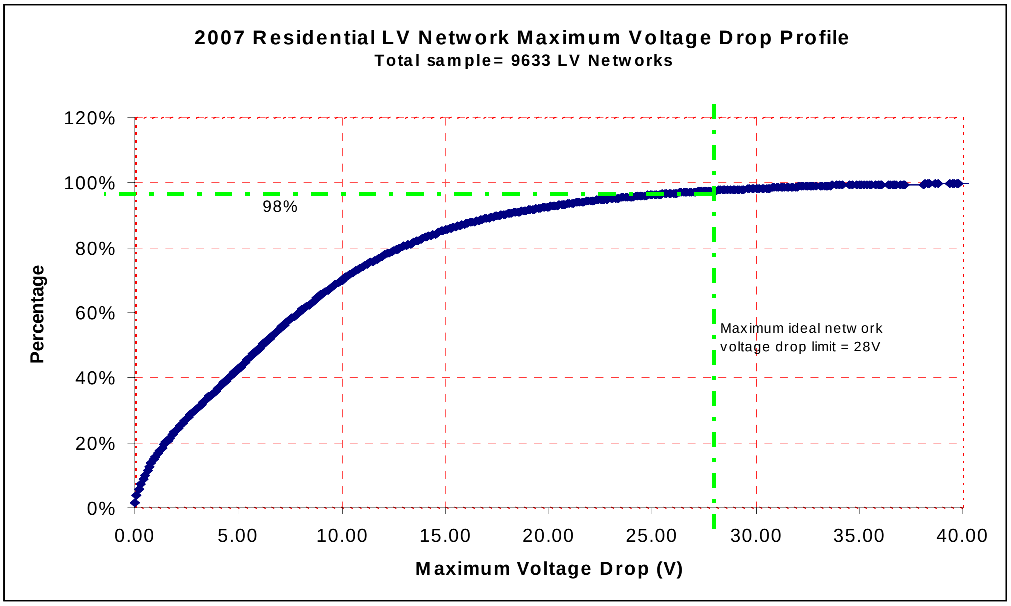
Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	4.98	8.38	11.49	24.85
Forecast volume (switches)	180	300	400	880

7.6.8 Targeted LV network upgrades

This is a new strategy being adopted by Western Power that involves the undergrounding of those parts of the low voltage (LV) overhead network that do not comply with regulatory requirements due to poor power quality or reliability performance[94].

The program of work will be undertaken on a targeted basis, with the selection and prioritisation being based on a combination of the fault history, capacity requirements, and the age of the overhead assets. To assist this process Western Power has developed a supply quality forecasting system that produces a prioritised list of networks for targeted upgrade each year[95]. The result of this forecasting process is presented in Figure 7-9 which shows that of the 9633 predominantly domestic LV networks, 2% or 192 LV networks breach the 28 volt drop limit. Additionally, according to the current fault data, there were approximately 12,200 LV overhead network faults causing supply interruptions in the 48 months to November 2007. This contributed to 14% of unplanned distribution SAIDI minutes over this period, with the worst 94 locations contributing a total of 6.9 minutes.

Figure 7-9 – LV network maximum voltage drop profile



94 The *Electricity Act 1945* and *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, requires Western Power to ensure supply voltage meets regulatory requirement limits at all times.

95 The methodology used in the forecasting system is documented in DMS 4508247 and DMS 4519547.

The targeted LV network upgrades strategy aims to underground a total of 47km of overhead low voltage network at an average rate of 15.5km per annum over the regulatory period. Table 7-30 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy.

Table 7-30 – Targeted LV network upgrade Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	5.47	5.52	5.67	16.66
Forecast volume (km)	15.5	15.5	16	47

7.6.9 'Hills' covered conductor

The “Hills” Area is defined as the area that falls within a 35 – 40km radius from CBD and is the area between the edges of the Darling Scarp to edge of the State Forest. The bare wires in the ‘hills’ area contributes to conductor clashing during severe weather conditions. . By replacing bare overhead conductors with covered conductors, bush fire risks are reduced and reliability improvements obtained.

The implementation of this strategy will achieve a saving of 1.94 SWIS SAIDI minutes, which represents a cost benefit of $7.45M per SWIS SAIDI minute saved.

This strategy aims to deliver the replacement of 75% of all conductors located in extreme bush fire risk zone areas in the “Hills” area, and in total achieves the installation of 63.7km of insulated conductors, and 2053 replacement poles.

Table 7-31 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. It should be noted that submission only covers the first phase of this long-term strategy.

Table 7-31 – 'Hills' covered conductor Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	3.38	6.54	4.83	14.75
Forecast volume				
- HV overhead (km)	0.21	4.24	0.47	4.92
- LV overhead (km)	6.94	10.34	9.41	26.69
- poles	175	528	348	1051

7.6.10 Distribution transformer noise mitigation

The project consists of the construction of noise barriers around padmount substation transformers to reduce noise emissions such that they comply with the requirements of the *Environmental Protection (Noise) Regulations*. The program of noise mitigation work is to be completed at 500 substations over a 5-year period, commencing 2010/11. Non compliance with the requirements of the Western Australian Noise Regulations to reduce the impact of noise emissions on substation neighbours could result in penalties under the Environmental Protection Act.

It should be noted that to date Western Power has focused on non-compliance of transmission transformers (larger transformers in zone and terminal substations with a higher noise output). In order to achieve compliance with Western Power's corporate objectives, attention now needs to be focused on the compliance of distribution transformers. This strategy is also focused on amending the location guidelines for new installations to avoid future non-compliance.

Table 7-26 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on estimates from historical expenditure.

Table 7-32 – Distribution transformer noise mitigation Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	0.00	2.18	4.47	6.65
Forecast volume (substations)	0	50	100	150

7.6.11 Street light switch-wire replacement

This strategy focuses on removing streetlight switchwires that are assessed to be in poor condition and reconnecting the street lights direct to the LV mains via a PE Cell or timed control box.

Table 7-33 shows the forecast work volumes and expected capital expenditure required for the successful implementation of this strategy. This is a new strategy with no previous history, and hence the expenditure timing is based on progressively increasing the work volume to match the estimated conductor deterioration.

Table 7-33 – Street light switch-wire replacement Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	1.21	1.83	3.14	6.18
Forecast volume (km)	100	150	250	500

7.6.12 Other minor safety, environmental, and statutory strategies

Western Power has a number of minor strategies that are being implemented to comply with safety, environmental, or statutory requirements. Safety and environmental considerations are already well embedded in Western Power's systems and processes. However, ongoing expenditure is required in order to meet new requirements and maintain compliance in these areas.

Table 7-34 shows the forecast replacement volumes and expected capital expenditure required for the successful implementation of these strategies. Reference should also be made to the DMS numbers noted against each strategy in the table for further supporting information and other references.

Table 7-34 – Other minor safety, environmental, and statutory strategies Capex forecast ($M)

Strategy	Key driver(s)	Unit	09/10	10/11	11/12	Total
LV spreaders in moderate and low fire risk areas (DMS 4284485)	Bushfire risk Public safety	$M	2.06	1.82	3.73	7.61
		Volume	8,000	7,000	14,000	29,000
Substandard conductor clearance (DMS 4286102)	Statutory - C(b)1 compliance Public safety	$M	3.51	2.55	3.91	9.97
		Volume	68 spans	59 spans	285 spans	412 spans
Line markers for remote road crossings (DMS 4893769)	Public safety	$M	0.13	0.13	2.62	2.88
		Volume	100	200	2,000	2,300
Distribution substation safety and security (DMS 4286350)	Public safety Statutory compliance	$M	2.57	1.64	1.69	5.9
		Volume	600 Subs 2,000 Locks	600 Subs 2,000 Locks	600 Subs 2,000 Locks	1,800 Subs 6,000 Locks
Replacement of under rated stay wires (DMS 4891923)	Statutory - C(b)1 compliance Public safety	$M	0.89	1.79	1.84	4.52
		Volume	1,200	2,400	2,400	6,000
URD pillars replacement (DMS 4286200)	Public safety	$M	1.52	1.57	1.58	4.67
		Volume	1,400 pillars	1,400 pillars	1,400 pillars	4,200 pillars
Conductive poles (DMS 4293956)	Public safety	$M	1.58	1.59	1.64	4.81
		Volume	480 poles	480 poles	480 poles	1,440 poles
Reinforcement of transformer poles (DMS 4888911)	Statutory - C(b)1 compliance[96] Public safety	$M	1.59	0	0	1.59
		Volume	1,300 poles	0 poles	0 poles	1,300 poles
Pole top fire mitigation (retrospective bonding) (DMS 4529961)	Statutory - C(b)1 compliance Public safety Bushfire risk	$M	0.88	0.88	0.91	2.67
		Volume	15,000	15,000	15,000	45,000
Retrofit installation of stay insulators (DMS 4286068)	Statutory - C(b)1 compliance Public safety	$M	0.75	0.76	0.97	2.48
		Volume	1,000 stays	1,000 stays	1,250 stays	3,250 stays

96 Western Power's overhead lines must comply with *Guidelines for the Design, Construction and Maintenance of Overhead Lines* (HB C(b)1) as required by the *Electricity (Supply Standards & System Safety) Regulations*.

Strategy	Key driver(s)	Unit	09/10	10/11	11/12	Total
Cattle care (DMS 4286398)	Environmental	$M	0.71	0.72	0.74	2.17
		Volume	1,000 poles	1,000 poles	1,000 poles	3,000 poles
Ring-tail possum protection devices (DMS 4505200)	Environmental Bushfire risk	$M	0.59	0.59	0.61	1.79
		Volume	200 solutions	200 solutions	200 solutions	600 solutions
Distribution river crossings (DMS 4888795)	Statutory[97]	$M	0.57	0.35	0.59	1.51
		Volume	5 crossings	3 crossings	5 crossings	13 crossings
Mitigation of electric shock hazard from metal street light poles (DMS 4526815)	Public safety	$M	0.30	0.00	0.00	0.30
		Volume	20,000 poles	-	-	20,000 poles
Total ($M)			**17.65**	**14.39**	**20.83**	**52.87**

7.7 SCADA & communications[98]

While Western Power's SCADA and communications infrastructure has only a minimal impact on safety, environment and network reliability, they are essential elements in the overall delivery of these outcomes. These systems provide the link between network operations and the primary power system assets that enable remote supervision and control which has a major impact on supply reliability, operator safety, and environmental outcomes. The SCADA and communications strategies are intended to maintain and develop this infrastructure to support the overall operation and management of the distribution network. Figure 7-10 shows the historical and forecast SCADA and communications capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the forthcoming regulatory period, it is proposed to increase the SCADA and communications capital expenditure from an average of $2.4M per annum in the 2006/07 to 2008/09 period. Excluding an adjustment associated with the reallocation of operating costs to capital in the regulatory period (see note 1 to 1 to Table 3-35) the expenditure over the 2009/10 to 2011/12 period averages $5.9M per annum, which is an increase of approximately 146% over the historical expenditure in this category.

