EnergyAustralia
We're on it

Regulatory Proposal

JUNE 2008


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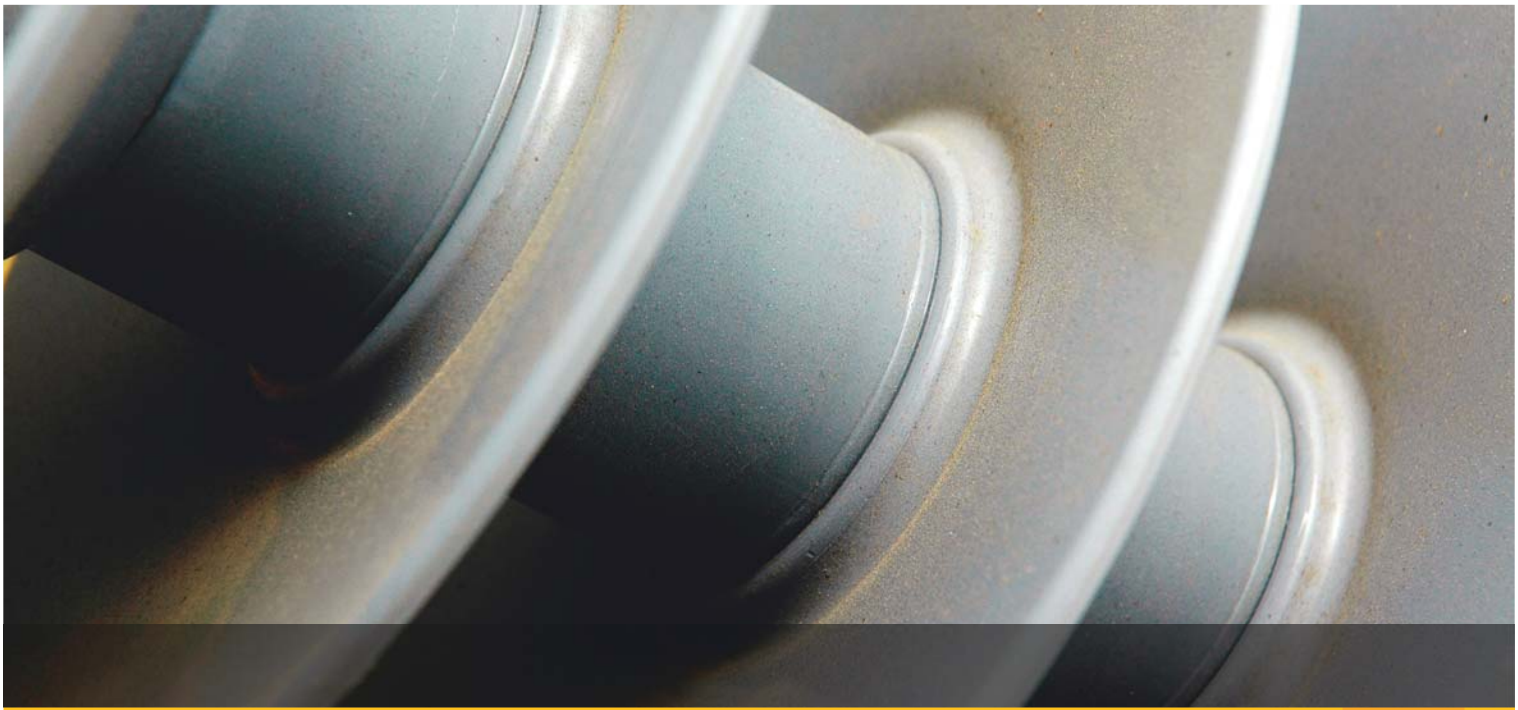
Contents



Overview and Outline

EnergyAustralia will invest $8.66 billion between 2009-14 to meet our obligations in providing a quality network service to our customers. The distribution component of customer energy bills will rise as a result of this investment program. A typical household customer is likely to see a first year increase on their total energy bill of around 14 percent or $2 per week.[i]

1.1 Introduction

EnergyAustralia operates the largest distribution network in Australia, which services 1.57 million customers. EnergyAustralia also owns and operates a transmission support network (as a distribution business), which is in the same order of size and value as the transmission networks in South Australia and Tasmania.

1.2 The EnergyAustralia network

EnergyAustralia provides electricity network services to Sydney City, Newcastle City and ports, the Hunter and Central Coast mining, wine and tourism area and surrounding urban, agricultural and coastal areas.

EnergyAustralia's customers include Australia's largest industrial customers, CBD, urban, rural and remote customers.

The depreciated network asset base at 1 July 2007 is $6.4 billion and is forecast to be $8.2 billion at the start of the next regulatory control period, 1 July 2009. The current replacement cost of the network system assets is estimated to be in the order of $30-35 billion. EnergyAustralia's network delivers approximately 50 percent of consumed electricity in NSW.

EnergyAustralia's network is the oldest in Australia. The network grew rapidly during the suburban expansion of the 1960's and 1970's.

The 1980's and 1990's were characterised by a slowdown in network growth as demand could largely be met with existing capacity through increased utilisation and risk management.

Management strategy and regulatory incentives were driven by the goals of increased asset utilisation and keeping down consumer prices.

EnergyAustralia's network is now highly loaded in some geographies and in some of the distribution network segments.

The result is a network with approximately 11 percent of assets that currently experience loading outside the criteria as set in the Design, Reliability and Performance (DRP) licence conditions, and on average 11 percent of zone substations and subtransmission substations are older than designed life.

EnergyAustralia's capital expenditure forecast is therefore determined by the condition assessment of the network, forecast load growth together with high levels of utilisation within the DRP licence conditions for security and capacity.

1.3 Legacy of previous regulatory decisions

A large proportion of the initial price increase for customers in the 2009-14 period is a legacy of regulatory decisions in the 2004-09 regulatory period as shown in Figure 1.1.