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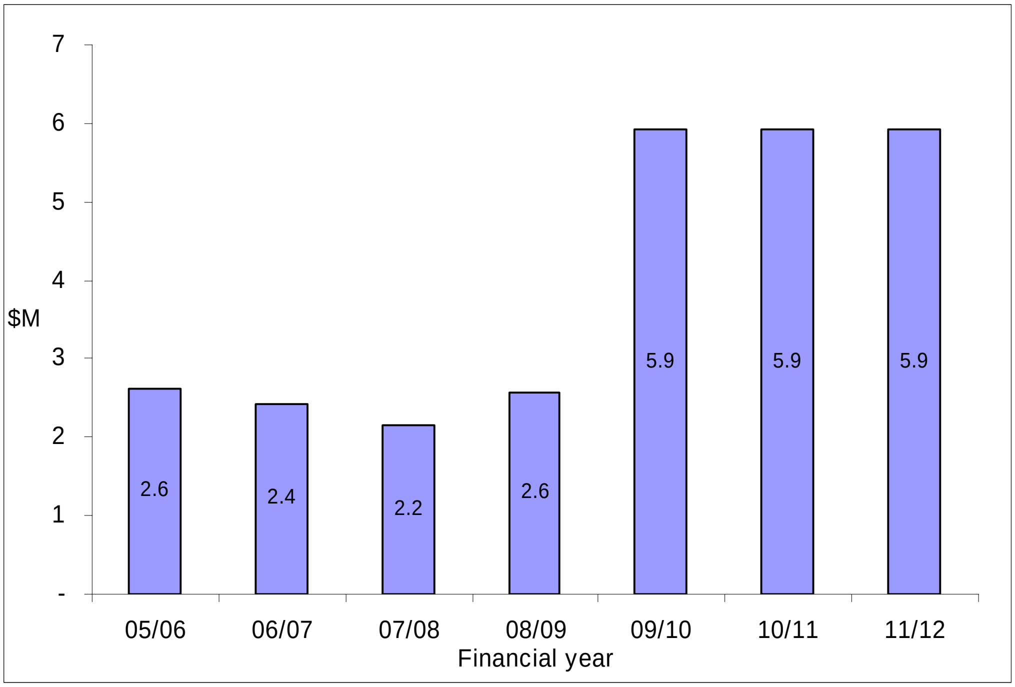
97 *Guidelines for Electricity Transmission and Distribution Work in Western Australia* have been amended to include the *Code of Practice – Power line Crossing of Navigable Waterways in Western Australia*.

98 Excludes estimating risk expenditure component

Figure 7-10 – SCADA and communications capital expenditure



The magnitude and timing of the SCADA and communications capital expenditure is driven by a number of factors; these are:

- third party actions such as the retirement of Telstra's Trunked Mobile Radio
- compliance with regulatory and legislative requirements
- core communications infrastructure growth needs of the business to support network automation and telemetry strategies, as well the introduction of higher bandwidth applications
- the need for a high availability communications network
- short lifecycles of IT and telecommunications hardware and software
- serviceability and availability of spares, and
- safety

It is important to note that Western Power's SCADA and Communications Group is responsible for the provision of "backbone" infrastructure, and not individual SCADA and communications expenditures associated with network capital projects. Hence the strategies summarized in Table 7-35 relate only to the core SCADA and communication infrastructure.

Table 7-35 – SCADA and communications strategies Capex forecast ($M)

Strategy	Key driver(s)	Unit	09/10	10/11	11/12	Total
Distribution automation expansion (DMS 4300122)	Support for distribution automation projects Supply reliability.	$M	1.58	1.65	2.34	5.57
		Volume		See DMS 4300122		
System operations	See note 1 below	$M	1.54	1.25	1.36	4.15
		Volume		Various		
Trunked Mobile Radio Replacement (DMS 4308931)	Supplier service withdrawal	$M	0.22	0.88	0.45	1.55
		Volume		See DMS 4308931		
BPL (broadband over power lines) phase 1 (DMS 4308925)	R&D	$M	0.72	0.73	0.00	1.45
		Volume		See DMS 4308925		
CBD SCADA asset replacement (DMS 4300135)	Compliance[99]	$M	0.00	0.61	0.63	1.24
	Supply reliability	Volume	-	45 sites	45 sites	90 sites
Metro Recloser System RFI Radio Replacement (DSM 4308937)	Support for distribution automation projects	$M	0.44	0.28	0.00	0.72
		Volume		(DSM 4308937)		
Dist auto data concentrator replacement (DMS 4300153)	Unserviceable asset	$M	0.34	0.34	0.00	0.68
		Volume	4	5	-	9
Dist comms tower reinforcement stage 2 (DMS 4372223)	Standards compliance	$M	0.00	0.00	0.63	0.63
		Volume	-	-	6 sites	6 sites
3 phase unbalanced load detection (DMS 4563023)	Improve network utilisation and management Supply reliability	$M	0.49	0.00	0.00	0.49
		Volume	-	-	-	-
Comms mobile trans disaster equipment (DMS 4299808)	Communication network reliability	$M	0.00	0.00	0.49	0.49
		Volume	-	-	1 unit	1 unit
Country mobile radio (DMS 4308647)		$M	0.26	0.18	0.00	0.43
		Volume		See DMS 4308647		
Comms Tower Reinforcement Regulatory Compliance (DMS 4308668)	Regulatory compliance	$M	0.32	0.00	0.00	0.32
		Volume		See DMS 4308668		
Total ($M)			**5.91**	**5.92**	**5.90**	**17.73**

Note 1: Previously this expenditure was expensed

99 Technical Rules Section 2.5.4.2 and the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* Division 3 — Standards for the duration of interruption of supply in particular areas.

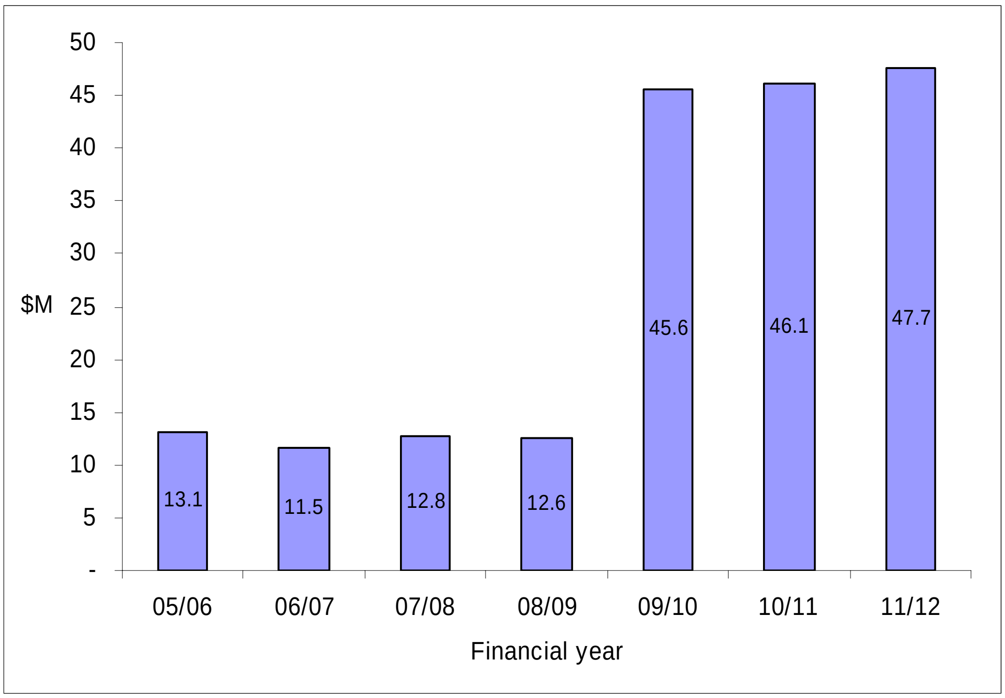
Table 7-35 shows the forecast volumes and expected capital expenditure required for the ongoing management and development of the SCADA and communications backbone infrastructure.

7.8 Metering

Metering capital expenditure includes all expenditures relating to the supply of meters and communications equipment, capitalised meter installation and commissioning activities, new CT metered installations, and the creation of the network connection points.

Figure 7-11 shows the historical and forecast metering capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the forthcoming regulatory period, it is proposed to increase the distribution capacity capital expenditure from an average of $12.3M per annum in the 2006/07 to 2008/09 period, to an average of $46.5M per annum over the regulatory period. This represents an increase of approximately 278%.

Figure 7-11 – Metering capital expenditure ($M)



The magnitude and timing of the metering capital expenditure is driven by new connections and regulatory compliance issues. Specific details of the distribution capacity management strategies are outlined in the following subsections.

7.8.1 Meter change program – three phase

The three phase meter change program is a key element of Western Power's Meter Management Plan which ensures compliance with the requirements of the Metrology Procedure and Metering Code. The code requires that any failed metering population is replaced within 3 years of test failure[100]. This capital expenditure includes all costs related

100 The *Electricity (Supply Standards and System Safety) Regulations 2001* - regulation 9(1) requires the testing of meters and where a meter population is identified as falling outside the

to the replacement of the failed metering population which involved approximately 350,000 three-phase meters throughout SWIS.

Table 7-36 shows the forecast volumes and expected capital expenditure required for the successful implementation of this strategy. This forecast is based on the actual number of three-phase meters installed throughout SWIS.

Table 7-36 – Meter change program – three phase Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	32.47	32.78	33.70	98.95
Forecast volume (meters)	118,800	118,800	118,800	356,400

7.8.2 Meters & associated equipment

This expenditure is required to meet new customer connections, upgrades to the network, meter access (communications) and customer churn (requirement for interval capable meter when contestable customer moves from Synergy). This includes all expenditures relating to the supply of meters, capitalised installation and commissioning costs.

Table 7-37 shows the forecast volumes and expected capital expenditure required to comply with the *Small Use Customer Code*, *Metering Code*, *Customer Transfer Code*, and Service Level Agreements obligations. The forecast volumes are based on estimates of the expected number of new metering points within the SWIS over the regulatory period.

Table 7-37 – Meters & associated equipment Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	12.36	12.69	13.39	38.44
Forecast volumes (meters)	44,000	45,000	46,000	135,000

7.8.3 Other minor metering strategies

Western Power has a number of minor strategies that are being implemented in support of government environmental initiatives (i.e. Solar Cities[101]), or are to maintain Metering Standards Laboratory's NATA accreditation.

Table 7-38 shows the capital expenditure forecasts for these minor metering strategies. Reference should also be made to the DMS numbers noted against each strategy in the table for further supporting information and other references.

accuracy requirements (based on sample testing), the population of meters must be replaced within a three year period.

101 The Solar Cities Program is Western Power's commitment as part of the Federal Governments climate change strategy.

Table 7-38 – Other minor metering strategies Capex forecast ($M)

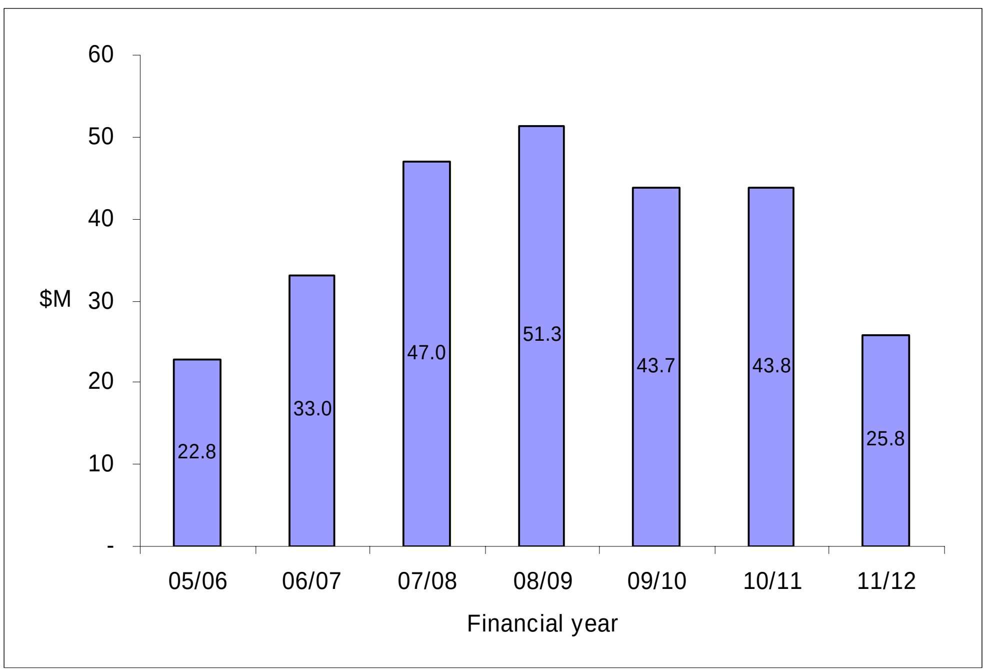
Strategy	Key driver(s)	09/10	10/11	11/12	Total
Solar cities project (DMS 4317256)	Environment Corporate citizenship	0.36	0.37	0.38	1.11
Metering services admin & depot (DMS 4300759)	Standards compliance	0.44	0.22	0.23	0.89
Total ($M)		**0.80**	**0.59**	**0.61**	**2.00**

7.9 Special programs

Special programs of work are undertaken by Western Power in response to Government initiatives, and generally involve special funding arrangements. The following sections outline the special programs to be undertaken during the regulatory period.

Figure 7-12 shows the historical and forecast special program capital expenditure profile from 2005/06 to 2011/12. It can be seen from this figure, that over the forthcoming regulatory period, it is proposed to reduce the special program capital expenditure from an average of $43.8M per annum in the 2006/07 to 2008/09 period, to an average of $37.8M per annum over the regulatory period. This represents a decrease of approximately 14%.

Figure 7-12 – Special programs capital expenditure



7.9.1 State underground power program (SUPP)

In 1995, the Government of Western Australia embarked on a program to retrofit older urban areas with underground power. The Government has since set a target for underground power services to be provided to 50% of residential properties in Perth by 2010, with corresponding improvements in regional towns. The State Underground Power Program (SUPP) is a partnership between Western Power, the State Government, and local Governments, which involves a funding arrangement of 25%, 25% and 50% respectively.

Award of the funding for SUPP works is a competitive process where Local Governments are required to apply for inclusion of specific areas in the program. A two stage selection process involved, with the assessment of proposals against power system reliability criteria and project feasibility criteria. The first stage of the assessment requires a comparative analysis of the overhead distribution network in areas nominated by the local governments. The assessment requires the network reliability (SAIDI) within these areas to be within the bottom 40%. The second stage of the process involves the assessment of each proposal against feasibility criteria such as project cost and nominated areas requirements that ultimately determine a project's feasibility.

The benefits of this work are significant, and include an overall improvement in SAIDI (e.g. the average SAIDI of City Beach was reduced by approximately 80% from 491 to 91 minutes after the installation of underground power), as well as improved public safety and amenity enhancements, elimination of tree pruning, and commensurate reductions in Western Power's operating costs.

Table 7-39 shows the forecast volumes and expected capital expenditure required for the successful implementation of the SUPP strategy. This forecast is based on the cost model described in DMS 2648723 and calculated in DMS 3480909. This cost model was developed as a requirement by the Office of Energy for the selection of Round 4 projects, and uses linear regression analysis. The costing model provides project estimates based on three years of historical project expenditure as well as variables such as extent of rock and street frontage. The three year forecasts expenditure are based on Round 3, 4 and 5 MRP and LEP projects providing underground power to a total of approximately 9300 lots.

Table 7-39 – State underground power program (SUPP) Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	35.32	38.41	22.70	96.43
Forecast volume (Lots)	3,773	3,624	1,905	9,302

7.9.2 Rural power improvement program (RPIP)

The Rural Power Improvement Program **(RPIP)** is partially funded by the State Government through funding contributions by the Office of Energy. The objective of the program is to enhance power supply for rural customers in the South West Interconnected System (SWIS), particularly in relation to projects that are difficult to justify due to the high cost of the work, and the relatively small numbers of customers benefiting from them.

The program commenced in 2004/05 and was originally scheduled to be completed in 2007/08. However due to the success of the project, Western Power expects that funding will be extended across the regulatory period.

Table 7-40 shows the forecast volume of work and the expected capital expenditure required for the successful implementation of the RPIP strategy. Western Power expects this strategy to provide a SWIS SAIDI saving of 0.88 minutes, equating to a cost benefit of $18.83M per SWIS SAIDI minute saved.

Table 7-40 – Rural power improvement program (RPIP) Capex forecast ($M)

Item	09/10	10/11	11/12	Total
Forecast expenditures ($M)	8.41	5.40	3.13	16.94
Forecast volume (programs)	4	4	4	12

8 Distribution Forecast Operating Expenditure

In this section we discuss Western Power's distribution operating expenditure performance during the current regulatory period and also provide forecasts for all distribution maintenance and operational activities including maintenance (corrective and preventive), reliability penalty payments, SCADA and Communications, Network Operations, Metering, Call Centre and several non recurrent projects scheduled for the next regulatory period.

The expenditure forecasts for the next regulatory shown include all technical and business overheads associated with the individual cost categories but do not include corporate overheads which are detailed in a separate section of the submission. Comparisons between historical and forecast transmission operational expenditures, unless stated to the contrary, do not include business support costs.

8.1 Current regulatory period – actual and forecast expenditures

In this section we detail distribution Opex allowances and actual and forecast expenditures for the current regulatory period. We also provide a brief description of the principal reasons for the over expenditures incurred during the current regulatory period.

8.1.1 Regulatory allowances

The annual distribution Opex allowances included in the Forecast Capital and Operating Expenditure Program (FCOEP), for the current regulatory period 2006/07 to 2008/09 are shown in Table 8-1 in nominal dollars.

Table 8-1 – Distribution regulatory allowances including business support costs for the current regulatory period ($M, nominal)

Item	06/07	07/08	08/09
Regulatory allowances	195.6	202.2	211.5

8.1.2 Expenditures in the current regulatory period

Table 8-2 details the regulatory allowances for distribution operational expenditure and the actual and forecast annual expenditures in 2007/08 dollars. It is evident from Table 8-2 that Western Power will spend considerably more on distribution Opex than the regulatory allowances during this regulatory period. The increased expenditure is the result of a deliberate strategy to commence to align Western Power's inspection and maintenance works with its current distribution asset mission statements.

Recent periods of constrained expenditures have resulted in only the highest priority inspection and maintenance work being implemented which is one of the causes for less than optimal outcomes being achieved in network reliability performance, the expenditures on corrective emergency and corrective deferred maintenance and the significant numbers of unassisted asset failures.

Western Power's Board and management have identified this as an important issue and have demonstrated their commitment to rectifying the situation by endorsing considerable additional distribution Opex above the regulatory allowances during this current regulatory period as shown in Table 8-2.

Table 8-2 – Distribution regulatory allowances and actual and forecast expenditures including business support costs for the current regulatory period ($M)

Item	06/07	07/08	08/09	Total
Regulatory allowances	210.6	208.2	211.5	630.3
Actual and forecast expenditures	254.0	259.5	263.0	776.5

8.1.3 Significant categories of additional expenditures in the 2006/07 financial year

The significant drivers for the additional expenditure during this current regulatory period are the carry over expenditures, cost uplift, OSA shortfall, volume increases and delays to the summer ready program. These drivers are discussed in the following sub sections with all expenditures expressed in 2007/08 dollars.

Carry-over work

Carry over work includes work that was originally planned for 2005/06 but carried out in 2006/07 and work that was carried out during 2005/06 but invoiced in 2006/07. The most significant expenditures relate to the 40 Worst Feeder (40WF) program with $3.9M of rectification works carried over to 2006/07. Other works carried over from 2005/06 included silicon spraying of insulators ($0.5M), pole based inspection and treatment ($1.6M) and ground mounted substation inspections ($0.5M).

Works carried out in 2005/06 but invoiced in 2006/07 included 40 WF rectification works ($3.1M), Vegetation ($0.8M) and miscellaneous works ($0.8M). In all, carry over works accounted for $11.3M of the additional expenditure incurred in 2006/07 over the regulatory allowance.

Cost uplift

The original estimates for 2006/07 distribution operational expenditures did not include escalators for labour, materials or external contractor costs. Since preparing the estimates in 2005, Western Power has experienced real rising labour, material and contractor costs in line with other electricity businesses throughout Australia. In fact the current infrastructure boom in Western Australia is placing additional pressures on available resources in the region and is also affecting contract costs.

Western Power has estimated that cost uplift alone has resulted in additional Opex costs of $7.8M in 2006/07. This estimate is based on sampling a range of activities in each maintenance category and establishing indicative unit of work cost increases.

Increase in work volumes

The distribution work volumes that formed the basis of the Opex forecasts in the FCOEP for the current regulatory period have proven to be inadequate since they failed to fully reflect the actual condition of the distribution assets under management and the maintenance regime detailed in the asset mission statements. Additional work volumes also resulted from an increase in asset faults as a result of the poor condition of some of the distribution assets. Both these drivers of additional work volumes are related to the previous years constrained distribution operational expenditures.

In total Western Power has estimated that the increase in work volume accounts for approximately $11.9M of additional expenditure when compared to that included in the FCOEP for 2006/07. There have been substantial increases in the major fault volumes resulting in a corresponding increase in corrective maintenance costs.

In relation to asset condition, the increased condition assessment programs, undertaken effectively for the first time in many years commenced during this regulatory period, have resulted in higher volumes of condition-based rectification works being identified. For example, a substantial number of feeder bays in low and moderate fire risk areas were identified as requiring vegetation trimming to maintain statutory clearances, and the inspections associated with the 40WF rectification works have identified conditions requiring more work than originally estimated.

One step ahead (OSA) efficiency savings

Expenditure savings were incorporated in the distribution operation expenditure forecasts in the FCOEP for this period. In 2006/07, forecasts savings of $7.1M were factored into the forecasts, however it has been estimated that actual cash savings for this year will be less than $1.8M leaving a shortfall of $5.3M.

Summer-ready delays

The Summer Ready program requires Western Power to provide alternate power supply arrangements as a requirement under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005.* Where practicable, Western Power has to supply generators for customer supplies if planned outages are expected to exceed 6 hours or 4 hours on days where the temperatures are expected to exceed 30 degrees. To ensure compliance Western Power needed to hire additional generators for the 2006/07 financial year at a cost of $1.3M.

8.2 Forecast expenditures

In this section we detail Western Power's forecast distribution operational expenditures including the impact of cost escalation associated with labour, contract services and material costs. The forecasts do not include corporate overheads which are detailed separately. We also discuss the methodologies used to develop these forecasts.

8.2.1 Forecast distribution Opex

The following tables indicate Western Power's forecast distribution operational expenditures over the next three year regulatory period from 2009/10 through to 2011/12.

Table 8-3 – Forecast distribution Opex including cost and asset escalation and excluding business support costs ($M)

Item	09/10	10/11	11/12	Total
Forecast distribution Opex	317.41	337.77	355.58	1010.76

These annual forecast operational expenditures comprise the recurrent and non-recurrent expenditures shown in Table 8-4.

Table 8-4 – Forecast distribution Opex categories including cost and asset escalation and excluding business support costs ($M)

Distribution Opex categories	09/10	10/11	11/12
Preventative routine maintenance	54.11	56.33	59.36
Preventative condition maintenance	91.22	93.07	95.91
Corrective deferred maintenance	23.33	25.71	28.45
Corrective emergency maintenance	71.03	74.31	78.45
Non reference services	7.42	8.61	9.82
Reliability Driven Maintenance	1.06	1.08	1.11
SCADA/communications	1.39	1.43	1.62
Network operations	20.03	21.83	23.20
Call Centre	5.37	5.57	5.55
Metering	20.21	24.46	29.07
Demand Side Management	5.02	3.42	1.14
Field survey information capture	2.00	6.09	6.25
Alternate Funding of Training	9.62	10.28	9.83
DA-Sequence Switching	0.14	0.14	0.15
Energy Solution R&D program	5.46	5.55	5.70
Total (M)	**317.41**	**337.88**	**355.61**

During 2007/08 Western Power carried out a comprehensive review of all distribution preventative maintenance inspection and tests and the associated condition maintenance works identified from these inspections and tests. This review was instigated as it was realised that the regulatory allowances would not be sufficient to facilitate all the inspections and maintenance operations detailed in the distribution asset mission statements and the associated rectification works.