Determinations of EnergyAustralia's network revenue have historically been characterised by:

- over-emphasis on "X" cost control factors. The incentives have been strongly directed to ensure that the prices for network services are efficient, with little regard to service outcomes;
- over-emphasis on high capital utilisation without recognition of the run-away risk when utilisation approaches theoretical maximum levels; and
- a regulatory allowance for asset replacement programs below what EnergyAustralia proposed. The Independent Pricing and Regulatory Tribunal of NSW (IPART) and the Australian Competition and Consumer Commission (ACCC) both reduced EnergyAustralia's proposed asset replacement programs for 2004-09. In determinations to date, regulators have failed to understand the need for sustainable renewal programs. Replacing aged network elements which are highly loaded takes many years and is required to avoid long and frequent interruptions to customers.

i A typical EnergyAustralia household customer consumes 4.7 megawatt hours per annum.

Overview and outline (continued)

EnergyAustralia has not responded to the "CPI-X" incentives regime by reducing operating or capital expenditure to unsustainable levels. Rather, it has maintained expenditure at the minimum level required to maintain the network and maintain service standards. Operating expenditure in 2004-09 is forecast to be 15.7 percent above regulatory allowance. Capital expenditure is forecast to be 23.6 percent above the regulatory allowance.

In 2005, the NSW Government recognised the shortcomings in the "regulatory bargain", that had effectively emerged from past Determinations, and introduced licence conditions that encompass mandatory investment criteria and minimum service quality standards. These are known as the DRP licence conditions. This proposal outlines the expenditure necessary to deliver these asset security and service reliability licence conditions.

1.4 The key challenges for 2009-14

EnergyAustralia's proposal for 2009-14 addresses the following key challenges:

Disconnect between energy consumption and summer peak demand growth

On a weather corrected basis, EnergyAustralia has in the past five to 10 years observed a marked differential between growth in annual energy consumption and summer peak demand. This growth disconnect is not unique to EnergyAustralia, and is being or has been experienced by other DNSPs throughout NSW, Australia and the rest of the developed world. The key driver of this growth disconnect has been the recent rapid increase in the penetration of residential air conditioning appliances, which has a disproportionately greater impact on summer peak demand than on annual energy consumption. Residential air conditioning penetration in the EnergyAustralia network region is estimated to be 59 percent by June 2008, well behind NSW state estimates and the southern states of Australia. Over the period 2009-14 this proposal projects energy consumption growth of 1.6 percent per annum and summer peak demand growth of 2.8 percent per annum, reflecting an expectation that recent growth relativities will continue.

Mandatory DRP licence conditions

EnergyAustralia is required to meet conditions relating to reliability performance to comply with its Distribution Network Service Provider (DNSP) licence under the Electricity Supply Act 1995. There are three types of conditions:

(a) Design planning criteria

These criteria require EnergyAustralia to provide capacity within the network with an appropriate level of security (N, N-1 or N-2). EnergyAustralia's distribution network requires additional capacity to meet these conditions in some locations and network segments.

These licence conditions must be achieved for all existing assets by 2014 which effectively brings forward some future investment in capacity into the 2009-14 period.

Figure 1.1: Waterfall showing contributions of IPART decision to distribution P-nought ($m nominal)

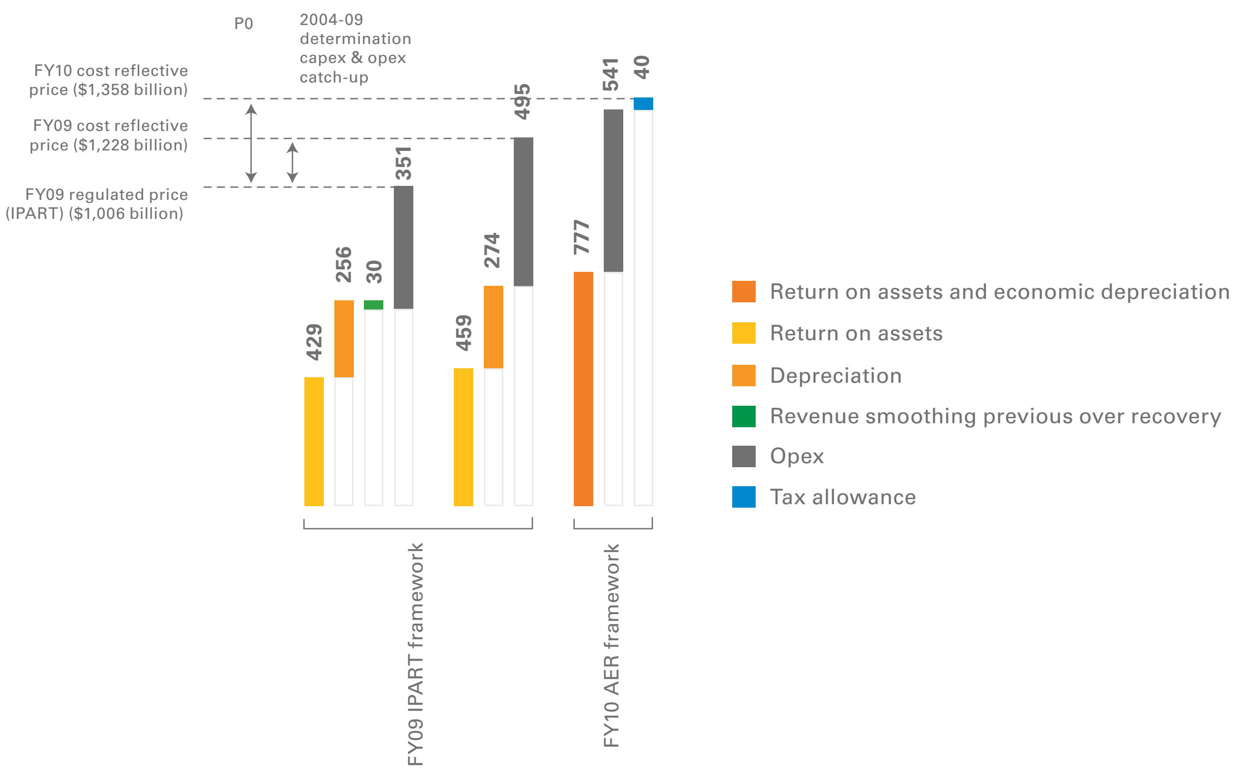
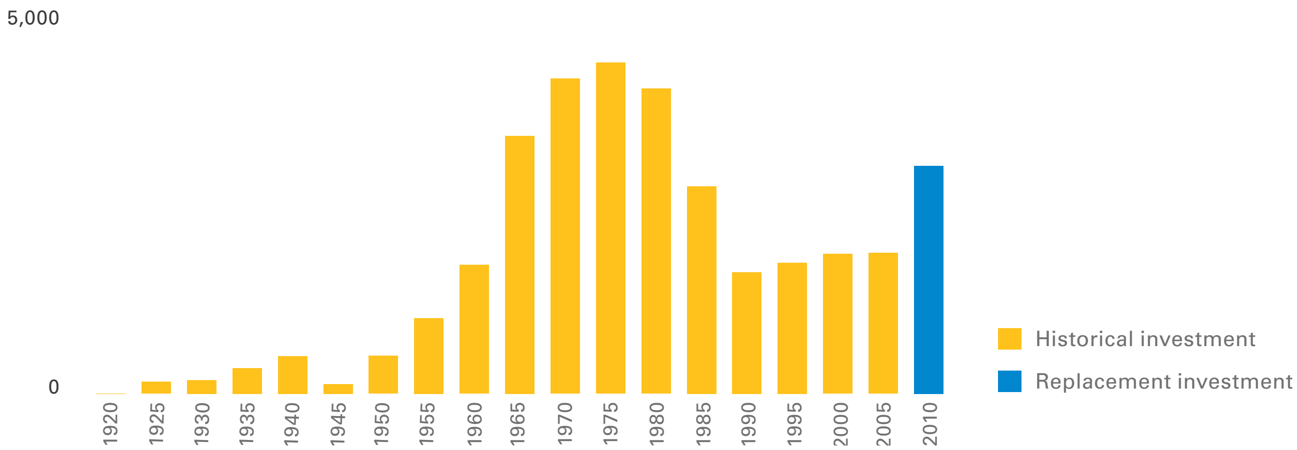


Figure 1.2: System asset age profile – replacement cost (FY09 $m real)



Overview and outline (continued)

(b) Reliability and individual feeder performance standards

These establish EnergyAustralia's minimum average reliability targets (SAIDI and SAIFI) by feeder type and reliability targets for each individual feeder. Some of EnergyAustralia's feeders are not currently meeting this condition.

(c) Customer service standards

These provide financial recognition to customers who have experienced poor reliability.

In addition to these mandatory licence conditions, there are a variety of other legal obligations that are considered by our teams in developing compliance and customer outcomes.

The capital and operating expenditures in this proposal have been developed to ensure EnergyAustralia complies fully with all safety, network management, design and performance obligations mandated by our licence conditions.

Network age profile – Old assets in service

A large proportion of the network was built between 1965 and 1980 and its age is therefore approaching or above 40 years old (Figure 1.2). Asset replacement is generally planned on condition and performance criteria. However, a high proportion of aged assets can present a substantial risk to the reliability and performance of the network before conditional or functional failure occurs.

On 30 June 2007, 11 percent (on a value basis) of our network assets were older than their designed technical lives. While prudent management and condition monitoring enables many asset types to remain in service beyond their original design life, this proposal includes the prioritised replacement of some assets on a condition basis as follows:

- When EnergyAustralia faces the risk that the failure rate for an asset category could overtake our capacity to respond to those failures with severe impacts on network performance in future periods.
- Replacement of asset types is based on condition although for those in service with high load (i.e. high utilisation) replacement is only possible in the autumn and spring low-load months. These replacement programs therefore take many years to execute and are programmed according to a target end-date.

This proposal addresses these emerging risks and achieves a reversal in the ageing trend in the transmission and subtransmission parts of our network. The distribution assets will continue to age, but at an acceptable rate.

1.5 EnergyAustralia's network development process

EnergyAustralia's proposal reflects the following business and management processes:

Planning process

EnergyAustralia's network planning processes are described in Chapter 5 of the Building Block Proposal (Part I). In summary, the process involves forecasts of load growth and new customer connections along with information on the load, condition and performance of in-service assets to develop investment plans. The process involves the development of:

(a) Area Plans – for the transmission and subtransmission network, which include investment for new capacity and investment to replace those assets where replacement is significant enough to trigger the opportunity to enhance capacity (i.e. 132kV oil filled cables, 33kV gas filled cables and 11kV switchgear).

There are 25 separate geographic subtransmission Area Plans. Each network substation is assessed for its capability to meet the DRP licence conditions, its condition, its reliability performance and the forecast future customer connections. This integrated replacement and growth methodology results in network investment plans that are efficient and maximise synergies.

(b) A 15 year program for asset replacement based on condition based monitoring and failure data. The replacement program considers the risk and consequence of failure, asset sustainability, population size and the availability of technology and spares. The program applies a consistent methodology and predicts requirements into the future. Importantly, the program explains when and why programs of replacement are best undertaken on a reactive basis or by proactive replacement.

(c) Separate strategic investment plans that focus on single investment drivers for the distribution network. The component focussed nature of these plans lends itself to a risk portfolio approach to optimise maintenance and replacement costs. These comprise:

- a Reliability Investment Plan (for poorly performing assets);
- Duty of Care Plan (for non-system asset elements such as asbestos removal, oil containment, fire stopping);
- a Customer Connections Plan for connection assets;
- an 11kV Capacity Plan;
- a Low Voltage Capacity Plan; and
- System and Business Support Plans.

Forecasting methodology

Demand growth forecasts are a key driver to the planning processes. EnergyAustralia prepares:

- global forecasts of peak demand and annual energy consumption for normal weather conditions; and
- spatial forecasts of the peak demand growth and installed capacity of substations and feeders to predict capacity constraints and identify triggers to investment decisions.