The review was a 'bottom up' investigation where asset quantities were reviewed, asset mission statement requirements aligned with inspection and testing programs, recommended inspection periodicity was aligned with inspection and testing programs and the correlation between preventative routine maintenance and the consequential remediation works was checked for accuracy. The revised work programs were then reviewed for prudence, and reasonableness. The review also included quantification of the impact of any additional works on support function such as Network Operations, and SCADA and Communications and was conducted by developing 87 activity templates for all the significant distribution activities.

Following this review, asset volumes as at the commencement of the 2009/10 financial year have been forecast. The additional switching and outage planning associated with these proposed additional maintenance works have been used to forecast the additional resources required in Network Operations.

The other components of recurrent distribution Opex such as Corrective Emergency Maintenance and Corrective Deferred Maintenance, SCADA/Communications, and Metering were individually forecast based on the expected growth of the relevant expenditure drivers resulting from the proposed additional maintenance works and the proposed capital works program.

The non-recurrent Opex projects, such as Field Survey Information Capture and Demand Side Management Program were independently estimated. The Field Survey Information Capture project which relates to the capture and validation of distribution asset data and position is fully described including identifying the benefits in an activity template detailed in the Opex tracker.

On completion of the 'bottom up' review a 'top down' test was carried out to check all components of the forecast future expenditures for reasonableness. This 'top down' review included assessment of the reasonableness of the asset quantities, inspection and maintenance processes, procedures, and in some cases, maintenance philosophies detailed in the asset mission statements.

This comprehensive review has been designed to ensure that the distribution network operates in compliance with all current regulatory, statutory, safety and environmental requirements, and its asset mission statements. This should result in enhanced network reliability performance and reduced unplanned asset failures over time.

The distribution Opex forecasts included in this submission reflect the outcomes of this comprehensive review and if the additional inspections and maintenance and repair works are implemented Western Power expects that all stakeholders will benefit from improved reliability of supply, reduced unplanned asset failures such as fewer unassisted pole failures, and reduced expenditures on emergency network repair expenditures over time.

8.2.2 Comparison of expenditures in current and next regulatory periods

Figure 8-1 and Table 8-5 details the actual and forecast operational expenditures for 2005/06, the current regulatory period and the operational expenditures forecast for the next regulatory period.

Figure 8-1 – Comparison distribution operating expenditure ($M)

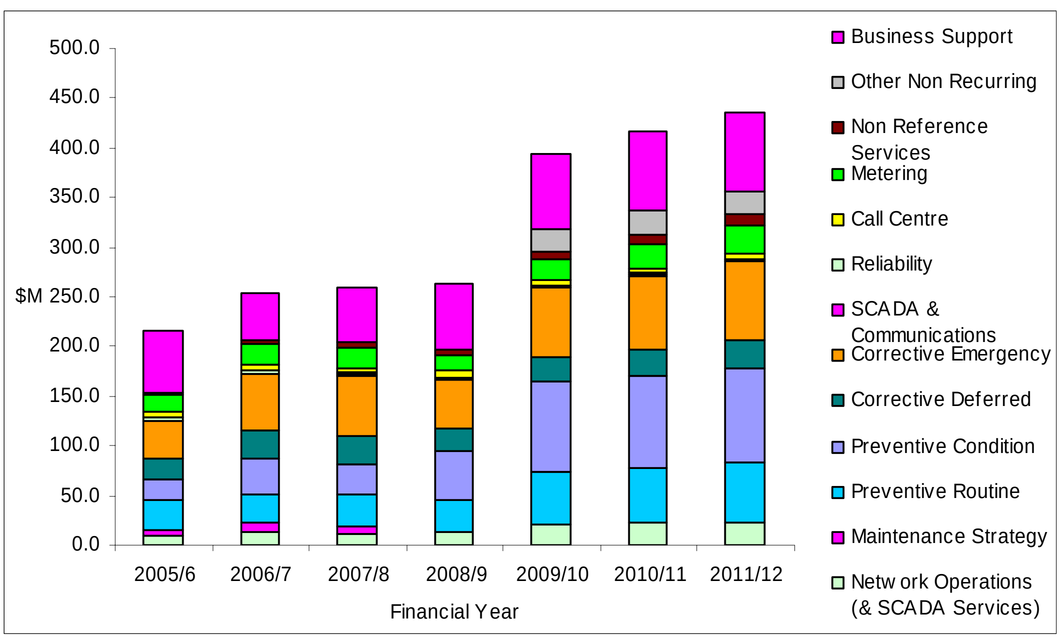


Table 8-5 – Comparison of actual and forecast distribution operational expenditures excluding business support costs ($M)

Item	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Maintenance strategy[102]	5.80	9.58	8.86	0	0	0	0
Preventive routine	30.89	28.95	30.90	31.74	54.11	56.33	59.36
Preventive condition	20.56	35.62	31.82	49.52	91.22	93.07	95.91
Corrective deferred	20.18	27.66	28.11	22.82	23.33	25.71	28.45
Corrective emergency	38.29	56.50	60.45	48.83	71.03	74.31	78.45
Reliability	2.31	3.77	1.55	1.95	1.06	1.08	1.11
SCADA & communications	0.87	1.40	1.24	1.08	1.39	1.43	1.62
Non reference services	2.18	4.84	6.13	5.30	7.42	8.61	9.82
Network operations[103]	9.34	13.33	10.77	13.56	20.03	21.83	23.20
Other (non recurring)	0	0	0	0.03	22.24	25.47	23.05
Call Centre	6.26	5.26	5.12	6.40	5.37	5.47	5.55
Metering	17.48	20.11	19.23	15.9	20.21	24.46	29.07
Business support	61.68	46.95	55.35	65.82	76.58	78.70	80.80
Total (M)	**215.84**	**253.97**	**259.53**	**262.95**	**393.99**	**416.47**	**436.39**

The major components of the proposed increase in distribution operational expenditures from 2008/09 to 2009/10 are as follows.

Increased asset quantities

Western Power proposes to implement a substantial distribution capital works program of approximately $2.29B, over the next regulatory period. This will result in a considerable increase in the quantity of distribution assets requiring inspection and operation during the three year period. The forecast Opex includes allowances to manage these additional assets which will be increasing at a rate substantially higher than historical growth rates.

The growth in distribution assets resulting from the proposed growth related capital works accounts for a significant percentage of the forecast Opex estimates.

Cost uplift

Western Power has engaged an independent expert[104] to provide advice on the likely real increases in external labour and material costs expected over the next regulatory period. In addition Western Power's HR department has provided guidance on the likely real increase

[102] Maintenance strategy activities are treated as a component of the direct overhead cost from 08/09 onwards

[103] Includes SCADA Services costs that support NOCC and SOCC mainframe SCADA systems etc.

[104] Access Economics, 2008, *Material and Labour Cost Escalation Factors*, DMS# 4575552

in internal labour costs expected to be incorporated into rates as a result of enterprise bargaining.

In combination, significant real increases in both labour and material costs are expected over the next regulatory period and have been factored into the forward estimates. These real cost increases have a significant impact on the magnitude of the forecast expenditures.

Pole maintenance

This distribution maintenance cost category relates to the remedial work arising from a new inspection regime which combines pole ground line inspections with pole top and line inspections. Recent data has been used to determine the link between these new inspections and the quantity of remedial conditions identified. Expenditures are forecast to increase from $12.5M in 2006/07 to $27.5M in 2009/10.

In addition the average cost to rectify a condition has increased from $1,047 to $1,400 due to higher contractor costs.

Power pole bundled inspections

Western Power has bundled the ground line inspection and treatment of poles with above ground pole inspection and line inspections. This has resulted in efficiency savings but has necessitated the use of trained linespersons to carry out the inspections. The forecast for power pole bundled inspections do not include any change in the volume of inspections as they will continue to be based on the total pole population being inspected over a 4 year cycle. In addition it is proposed that Western Power carries out inspection of the customers services during the power pole bundled inspections.

However, it is proposed to enhance the pole ground line inspection process to include either full excavation of the soil around the base of the pole to a depth of approximately 500mm in line with current Australian practice or to introduce an alternative pole strength testing technique currently under trial. Either option will increase the current costs of pole ground line inspection but Western Power considers the changes necessary to improve the current rate of pole failures from 3.4/10,000 to around the industry average of 0.35/10,000.

Western Power has tested ultrasonic ground line inspection of its poles and initial results indicate a 4% failure rate which is more in-line with current unassisted pole failure rates. The forecast expenditure for this essential preventative maintenance operation has been increased from $7.6M in 2006/07 to $17.9M in 2009/10.

Ground-mounted switchgear/substation inspection and maintenance

Budgetary restraints have resulted in only minimal expenditures on the inspection and maintenance of ground mounted substations and switchgear. Western Power proposes to commence an inspection and maintenance regime of these assets in accordance with current asset mission statements. It has been estimated that operational expenditures will increase from $1.3m in 2006/07 to $11.9m in 2009/10 if the additional inspections and resulting maintenance and repair works are implemented.

Emergency response generators

Western Power has a requirement under the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, where practicable, to supply generators for customer supplies if planned outages are expected to exceed 6 hours or 4 hours on days where the temperatures are expected to exceed 30 degrees. In addition to the base fleet of 19 generators Western Power hires an additional ‘summer ready’ fleet of 16 additional generators in order to comply with this requirement.

Planned work accounted for 51% of generator utilisation from January 2007 to November 2007. Additional expenditures have been included for generator deployment in the next regulatory period because Western Power intends to decrease the number of customers affected by planned outages and the SWIS SAIDI minutes by deploying emergency response generators to 400 additional planned maintenance events per annum. On average each planned interruption is responsible for 0.03 SWIS SAIDI minutes and in total 44.2 SWIS SAIDI minutes.

Annual forecast generator hire will average $6.17M per annum over the next three year regulatory period.

Vegetation management

Vegetation management in the SWIS is governed by a vegetation management strategic plan. The latest edition of this plan takes a risk based approach with extreme and high fire risk zones and urban areas inspected and cut as required on an annual basis, moderate fire risk zones on a two yearly cycle and low fire risk zones on a three yearly cycle.

Previously moderate risk zones were inspected and cut on a 3 yearly cycle but this was found to deliver inadequate performance as regrowth into the clearance area was occurring prior to the next inspection and cut resulting in an unacceptable number of fires occurring. The reduced time between cutting cycles in the moderate risk fire zones, from three to two years, accounts for a significant proportion of the proposed additional expenditure in the next regulatory period.

In addition due to the size of the vegetation contract Western Power proposes to split the contract into two separate contracts in order to minimise the risk of having only one contractor. In addition this will establish and maintain commercial competitive tension between the contractors. Western Power believes that the small increase in costs resulting from the duplication of management overheads, knowledge systems and contract administration costs will be more than offset by the reduced risk of having only one contractor and improved delivery performance.

The proposed changes to the vegetation management processes will increase forecast expenditure from $18.18M in 2006/07 to $ 33.04M in 2009/10.

Bulk globe replacement

A four year bulk globe replacement program was commenced during the current regulatory period based on results of similar bulk globe replacement trials carried out within Australia. These trials indicated that bulk globe replacement programs are more efficient than replacing failed lamps identified by either street light patrols or customer fault reports. A further study[105] carried out by Western Power has indicated that the increase in costs to

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[105] DMS 4004202 – Review of street light preventive maintenance practice (bulk globe replacement program) at Western Power

reduce the bulk globe replacement cycle from four years to three would be offset by a reduction in the required number of fault repairs and an improvement in customer safety, resulting from a reduction in the number luminaire outages. In addition increased lumen output would be achieved as lamps would be replaced prior to their lumen output falling below 70% of the initial value and the luminaire lens would be cleaned more frequently.