Chapter 4 of Part I (Building Block Proposal) explains the forecast of expected peak demand at each zone and subtransmission substation which are based on:

- historical trends of peak demand growth, both at the location and across the network;
- committed increases in demand for capacity in the area (new connections or other increases in spot load); and
- known load transfers.

Detailed forecasts are in Attachments 13.2 Energy and Global Peak Demand Forecasts to 2014 and Attachment 4.7 Annual Electricity System Development Review (AESDR) 2006/07 and 2007/08.

This proposal assumes average energy consumption growth of 1.6 percent per annum, average summer peak energy demand growth of 2.8 percent per annum and allows for spatial peak demand growth forecasts where appropriate.

Capital governance

Capital governance is the internal process that is applied after the regulatory determination to confirm that a project is still prudent and efficient.

EnergyAustralia has a capital governance procedure for authorisation of specific programs or projects within the investment program.

This process ensures that individual investments are not made until:

- the need for investment has been demonstrated, based on capacity and condition criteria, and authorised by the relevant officer or the Board;
- the alternatives, including options which would defer or replace capital expenditure, have been properly assessed; and
- the costs of the proposed solution are efficient and are costs which a prudent network service provider would require to achieve the solution.

1.6 Summary of proposal

EnergyAustralia's total revenue requirement, to meet the various challenges in the next regulatory control period is $10.01 billion over five years.

Capital expenditure forecast

The capital requirement for 2009-14 is $8.66 billion[1] comprised as follows:

- transmission investment of $443 million for additional capacity to meet demand growth and replacement needs;
- Sydney CBD Area Plan of $612 million for two new zone substations and increased downstream capacity;
- other Area Plans of $2,894 million for 42 new zone substations, and retirement of 32 zone substations;
- Replacement Plan of $1,828 million for components of the transmission and substation network not included in the Area Plans above and all distribution network replacement;

1 Figures quoted are 2008-09 dollars in real terms

Overview and outline (continued)

- Customer Connection investments of $504 million;
- increased capacity in the 11kV system of $698 million to restore capacity in line with the DRP licence conditions;
- increased capacity in the low voltage system of $295 million;
- Duty of Care plan to upgrade key elements to modern standards of $285 million;
- rectification of specific reliability hot spots of $79 million; and
- other business support investments of $1,020 million.

Operating expenditure forecast

Operating expenditure for the period is forecast to be $2.97 billion (FY09 real). This incorporates the significant impacts of:

- increased workload largely arising from the larger asset base, adding approximately 25 percent to direct maintenance costs;
- increased workload due to the weighted average age of the asset base increasing, i.e. where there is a higher proportion of assets in some asset types that are at an age which requires more preventative and corrective maintenance;
- cost increase based on the Competition Economics Group (CEG) recommendation for real escalation factors for labour and input materials for the electricity supply sector; and
- step changes partly arising from the higher costs of IT for the introduction of new asset management systems and partly arising from our response to meeting obligations.

Justification overview

In order to meet all its capital expenditure objectives, EnergyAustralia must:

- replace ageing assets, where the risk of failure is increasing beyond an acceptable level, and begin to address the catch-up required from low levels of replacement expenditure in the past. This proposal renews approximately 10 percent of our assets. The largest category of expenditure is $963 million on distribution mains, which will replace six percent of assets in this category;
- replace a significant proportion of compound filled 11kV switchgear, 33kV gas cables and 132kV oil-filled cables during the period, which will improve the transmission and subtransmission network security;
- provide connection to a third inner metropolitan 330kV feeder and Bulk Supply Point (BSP) for secure supply to the Sydney CBD and upgrade the CBD with two new zone substations (a 40 percent increase) to meet load growth and the N-2 design criteria licence condition;
- upgrade and replace 30 zone substations to meet load growth and provide the additional capacity to meet the N-1 design criteria licence condition; and
- increase the capacity of the 11kV network and the low voltage system to meet the licence criteria and to meet demand.

The operating cost increase in the next period is consistent with the growth in the size of the network, cost escalations and step changes required for new obligations and management systems.

Network innovation

EnergyAustralia's Regulatory Proposal includes investments to establish a platform for an "intelligent" network.

During the 2004-09 period, EnergyAustralia has deployed an optical fibre communications network to the zone substation level and researched new technologies to improve operational efficiency.

This proposal includes investment to improve connectivity and upgrade the Supervisory Control and Data Acquisition (SCADA) systems. It also includes installation of smart devices for distribution monitoring and control to improve the performance of the 11kV network (targeting the worst performing areas). We are also proposing to invest in strategic pricing studies and advanced metering trials.

1.7 Outcomes and benefits

The following outcomes are targeted by this proposal:

- meeting the mandatory design criteria will ensure improved reliability and provide greater security of supply;
- meeting the reliability targets in the licence conditions through secure redundancy and asset condition;
- meeting the demand for new connections;
- providing an effective response to customer's expectations for new products, in particular demand management products and distributed generation; and
- delivering customers the benefits of operating and capital efficiency gains available from new communications, automation and control technologies employed on the network.

Consequences of under-investment

EnergyAustralia submits that it has undertaken sufficient investigation in developing this proposal to be confident that:

- All capacity related investment is required to meet the mandated licence conditions.
- Any reduction in investment in capacity or replacement (from that proposed) would be likely to result in failure to meet mandatory reliability and performance standards.
- Any reduction in replacement expenditure would not address the existing backlog and would allow the proportion of assets over technical design age to increase resulting in unacceptable risk in future periods.
- Failure to invest as proposed in network communications technologies and control technologies would reduce operating efficiencies in the network and would result in higher costs in the long term.
- There are limited deferral options in this capital proposal due to the current state of the network and the high degree of asset utilisation.
- The available low-load "windows of opportunity" when equipment can be taken out of service have been utilised to the maximum extent possible, to ensure costs are minimised and risks in future periods are managed.