Western Power is phasing-out the use of mercury vapour lamps and moving to the high pressure sodium lamps and is also trialling the use of highly efficient compact fluorescent lamps. Both these strategies involve the replacement of the entire luminaire due to the age of the current fitting and the different control gear required for the different lamps.

These proposed changes to the bulk globe replacement program will result in increases to forecast expenditures of approximately $1.0M from 2008/09 to 2009/10.

Non Reference Services (NRS)

The expenditure for the miscellaneous support services covered by NRS has increased significantly, particularly for activities impacted by the high level of state economic activity – for example the relocation of incumbent assets for industrial, commercial and residential property developments.

8.2.3 Estimating methodology

The preventative routine maintenance and the preventative condition maintenance works identified as a result of the comprehensive review detailed in Section 8.2.1 have been costed by a distribution estimating group established specifically to provide distribution cost estimates for this submission. These cost estimates are based on a combination of recent contract rates, historical job costs, or estimates produced by the Distribution Quote Management System (DQM). DQM, which is a well established distribution estimation program used extensively within Western Power, is frequently updated with current material costs, labour and contractor rates and person hours required for each process. The DQM estimating program is frequently revised to reflect actual work as executed information as projects are completed.

A detailed spreadsheet has been constructed, at activity based cost category level, which combines the quantity of asset maintenance works with the cost estimates and produces annual forecast asset related maintenance estimates.

The Corrective Emergency Maintenance and Corrective Deferred Maintenance forecasts were estimated by analysing the expenditure trends over recent years in real terms and using linear regression analysis to predict future expenditures. This method acknowledges the fact that the current and proposed additional maintenance programs will not result in immediate reductions in corrective emergency or deferred maintenance expenditures. The reduction in asset failures and associated maintenance expenditures lags the implementation of additional maintenance works but should be evident within 4 to 5 years i.e. towards 2012/13.

The other recurrent distribution operational categories such as SCADA/Communications, Network Operations, Metering and Call Centre have been reviewed in a similar fashion to the asset related maintenance works with activity templates being developed to forecast work volumes for the 2009/10 financial year. Cost estimates have been developed for these forecast works based on labour rates and current material costs. Estimates for the later years of the next regulatory period have been developed by escalating the volumes for the

2009/10 year to reflect the proposed increase in maintenance works and the proposed distribution capital works programs.

Non-recurrent Opex projects, such as the Field Survey Information Capture, have been independently estimated and detailed in an activity template that identifies both the costs and benefits resulting from the proposed works.

The estimates produced by these processes have not been escalated to account for the forecast real increases in labour, contract services or material costs, nor do they include any contingencies or business support costs. Escalation of these base estimates is carried out in the Opex model to reflect the real forecast increases in labour and materials as well as the impact of the proposed capital works program as discussed in Section 7.

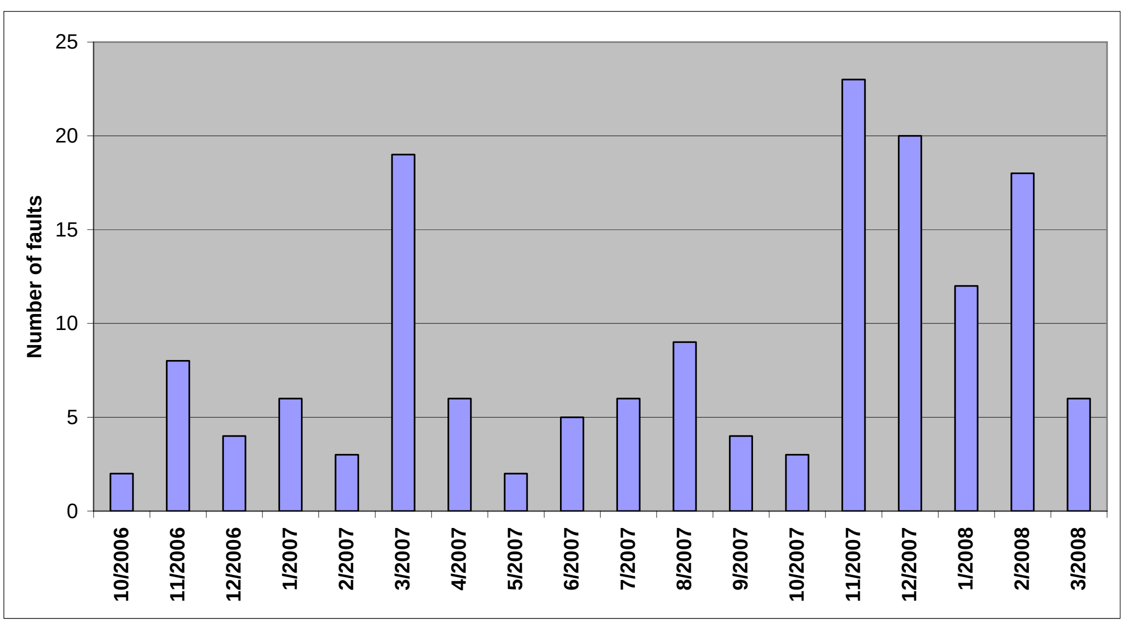
8.2.4 Recurrent preventative maintenance

Preventative maintenance comprises preventative routine and preventative condition maintenance. Preventive Routine Maintenance is proactive maintenance carried out to reduce the probability of failure or degradation of the performance of specific network assets. The activities relate, primarily, to the monitoring or maintenance of equipment and the work is generally of short duration and typically includes visual inspections, testing, lubrication regimes and routine minor part replacement.

Preventive Condition Maintenance relates to the follow-up maintenance and repair activities identified through the preventive routine maintenance programs.

During the next regulatory period Western Power proposes to align all preventative routine maintenance with the relevant asset mission statement which will substantially increase the forecast expenditure on these works. In addition, increasing inspections and testing will result in increased volumes of remedial maintenance being identified with a corresponding increase in associated expenditures.

Figure 8-2 – Ring Main unit defects by month



As an example, it is proposed to substantially increase Substation Bundled Inspections during the next regulatory period. In 2008/9 expenditures are forecast to be $1.5M but in 2009/10 the forecast expenditure is approximately $11.9M per annum. The principal reason for the increase in inspections is that during summer 2007/08 there was a significant increase in ring main unit faults as shown in Figure 8-2. Additional inspection and maintenance works proposed during the next regulatory period should reduce these faults to less than 2 per month. The following chart demonstrates the significant increase in ring main unit faults over summer 2007/08.

Western Power has a backlog of conditions outstanding from the current regulatory period which will be carried over into the next period. This backlog was quantified by using the Distribution Facilities Management System (DFMS) data base to collate all the outstanding preventative condition maintenance (K2) defects currently logged as open. The data was cleansed, for example to remove double counts etc and then analysed for reasonableness.

As the current expenditure K2 maintenance is not sufficient to remedy all the conditions identified by the inspection and testing programmed for this year and next, the condition maintenance backlog will increase prior to the start of the next regulatory period. Hence the carry over into the next period will be correspondingly larger, and the quantity of these additional expected outstanding conditions was estimated and added to the current backlog.

Western Power now collates distribution conditions by maintenance inspection areas and programs the remedy of these conditions following each four yearly inspection cycle. It is proposed to reduce the backlog by combining these backlog conditions with the newly identified conditions and issue a combined works order to cover the remediation of all defects in each maintenance area. Labour and plant cost efficiencies of 30% expected as a result of carrying out the work in conjunction with other programmed maintenance works, such as reductions in travelling time, traffic management and outage management costs have been incorporated into the cost estimates.

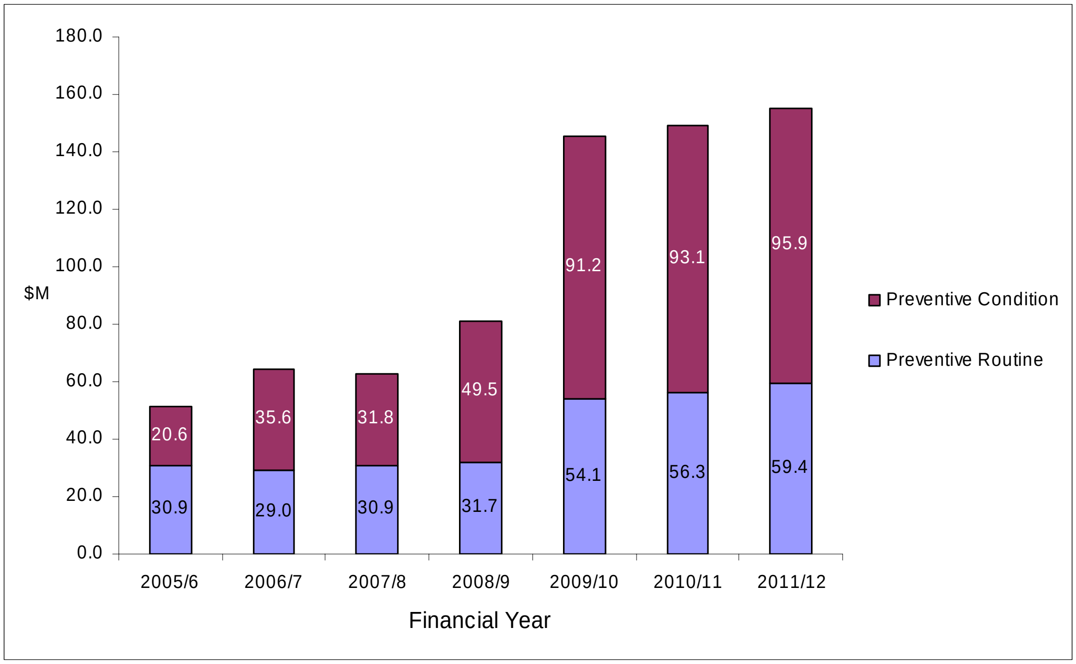
Table 8-6 shows the forecast expenditures for both preventative routine and preventative condition maintenance proposed for the next regulatory period. The costs of removing the backlog are included in the preventative condition maintenance forecasts.

Table 8-6 – Distribution preventative maintenance actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Preventive routine maintenance	28.95	30.89	31.73	54.11	56.33	59.36
Preventive condition maintenance	35.62	31.82	49.52	91.22	93.07	95.91

Note: Historical data excludes strategic planning support costs.

Figure 8-3 – Distribution preventive maintenance expenditure ($M)



8.2.5 Recurrent corrective maintenance

Corrective maintenance comprises corrective deferred maintenance and corrective emergency maintenance. Corrective Deferred maintenance includes the repair of failed or damaged equipment which do not present an emergency situation. These works usually arise following an emergency supply restoration where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the work or rebuild the assets at a later stage.

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.

Corrective maintenance forecasts for the next regulatory period have been developed by applying linear regression analysis to historical data converted to real dollars. The methodology implies that the impact of the proposed additional preventative maintenance will not be evident to any significant extent till after the end of the next regulatory period. Western Power does not believe that this is an unreasonable proposition as the lag between increasing maintenance and reduced unplanned or unassisted asset failures is several years as maintenance programs take time to ramp up to full capacity.