1.8 Strategies for delivery

EnergyAustralia's proposal is supported by delivery strategies and resource plans to carry out the proposed investment and maintenance work in the period including:

- Increased capability of EnergyAustralia staff. EnergyAustralia currently employs 5,400 staff; including the Retail Line of Business. Approximately 3,090 are employed directly on maintenance, construction and operations of the network. Initiatives to increase capability include standardised designs, use of advanced design software, network automation and deployment of mobile computing.
- Increased work undertaken by contractors. EnergyAustralia's established delivery capability is currently augmented by the Accredited Service Providers (ASPs) from the electricity supply industry market. Examples include contract cable laying, civil and building work, connection and contestable work.
- Establishment of Strategic Alliances. EnergyAustralia is in the process of establishing alliance agreements with private sector infrastructure providers for delivery of substation projects. This will involve increased use of design and construct, turn-key style contracts for fast delivery of capital works.

EnergyAustralia's proposal takes account of deliverability and the likely impact of cost escalation factors to ensure that the capital forecast is adequately scoped and costed.

Overview and outline (continued)

1.9 New regulatory challenges

Advanced metering infrastructure

This proposal does not include the cost of a network wide installation of Advanced Metering Infrastructure (AMI). However, the installation of AMI by DNSPs is likely to be mandated during the 2009-14 determination.

EnergyAustralia has already invested in technology trials and pricing options, but acknowledges that there are considerable functional and technical specification issues yet to be resolved. However, the issue is receiving wider industry engagement to address technology and operating risks associated with a large scale roll out. It is anticipated that the Ministerial Council on Energy (MCE) will make a policy decision following the cost benefit analysis being conducted by the Smart Meter Working Group.

Once a mandated roll out by DNSPs has been formally imposed, EnergyAustralia anticipates a pass-through mechanism and separate revenue allowance for the costs of the roll-out of smart meters which would need to cover the following cost components:

- development of the IT and back office systems to enable large scale testing;
- procurement and installation of AMI across the whole network; and
- ongoing operating costs of installed smart metering systems.

Business separation

The NSW Government has announced its intention to change the structure of the electricity industry in NSW and separate network and retail operations.

The costs of any business separation are not included in this proposal. EnergyAustralia proposes that a specific pass-through mechanism be established by the Australian Energy Regulator (AER) which would be triggered at the time the NSW Government implements its decision. EnergyAustralia recommends a pass-through mechanism which would need to cover the following additional costs:

- the initial costs of separation and establishing network-specific business capabilities; and
- business function costs changed by the business separation decision.

Innovation and research

EnergyAustralia commends the AER for promoting innovation in global demand management innovations (through a modest demand management innovation fund equivalent to 0.1 percent of revenue).

However, EnergyAustralia notes that the current regulatory arrangements discourage investment in research and innovation, unless the business has incorporated the programs in its expenditure forecasts. Innovations are uncertain by nature, because they depend on the development and adoption of new technology and therefore are unlikely to be predictable over a five year period.

EnergyAustralia notes the decline in network innovation since the introduction of "CPI-X" regulation in 1996.

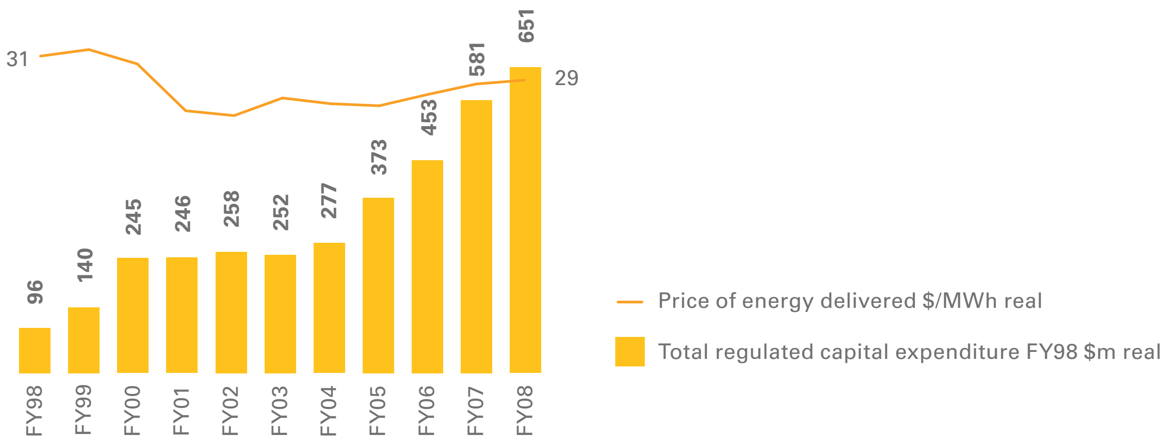
In response to similar circumstances, the UK regulator Ofgem has established an "I factor" mechanism, whereby businesses are encouraged to undertake research and development activities to ensure that efficiency of energy delivery is maximised. We would urge the AER to implement a meaningful innovation incentive as a modification to its existing innovation fund for demand management incentives.

1.10 Customer price implications

In real terms, the average price paid by EnergyAustralia customers for the use of our network is lower now than it was 10 years ago. In addition Figure 1.3 shows that the price path has not reflected the capital expenditure trend.

The result of the past distribution regulatory regime is that pricing has not kept pace with both capital and operating expenditure requirements. Had the actual costs incurred in the 2004-09 period been included in the price path, the price of Distribution Control Services at June 2009 would be 18.6 percent above the determined price. That is, a price adjustment of 18.6 percent is necessary just to rectify the legacy of previous regulatory decisions.

Figure 1.3: Total regulated capital expenditure versus price of energy delivered



EnergyAustralia expects the distribution component of a customer's energy bill to increase on average by 29.4 percent in the first year (not including CPI) followed by real increases of 10.4 percent in each year thereafter. A typical household customer is likely to see a first year increase on their total energy bill of around 14 percent or $2 per week.

The initial price rise sought is attributable to:

Legacy of past regulatory periods	18.6 percent
Change in market conditions affecting WACC (i.e. higher cost of debt)	4.3 percent
Planned investments and new operating costs	6.5 percent

1.11 Customer enablement

EnergyAustralia was the first utility in the world, that we are aware of, to introduce Time of Use (ToU) as the standard mandatory tariff for network charges. EnergyAustralia has installed over 400,000 meters and converted 200,000 of our largest residential and small business customers to time based tariffs. All larger users pay time based and capacity based tariffs.