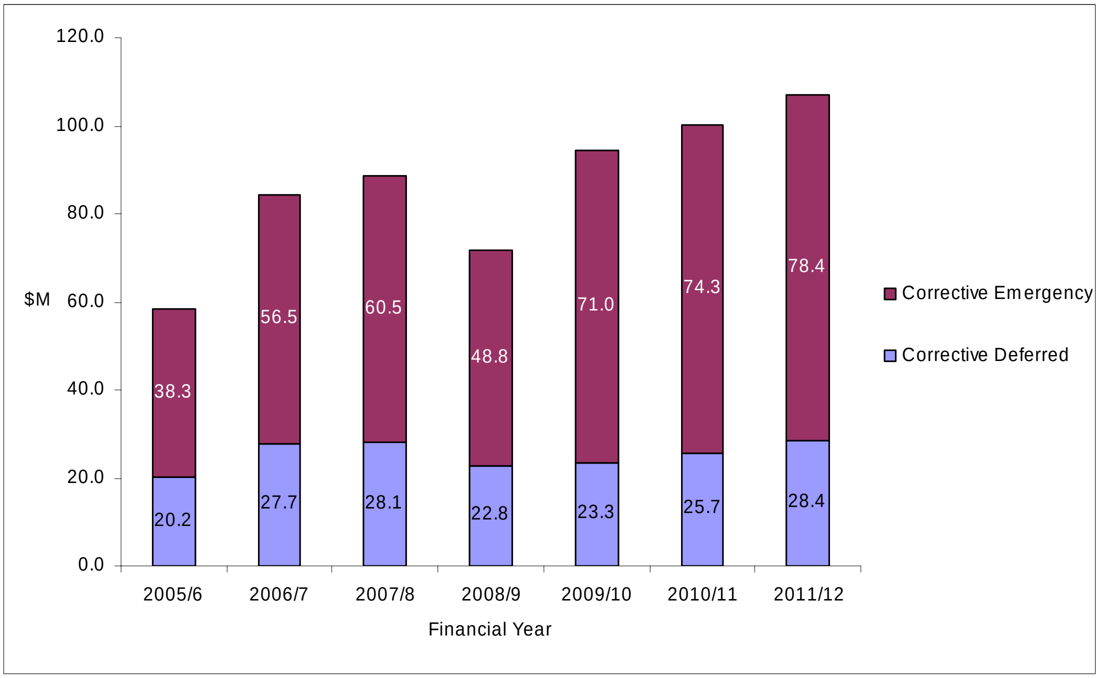
The corrective emergency maintenance and corrective deferred maintenance forecast expenditures for the next regulatory period are detailed in Table 8-7. Significant factors contributing to the step change in forecast expenditures from 2008/09 to 2009/10 are the forecast high real increases in labour, contract services and material, volume increases and the forecast increase in emergency response generator (ERG) hire costs.

Table 8-7 – Distribution corrective maintenance actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Corrective deferred maintenance	27.66	28.11	22.82	23.33	25.71	28.44
Corrective emergency maintenance	56.50	60.45	48.83	71.03	74.31	78.45

Note: Historical data excludes strategic planning support costs.

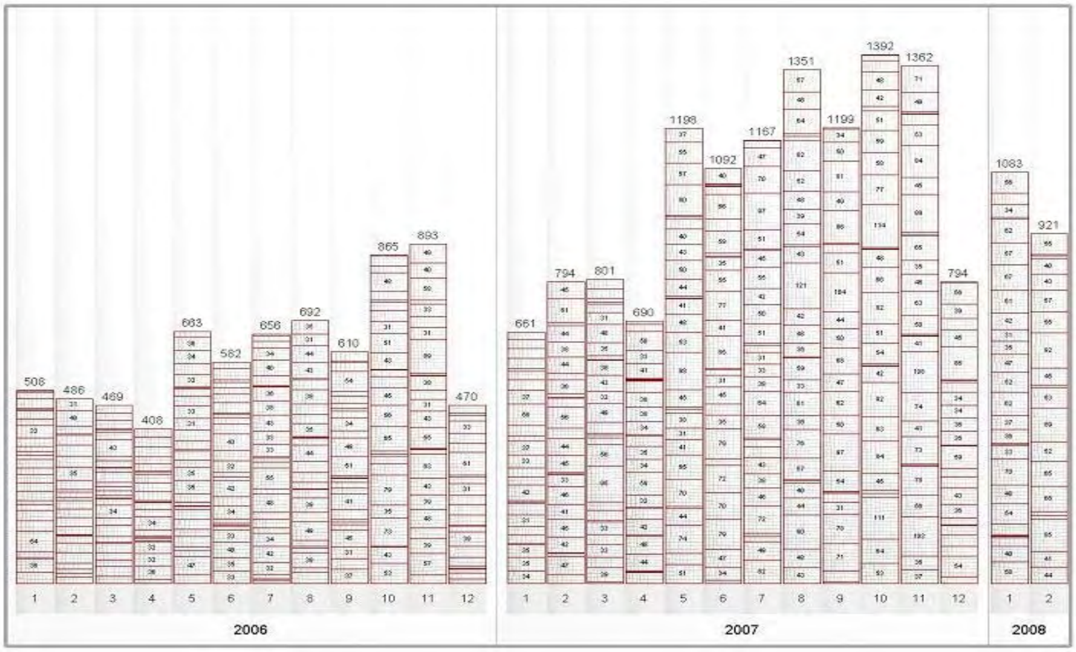
Figure 8-4 – Distribution corrective maintenance expenditure ($M)



8.2.6 Network operations

The primary driver of forecast expenditure in the network Operation Control Centre **(NOCC)** is the quantity of distribution network access requests. These requests have grown by 66% from 2005 to 2006 and a further 71% from 2006 to 2007 as shown in the following chart.

Figure 8-5 – Distribution network access requests



Source: Western Power

The growth in forecast NOCC Opex included in the total distribution operational forecasts consists predominantly of staffing increases. The key NOCC functional and expenditure areas are as follows:

System management

This expenditure category includes 50% of the operational costs of System Management administration. System Management covers both the transmission and distribution network operation and management and hence costs have been allocated equally to distribution and transmission Opex.

SCADA & information systems branch

The expenditure forecast for this function includes 50% of the operating costs of the SCADA & Information Systems Branch. This branch manages the operations of the SCADA Master Stations to provide “real time” visibility and control capabilities to support the System Management Division. This is a critical facility required for the operation of the distribution network and the operating costs of this branch are shared with the transmission SOCC.

These costs relate primarily to the staffing costs such as recruitment, training and development and health and safety activities and the software maintenance and licence costs associated with the ENMAC Distribution Management System.

Control room operation

It is proposed to establish an additional operations desk, Metro South, to cope with the increasing workload resulting from the distribution network expansion and the increasing planned routine maintenance works. This additional desk will be manned on a 24x7 basis and will result in a step jump of 5 FTEs. In all it is proposed to increase FTEs in the control room from 35 to 42 over the three year regulatory period.

Network operation data management

This NOCC functional unit is responsible for the development of operation schedules and switching programs. The increasing capital works program for both growth related and asset replacement activities is resulting in higher workloads for this unit. Accordingly it is proposed to increase staffing levels over the three year regulatory period from 17 in 2009/10 to 19 in 2011/12.

Operational support

The NOCC operation support functional unit is responsible for maintaining the decision support systems (ENMAC data model), communication infrastructure and maintenance of the NOCC policy and procedure manuals. It is proposed to increase staffing levels in the operational support unit by 2 FTEs over the three year regulatory period to cope with the forecast additional workload.

ORC support

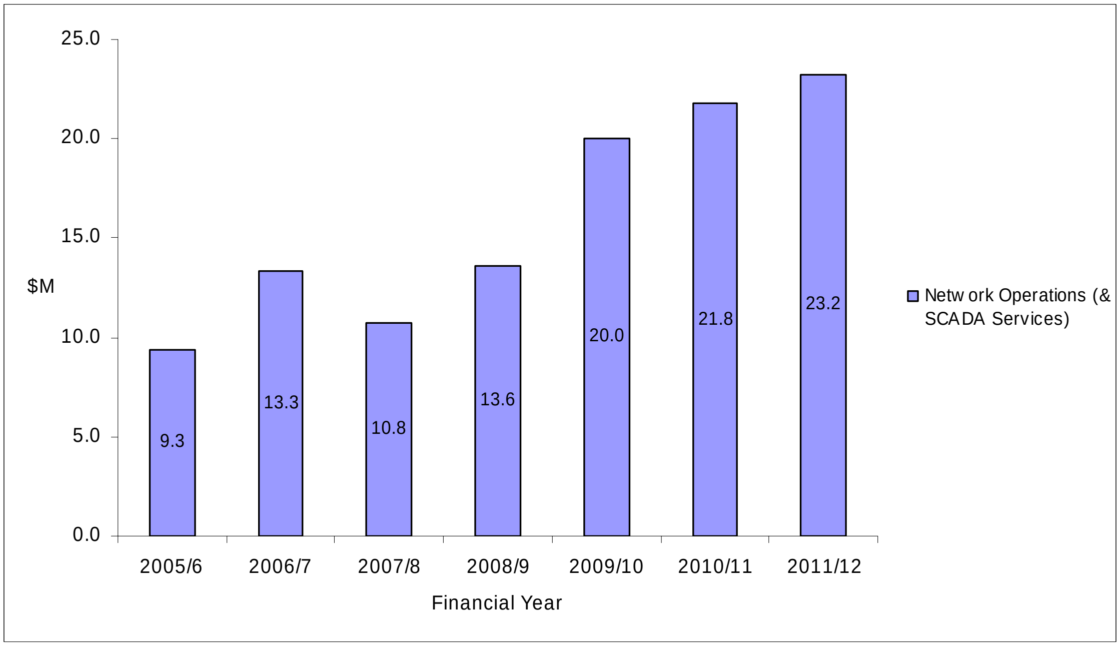
The Operational Reliability Capacity group (ORC) is responsible for the development of contingency plans, and monitoring network loads and reconfiguration of the network. The growth in the network is placing increasing demands on this group and there is currently a backlog of work. It is proposed to increase staffing levels in this group by 2 FTEs from 4 to 6 over the next regulatory period.

Table 8-8 details the forecast NOCC Opex included in the total distribution forecast expenditures for the next regulatory period as well actual and forecast expenditures during the current regulatory period.

Table 8-8 – Distribution network operations actual and forecast expenditures including cost escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Network operations	13.33	10.76	13.56	20.03	21.83	23.20

Figure 8-6 – Distribution network operations expenditure ($M)



8.2.7 SCADA/Communications

The Western Power SCADA and Communications group provides strategic planning, maintenance and operations, and radio communication licenses for the distribution network. Projected operating costs for distribution SCADA and communications over the review period includes the operation and maintenance of the radio network including licences, strategic planning and network optimization for the distribution SCADA, communications systems and distribution automation, and now SCADA field maintenance which was previously included in System Management.

The SCADA and communication Opex costs are trending up as the deployed SCADA and communication asset base increases in line with the expansion of the network, and the continued roll out of distribution automation and smart grid initiatives. There is a small step change in 2009/10 when SCADA field maintenance Opex costs were included in this category.

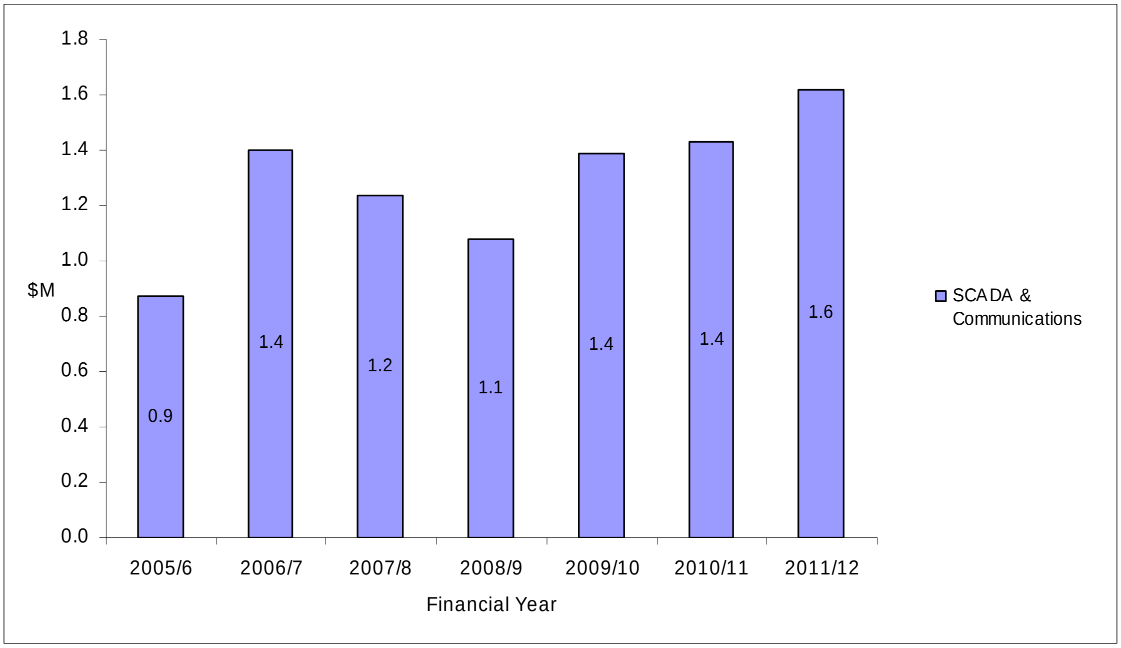
The forecast expenditure for the SCADA and Communications group included in the total distribution Opex forecasts for the next regulatory period, as well as actual and forecast expenditures for the current regulatory period are shown in Table 8-9.