We have made these investments to promote long-term behavioural change by customers. This is a responsible demand management strategy aimed at reducing future capital expenditure. We have undertaken this long-term strategy in response to an increasing divergence between growth in peak demand and energy consumption growth.

EnergyAustralia intends to continue to introduce time based pricing to its customers for all new and upgraded customer connections. However, the decision regarding AMI is imminent and EnergyAustralia has suspended our program to convert meters until that decision is made.

1.12 Structure of proposal

EnergyAustralia's Regulatory Proposal is comprised of this proposal document (in three parts), all appendices, supporting documentation and all other information submitted or made available to the AER.

EnergyAustralia's Regulatory Proposal has been prepared in accordance with the transitional provisions outlined in Chapter 11 and Appendix 1 of the National Electricity Rules. These provisions are referred to as the Transitional Rules throughout this proposal.

This Regulatory Proposal has been prepared to comply with the Rule requirements, relevant AER Guidelines and contains the information required by the AER's Regulatory Information Notice (RIN).

In accordance with Rule requirements, EnergyAustralia has included as Attachment 1.4 to this proposal, a document indicating which parts of the Regulatory Proposal EnergyAustralia claims are confidential.

How has this proposal been prepared and what procedure will the AER follow?

The new National Framework codifies many elements of the process for preparing a regulatory proposal and making a determination.

The Rules set out a series of determinations the AER must make which, when incorporated, form the distribution determination. The most material determination is that made in response to the Building Block Proposal.

Overview and outline (continued)

What services does this proposal cover?

EnergyAustralia's Regulatory Proposal Part II Service Classification and Control Mechanism Proposal, outlines our approach to the new service classifications.

The Building Block Proposal outlines EnergyAustralia's revenue requirement for all Standard Control Services as established in the Transitional Rules.

"Standard Control Services" are deemed to be:

- all services previously described by IPART in the current determination as Prescribed Distribution Services (in relation to Emergency Recoverable Works however, EnergyAustralia submits in Part II of the Proposal that these works are not distribution services); and
- services which in the absence of Transitional Rules would have been defined as Prescribed Transmission Services under Chapter 6A of the Rules.

Standard Control Services include those Direct Control Services which EnergyAustralia identifies as having negotiable components. Services which are not part of the Building Block Proposal include:

- "Alternative Control Services" which relate to EnergyAustralia's public lighting infrastructure;
- services which in the absence of Transitional Rules would have been classified as Negotiated Transmission Services – these are deemed to be a Negotiated Distribution Services and subject to negotiated distribution service criteria and negotiating framework; and
- services (other than those relating to public lighting infrastructure) which IPART classified as excluded services. These are deemed under the transitional framework to be unregulated and not subject to direct control providing EnergyAustralia complies with the Excluded Services Rule 2004/01. EnergyAustralia has sought to vary the classification of these services as part of this proposal.

Further information on the service classification, the proposed control mechanism and the proposed application of control mechanism to these services (with necessary supporting information) can be found in Part II of this proposal.

Focusing on constituent decisions

EnergyAustralia's proposal focuses on providing the necessary information for the AER to make its series of constituent decisions[2]. EnergyAustralia has broadly integrated the constituent decisions within the various components of the Regulatory Proposal. The structure of the Regulatory Proposal is as follows:

Part I: Building Block Proposal

EnergyAustralia's Building Block Proposal (Part 1 of the Regulatory Proposal) provides the necessary information to allow the AER to make constituent decisions on:

- the annual revenue requirement for each year of the regulatory control period (outlined in Chapter 1 of the Building Block Proposal);
- the regulatory asset base at the commencement of the regulatory control period (Chapter 2);
- whether to accept or not to accept the forecast capital expenditure for Standard Control Services (Chapters 3-6);
- whether to approve or not to approve the depreciation schedules (Chapter 7);
- the rate of return in accordance with Transitional Rule 6.5.2 (Chapter 8);
- whether to accept or not to accept the forecast operating expenditure for Standard Control Services (Chapter 9-11);

2 Transitional Rule 6.12.1 states that a distribution determination is predicated on a series of constituent decisions by the AER. In making a decision and subject to other parts of the Rules, 6.12.3 states that the AER has discretion to accept/approve or refuse to accept/approve any element of the Regulatory Proposal. If it refuses to accept an amount, value or methodology in the Regulatory Proposal, the substitute amount, value or methodology must be determined on the basis of the current Regulatory Proposal and amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

- the estimated cost of corporate income tax (Chapter 12);
- the control mechanism parameter (X factor) used for Standard Control Services (Chapter 13);
- how any applicable efficiency benefit sharing scheme, service target performance incentive scheme or demand management incentive scheme is to apply to EnergyAustralia (Chapter 14);
- whether depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure (Chapter 14); and
- additional pass through events that are to apply for the regulatory control period (Chapter 15).

Part II: Service Classification and Control Mechanism Proposal

EnergyAustralia's Service Classification and Control Mechanism Proposal provides the necessary information to allow the AER to make constituent decisions on:

- the classification of services provided by the DNSP over the regulatory control period (Chapters 1 and 2);
- which, if any, components of Direct Control Services are negotiable components (Chapter 3);
- the control mechanism for each of the Standard Control Services and how compliance with the mechanism is to be demonstrated (Chapters 4 and 5);
- the division of revenue between transmission and distribution[3] (Chapter 6); and
- the control mechanism for public lighting services and how compliance with the control mechanism is to be demonstrated (Chapter 7).

Where appropriate, EnergyAustralia has stated in its proposal reasons for the departure in approach from that recommended by the AER in a guideline or statement.