Table 8-9 – Distribution SCADA and communications actual and forecast expenditures including cost and asset escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Dist. SCADA & comms	1.40	1.24	1.08	1.39	1.43	1.62

Note: Historical data includes business support costs.

Figure 8-7 – Distribution SCADA & communications expenditure ($M)



8.2.8 Metering

Metering services forecast operating expenditure relates to the provision of the following meter and connection related services:

- regulatory inspections services
- metering provision including field maintenance and laboratory activities
- data management including administration and meter reading.

Inspections Services covers the regulatory requirement under the *Electricity Regulations* 1947 to maintain a system of inspections to ensure customer installations are safe for connection and use. Activities included in this expenditure category are installation inspections, contractor auditing and breach investigations. The current staffing level of 28 FTE is considered sufficient to cater for the anticipated work load over the next regulatory period.

Meter Reading and Data Management includes the regular reading of customer meters across the Western Power network as well as the management of the meter data to allow settlement and customer billing. Data Management covers the process of data validation and provision of the consumption and interval data for market participants. Meter Reading covers the process of manual data collection of the consumption and interval data for market participants.

The majority of the expenditure for meter reading and data management is directly related to the number of meters in the network. Western Power outsources meter reading via a competitive tendering process and the current provider was selected from a short list of three national meter reading providers. During the next regulatory period individual meter readings are forecast to increase from 6.05 million per annum to 7.37 million per annum.

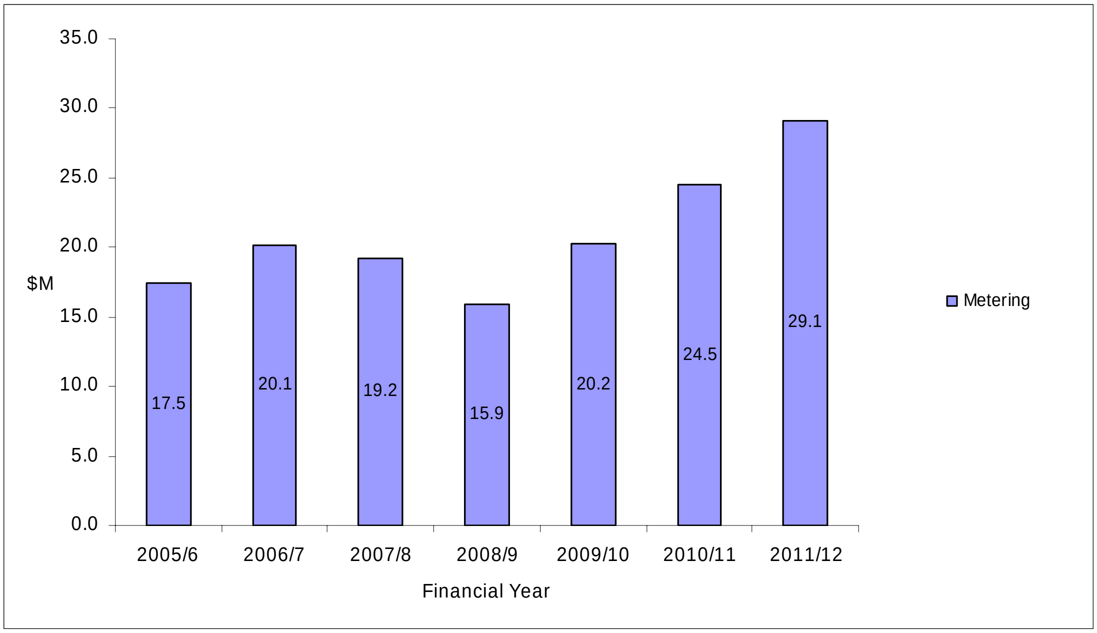
Metering Provision covers the maintenance activities for more complex current transformer (CT) metering installations and includes meter asset integrity, meter provision and the CT meter audit program. Additional costs have been included from 2009/10 in forecast expenditures for this cost category to facilitate the *Metering Code* obligation to audit all CT metering installations over a five year cycle.

The forecast expenditure for the Metering group included in the total distribution Opex forecasts for the next regulatory period, as well as actual and forecast expenditures for the current regulatory period is shown in Table 8-10.

Table 8-10 – Distribution metering actual and forecast expenditures including cost escalation ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Metering (M)	20.11	19.23	15.90	20.21	24.46	29.07

Figure 8-8 – Distribution metering expenditure ($M)



8.2.9 Opex

Non recurrent distribution operational expenditures include four projects:

1) Demand Side Management (DSM) projects,
2) Energy Solution projects
3) Field Survey Information Capture project,
4) Training new contractors and staff, and
5) Distribution automation – sequence switching

Each of these projects is described and cost estimates provided in the following sub sections.

Demand-side management

Western Power is required to consider alternative options in the development of network capacity augmentation plans as part of its regulatory obligations under the Code. The alternative options include, amongst others, the use of embedded generation and demand side management. Western Power has developed a series of ten discrete projects in order to build up a knowledge base regarding demand side management **(DSM)** options, their effectiveness and associated implementation costs. This knowledge base would enable network planners to carry out technical and financial analysis to determine the viability of DSM options compared to the traditional poles and wires options.

The projects included in the DSM non recurrent Opex forecasts have been selected to determine:

- the possibility of integrating direct load control technology into Western Power's existing technology infrastructure
- the effectiveness of direct load control in terms of reducing peak demand on constrained feeders
- the willingness of customers to participate in direct load control programs and whether incentives are required and to what extent in order to promote participation
- the cost of demand reduction on a per customer and per kW basis to facilitate cost/benefit analysis of DSM compared with network augmentation
- the extent of business process re-engineering required to incorporate direct load control capability within Western Power, and
- the critical issues and potential solutions associated with the potential widespread roll out of demand side management initiatives.

Table 8-11 details the proposed forecast expenditure profile over the next regulatory period and which is included in the total distribution Opex forecasts.

Table 8-11 – Demand-side management forecast operational expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Domestic sector A/C load control	1.09	1.00	0	2.09
Energy efficient homes	1.09	1.00	0	2.09
DSM commercial activities	0.66	0.67	0.68	2.01
DSM tariffs	0.44	0.44	0.46	1.34
Thermal energy large scale storage	0.66	0.09	0	0.75
Hot water curtailment	0.49	0.06	0	0.55
Retail sector A/C load control	0.22	0.08	0	0.3
Heat pump hot water systems	0.22	0.06	0	0.28
Education sector A/C load control	0.08	0.03	0	0.11
Thermal energy storage	0.08	0	0	0.08
Total ($M)	**5.03**	**3.43**	**1.14**	**9.60**

Energy Solutions Research and Development[106]

One strategy of Western Power is to become an energy solutions business, in order to run the business more efficiently and offer more flexible and cost effective solutions to customers. In order to achieve this goal Western Power needs to investigate and invest in alternative and emerging technologies.

This program covers feasibility investigations and the development of innovative electrical engineering solutions including:

- advanced techniques for measuring peak reductions and efficiency savings
- advanced technology for power grid sensing, communications, analysis and power flow control
- low carbon generation (distributed generation) which removes the need for additional poles and wires infrastructure etc enabling Capex deferral and significant environmental gains
- wide-area measurement and control networks including data mining, visualization, advanced computing, and communications in a highly distributed environment
- new reliability techniques, including communications network capabilities relating to outage and blackout scenarios
- research into customer behavior modification and energy efficiency education.

[106] Activity template DMS4790907 provides further detail on this category of work, which is anticipated to play and increasingly significant role in the Western Power of the future.

Table 8-12 – Energy Solutions R&D forecast operational expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Energy Solutions ($M)	5.46	5.55	5.69	16.70

Field survey information capture

There are currently many legacy distribution data quality issues that require field verification and cleansing to render the information useful. These include:

- pole verification – there are poles shown in the GIS that do not exist in the field
- transformer stock code verification – current transformers have unknown stock codes resulting in missing rating information which affects network planning usability of data
- recloser data – reclosers are shown without attributes such as protection settings again affecting network planning usability of data
- asset carrier codes – HV conductors are shown without conductor type and size which affects network planning usability of data
- phasing – unknown HV phasing information, particularly on spur lines, which affects operational decisions such as load balancing.

Correct and reliable asset data forms the basis of modern asset management techniques and would facilitate data mining to enable accurate identification of issues such as:

- long spans which can be responsible for starting bushfires by enabling conductor clashing, and
- assets likely to cause pole top fires.

Accurate asset spatial information and asset data enables:

- improved network planning and asset maintenance
- reduction in response times for unplanned outages – experience in South Australia following a similar data capture and verification program indicated substantial reductions in SAIDI, SAIFI and CAIDI and a corresponding reduction in GSL[107] payments to affected customers
- reduction in multiple site visits to verify information particularly when work is bundled for outsourcing to accredited contractors
- reduces new project design times if the data bases are known to be accurate.

[107] Guaranteed Service Level

Table 8-13 details the forecast expenditure profile for the field survey information capture project over the next regulatory period that has been included in the total distribution Opex.

Table 8-13 – Field survey information capture forecast operational expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Information capture ($M)	2.00	6.09	6.25	14.34

Staff and contractor training

This cost category relates to the training of new internal staff and new contractors. The majority of the training is associated with the delivery of the distribution Opex works program.

The training costs are distributed approximately 70% to external contractors and 30% new Western Power staff. Table 8-14 shows the forecast operational expenditures for training included in the total distribution Opex forecasts.

Table 8-14 – Staff and contractor training forecast operational expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Training ($M)	9.62	10.28	9.83	29.73

Distribution automation –sequence switching

This component of the work program involves the implementation of ENMAC logic scripts to distribution automation equipment. Under fault conditions these scripts will carry out a series of system interrogative checks and if certain criteria are met, will initiate automatic network sequence switching events.

These switching scripts will result in faster supply restoration times for the number of customers affected by a fault and thus achieve “self-healing” networks that will consistently ensure a high level of network reliability performance is maintained independent of human operator response times or availability.

Throughout the regulatory period, operating expenditure is required to maintain the scripts due to network reconfigurations.

Table 8-15 – Sequence switching script maintenance forecast operational expenditures including cost escalation ($M)

Item	09/10	10/11	11/12	Total
Distribution automation ($M)	0.14	0.14	0.15	0.43

8.2.10 Reliability-driven maintenance

Reliability-driven maintenance is specifically targeted at improving network reliability, and consists primarily of pole top inspections and line patrols.

These inspections and line patrols are primarily designed to increase the reliability of the distribution network by identifying conditions that impact on the SWIS SAIDI, SAIFI and CAIDI. They are used to identify the new worst performing feeders and follow through on the maintenance works identified during the 40 worst feeder program.

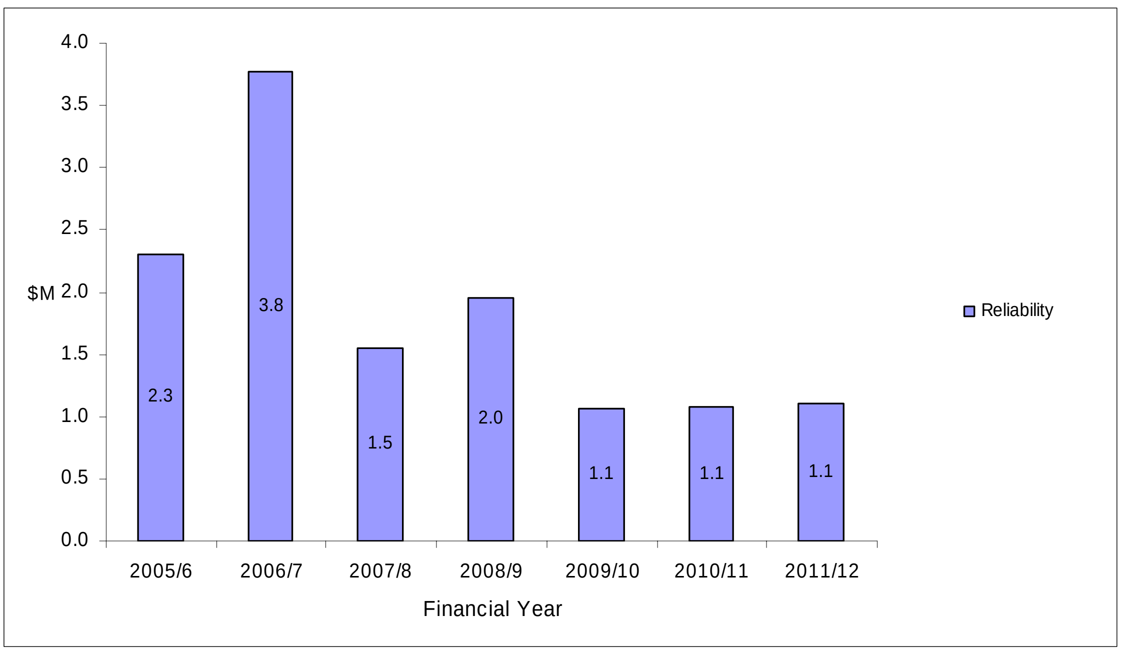
The inspections consist of line assessments for the targeted reliability reinforcement program, line inspections for the targeted maintenance program and line patrols for the recurring circuit breaker/recloser trip management program. Remediation works resulting from the inspections include pole maintenance, lightning mitigation and wildlife proofing.

The annual forecast expenditures for Pole Top Inspections and Line Patrols over the next three year regulatory period is $974k.

Table 8-16 – Reliability driven maintenance including cost escalation (M).

Item	06/07	07/08	08/09	09/10	10/11	11/12
Reliability-driven maintenance ($M)	3.77	1.54	1.95	1.06	1.08	1.11

Figure 8-9 – Distribution reliability expenditure ($M)



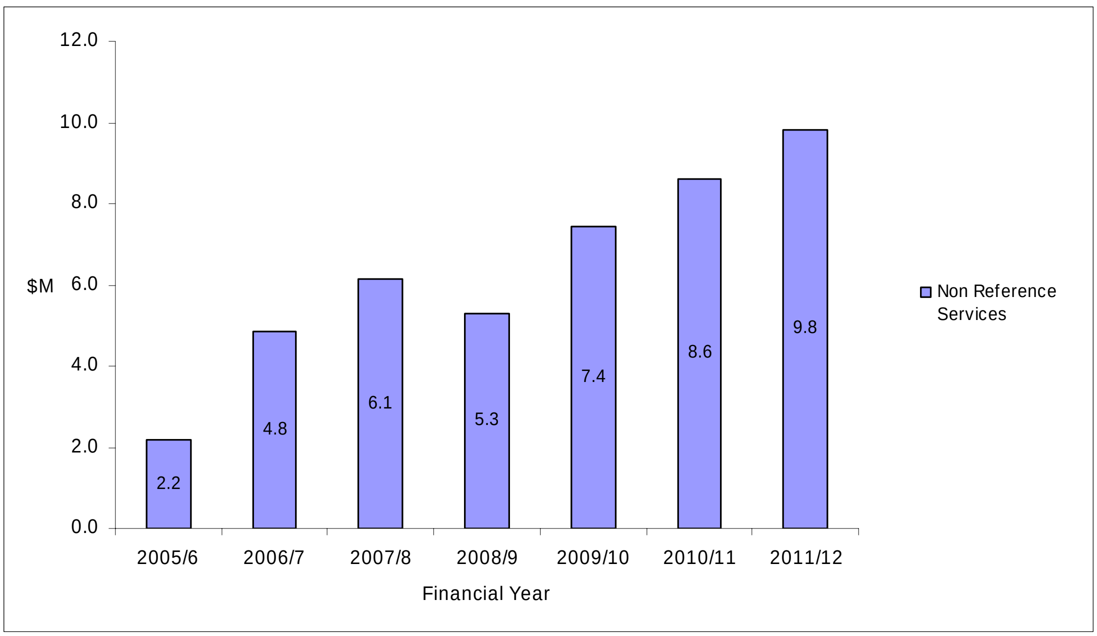
8.2.11 Non Reference Services (NRS)

The expenditure for the miscellaneous support services covered by NRS has increased significantly, particularly for activities impacted by the high level of state economic activity – for example the relocation of incumbent assets for industrial, commercial and residential land and property developments.

Table 8-17 – Comparison of distribution actual and forecast Non Reference Services expenditures ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12
Non Reference Services	4.84	6.13	5.30	7.42	8.61	9.82

Figure 8-10 – Distribution non reference services expenditure ($M)



8.3 Labour and material escalators

Western Power has commissioned independent expert[108] to provide forecast real increases in wages for WA Utility Workers and materials for distribution and transmission operating and capital works. Table 8-18 details their recommendations in relation to WA utility workers and distribution operating materials. Western Power has supplied details of a typical bundle of operating materials to assist in the calculation of the real escalation for distribution operating materials.

[108] Access Economics, 2008, *Material and Labour Cost Escalation Factors*, DMS 4575552

Table 8-18 – Independent expert forecast of cost escalators

Item	07/08	08/09	09/10	10/11	11/12
WA utility workers wage escalation	5.84%	4.92%	4.54%	4.12%	4.78%
Distribution operating Materials	3.87%	9.13%	2.98%	1.04%	5.83%

Source: Access Economics

In addition, Western Power's HR Group has advised that current negotiations for an enterprise agreement for internal staff should result in real wage escalation for internal labour as detailed in Table 8-19.

Table 8-19 – Western Power forecast escalation for internal labour

Item	07/08	08/09	09/10	10/11	11/12
Western Power real labour escalation	5.00%	6.50%	6.00%	6.00%	5.50%

Source: Western Power

As stated previously the cost estimates produced by the distribution estimating group do not include any real labour, contract services and material cost escalation, nor do they include any contingencies. Cost escalation has been included in the distribution operating forecasts at a cost category level rather than on a global level to facilitate comparison of forecasts with current regulatory period actual and forecasts. This is accomplished in an Opex model by developing composite cost escalators for each major Opex category based on the proportion of internal labour, contract services and materials in each category.

The Western Power distribution Opex model is also used to incorporate the impacts of the growth in assets under management during the next regulatory period resulting from the planned growth capital works. In addition the impact of the proposed refurbishment/replacement Capex on forecast Opex is calculated in the Opex model. Cost and asset escalation has been included in the transmission operating forecasts at a cost category level rather than on a global level to facilitate comparison of forecasts with current regulatory period actual and forecast expenditures.

8.4 Additional distribution assets constructed during next regulatory period

Western Power has used the magnitude of the proposed growth related levels of Capex to determine the additional Opex required to manage these additional assets. In the distribution Opex model the ratio of distribution growth related capital expenditure to the current Western Power transmission asset base replacement cost is calculated on an annual basis with the proposed capital expenditure compounded year on year. The resulting annual ratios are then reduced by 22% to compensate based on the fact that no condition maintenance expenditures are expected to be incurred by these new assets over the next regulatory period.

These calculations are detailed in the distribution Opex model and are applied in conjunction with the escalation resulting from the forecast real increases in internal labour, contract services and materials.

The total growth related forecast capital expenditure includes components of capital expenditure which do not result in additional network assets requiring operation and maintenance effort. This expenditure has been removed from the total growth related capital expenditure forecasts for these calculations

The forecast distribution growth related capital expenditures used as the dividend in these calculations are detailed in the following Table 8-20.

Table 8-20 – Distribution growth related capital expenditure ($M)

Item	09/10	10/11	11/12
Growth Capex	324.86	342.25	358.38

Western Power has calculated the current replacement cost of its distribution network assets to be $19.99B and this number has been used when calculating the ratio of future growth related capital expenditure to the current replacement cost of the distribution network asset base. The replacement cost is based on current construction costs and includes Western Power's costs such as easement acquisition, design, construction and commissioning costs, etc.

8.5 Opex/Capex trade off

Western Power has incorporated a trade off in forecast distribution operational expenditures resulting from the proposed asset replacement /refurbishment capital expenditure over the next regulatory period. It is widely acknowledged that replacing or refurbishing assets at or near the end of their operational lives results in reduced Opex.

The reduction primarily relates to avoidance of condition maintenance works as new assets do not require any condition maintenance expenditure over the next regulatory period. This reduction has been estimated to be 22% of the costs of maintaining and operating assets with approximately half their service lives remaining. This is the ratio used by Western Power in the Opex model to estimate that Opex savings resulting from the proposed replacement/refurbishment capital expenditure. The reductions in asset related Opex is calculated on an annual basis and total annual forecast Opex is reduced accordingly.

The forecast annual refurbishment/replacement capital expenditures used as the dividend in these calculations are detailed in Table 8-21.

Table 8-21 – Distribution replacement/refurbishment capital expenditure ($M)

Item	09/10	10/11	11/12
Replace/refurbishment Capex	299.08	337.76	410.75

Western Power has calculated the current replacement cost of its distribution network assets to be $19.99B and this number has been used in calculating the ratio of future refurbishment/replacement capital expenditure to the current replacement cost of the distribution network asset base. The replacement cost is based on current construction costs and includes Western Power's costs such as easement acquisition, design, construction and commissioning costs, etc.

8.6 Total forecast distribution operational expenditure

The total distribution operating expenditure forecast for the next regulatory period is shown in Table 8-22, including:

- the impacts of labour, contract services and material escalations expected over the period
- the impact on Opex of growth related distribution Capex
- the Opex trade off expected from the proposed distribution replacement/ refurbishment Capex, and
- including the proposed non recurrent Opex programs.

Table 8-22 – Forecast distribution Opex including cost and asset escalation but excluding corporate costs ($M)

Item	09/10	10/11	11/12	Total
Distribution Opex	317.41	337.77	355.57	1010.75

The total forecast distribution operational expenditure for the next three year regulatory period represents a real increase of approximately 73% over the total actual and forecast expenditures of the current regulatory period. The significant increase relates to substantial increases in preventative routine and condition maintenance and associated support functions, four additional non recurrent distribution Opex projects, and significant cost uplifts.

As discussed throughout this section on distribution Opex, Western Power has carried out a detailed review of all the maintenance operations, aligning them with the asset mission statements, and this combined with the forecast asset quantities as at the 2009/10 financial year has underpinned the estimates included in this submission.

Western Power believes that implementing this proposed distribution Opex works program will improve network performance, reduce unplanned asset failures – as well as eventually reducing corrective maintenance and call centre costs. There is a lag between commencing these additional maintenance works and achieving the expected outcomes and Western Power believes this will occur after the next regulatory period, i.e. in the 2012/13 financial year, and hence no reductions have been factored into the next regulatory period distribution Opex forecasts.