Part III: Pricing and Negotiating Frameworks Proposal

EnergyAustralia's Pricing and Negotiating Frameworks Proposal provides the necessary information to allow the AER to make constituent decisions on:

- procedures for assigning customers to tariff classes or reassigning customers from one tariff class to another (Chapter 1);
- how EnergyAustralia is to report to the AER on its recovery of Transmission Use of System charges (TUoS) for each year of the regulatory control period (Chapter 3);
- whether to approve or refuse to approve the proposed pricing methodology for EnergyAustralia's Prescribed (Transmission) Standard Control Services (Chapter 4); and
- any negotiating framework that is to apply for the regulatory control period and the negotiable component criteria and negotiated distribution service criteria that will apply (Chapter 5).

The principal elements of EnergyAustralia's Regulatory Proposal are set out in Table 1.

3 While not a constituent decision as such, the AER in its distribution determination divides the revenue calculated in Part III in to the respective portions attributable to distribution and transmission services (Transitional Rules 6.12.1A).

Overview and outline (continued)

Table 1: Principal elements of EnergyAustralia's regulatory proposal

Standard Control Services (Combined, Distribution and Transmission) Nominal, $billion	FY10	FY11	FY12	FY13	FY14
Capital expenditure forecast	1.62	1.69	2.02	2.02	2.00
Regulatory Asset Base	8.22	9.80	11.43	13.36	15.25
Revenue requirements					
Return on Capital	0.80	0.96	1.11	1.30	1.49
Return of Capital	0.08	0.10	0.13	0.15	0.15
Operating Expenditure	0.58	0.61	0.67	0.71	0.75
Tax	0.04	0.08	0.09	0.10	0.11
Annual Revenue Requirement	1.50	1.75	2.00	2.27	2.49
Forecast energy consumption (GWh)	31,565	32,084	32,554	32,835	33,234
Control mechanism X Factors (%)					
• Distribution	-29.41	-10.43	-10.43	-10.43	-10.43
(attributable to 2004-09 period)	-18.60				
• Transmission	-8.42	-15.77	-15.77	-15.77	-15.77

Price control mechanism arrangements:

- Transmission standard control services subject to Revenue Cap
- Distribution standard control services subject to Weighted Average Price Cap (WAPC)
- Miscellaneous and monopoly services to be revalued to reflect actual cost and included in distribution WAPC

Incentive mechanisms:

- Capital Expenditure – proposed low powered incentive
- Demand management – D Factor and innovation allowance
- Proposed "I Factor" for innovation in service delivery
- Efficiency Benefit Sharing Scheme - proposed to be refined in 2009-14
- Service Target Performance Incentive Scheme - proposed to be refined in 2009-14

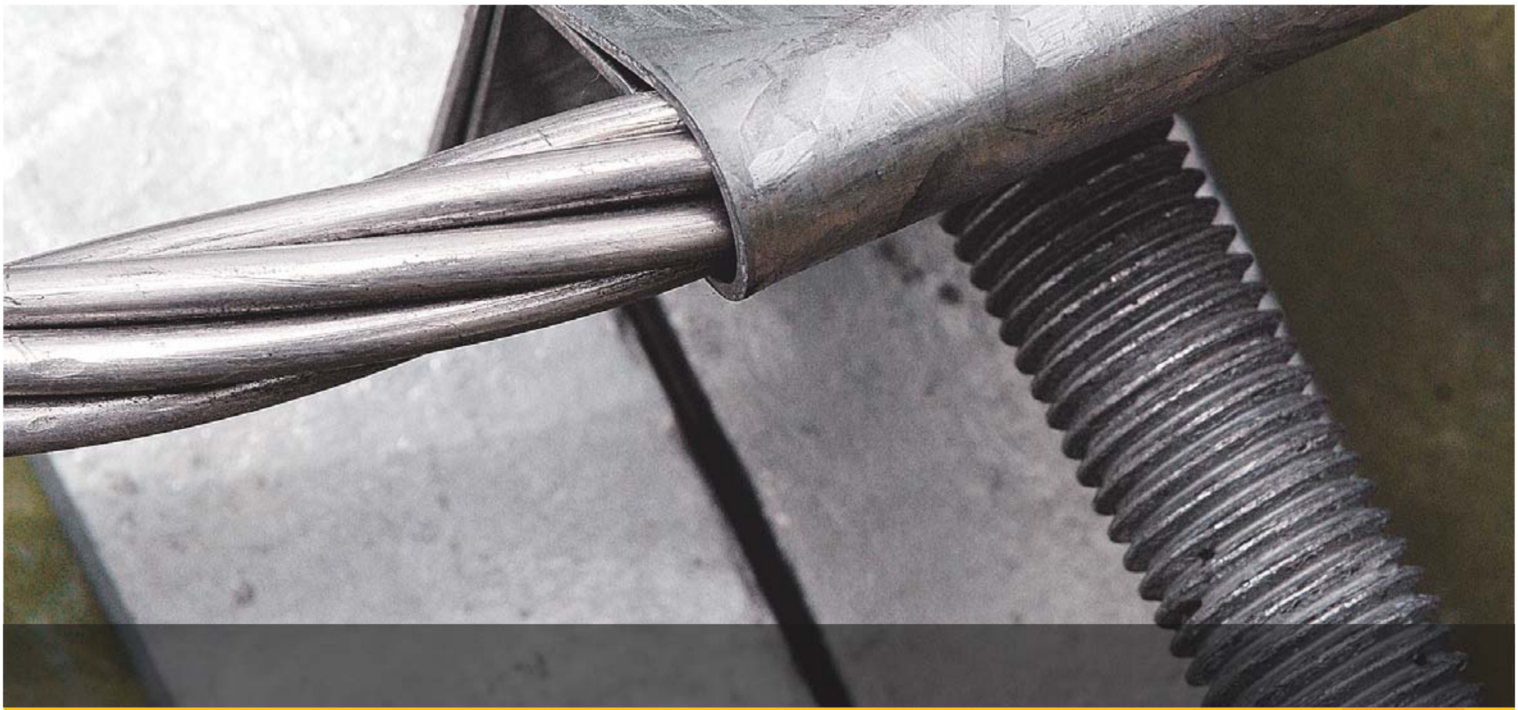
Proposed pass through events (in addition to Rules Chapter 10):

- Dead zone (ie. during 2008-09)
- Force Majeure
- Material cost or demand input variation
- Major change arising from Joint Planning with other NSPs
- Compliance obligations not covered by the NEL
- Major customer connections
- Separation of Retail business

Alternative Control Service
Public lighting
• Schedule of cost reflective prices, escalated by (CPI+1.9%)
• Maximum customer bill increase of CPI+11%

Services subject to a Negotiating Framework
• Negotiated Distribution Services
• Negotiated components of Direct Control Services

Other Services	
• Metering services (Types 1-4)	Proposed to be Unclassified
• Customer funded connections	Proposed to be Unclassified
• Customer specific	Proposed to be Unclassified



Regulatory Proposal part 1

Building Block Proposal June 2008

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OPEX

Introduction

EnergyAustralia's Building Block Proposal has been prepared in accordance with the Transitional Rules which apply to the NSW and ACT DNSPs for the 2009-14 period.

This part (Part I) of EnergyAustralia's Regulatory Proposal contains EnergyAustralia's Building Block Proposal for Standard Control Services. It provides for, and incorporates, the revenue requirements for Standard Control Services for the regulatory control period:

- commencing on 1 July 2009; and
- ending on 30 June 2014.

EnergyAustralia also provides other distribution services which are not part of this Building Block Proposal.

These include:

- services associated with **public lighting** which are explained in more detail in Part II of the Regulatory Proposal;
- services (other than public lighting) that were deemed to be **excluded services** in the 2004-09 regulatory control period. These services will either be unregulated or, with agreement of the AER, unclassified distribution services in the next regulatory control period; and
- **Negotiated Distribution Services** which are subject to a negotiating framework. EnergyAustralia's proposed negotiating framework is detailed in Part III of our Regulatory Proposal (Pricing and Negotiating Frameworks).

Part II of EnergyAustralia's Regulatory Proposal (Service Classification and Control Mechanism Proposal) provides detail of how our various services are classified for the purposes of the next regulatory control period.

EnergyAustralia's cost allocation method describes how costs are allocated to the various services EnergyAustralia provides. This Building Block Proposal includes costs that have been allocated to Standard Control Services in accordance with the cost allocation method. EnergyAustralia's cost allocation method has been used for the establishment of the following elements of the Building Block Proposal:

- Regulatory Asset Base (RAB);
- forecast capital expenditure;
- forecast operating expenditure; and
- estimated corporate income tax.

Furthermore, because EnergyAustralia's Standard Control Services incorporate costs of both its transmission and distribution networks, the cost allocation method is used to allocate aggregate revenues into transmission and distribution components for the purpose of establishing the control mechanism and prices.

EnergyAustralia's Building Block Proposal has been prepared in accordance with the post-tax revenue model (PTRM), the requirements of the Rules[1] and the requirements of the AER's Regulatory Information Notice (RIN)[2].

EnergyAustralia's Building Block Proposal is comprised of this Part, all appendices, supporting documentation and information, and all other relevant information submitted or made available to the AER.

Where necessary, EnergyAustralia has adapted the PTRM to allow it to meet the requirements of the Rules in respect of both the transmission and distribution networks.

The AER has produced the following instruments, guidelines, models and schemes which are relevant to EnergyAustralia's Building Block Proposal:

- the PTRM;
- the roll forward model (RFM);
- the guideline on control mechanisms for Direct Control Services;
- Efficiency Benefit Sharing Scheme;
- Service Target Performance Incentive Scheme; and
- Demand Management Incentive Scheme.

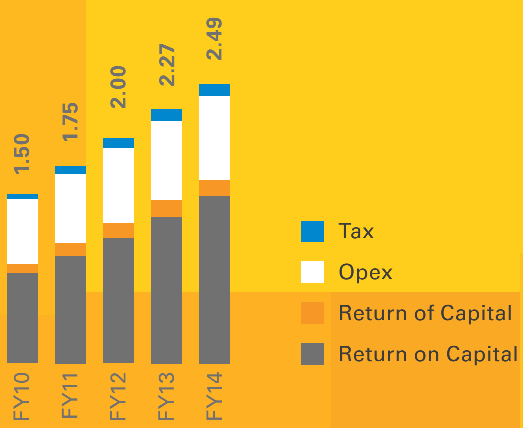
EnergyAustralia has used AER guidelines as a basis for its preparation of the Building Block Proposal. Where EnergyAustralia has considered it necessary to depart from AER guidelines, it notes the extent of the departure and the reasons.

1 In particular, Part B of and Schedule 6.1 of the Transitional Rules Chapter 6

2 Clause 6.3.1(c)

1. Annual revenue requirement

Figure 1.1: Building Block components of the annual revenue requirement ($bn nominal)



The purpose of this chapter is to identify:

- the annual revenue requirement (Standard Control Services) for each year of the regulatory control period and the total revenue requirement calculated in accordance with the Rule requirements; and
- the method that is likely to result in the best estimate of inflation, in particular the method for the annual adjustment of the RAB.

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(2), 6.12.3(d), 6.4.3(a))

The AER's determination is predicated on its decision to approve or refuse to approve EnergyAustralia's annual revenue requirement as set out in its Building Block Proposal.[3]

The AER must approve EnergyAustralia's total revenue requirement and the annual revenue requirement if satisfied those amounts:

(1) have been properly calculated using the PTRM; and

(2) on the basis of amounts calculated, determined or forecast with the requirements of Part C of Chapter 6.[4]

The annual revenue requirement for a Distribution Network Service Provider for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are[5]:

- indexation of the regulatory asset base;
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax;
- the revenue increments or decrements (if any) for that year (including those arising from the application of incentive schemes); and
- the forecast operating expenditure for that year.

1.1 Summary

The total revenue EnergyAustralia requires for the 2009-14 regulatory control period is $10.01 billion (nominal dollars).

This comprises the annual revenue requirement, by building block component, for each year of the regulatory control period as demonstrated in Figure 1.1.

1.2 Calculating the annual revenue requirement

The annual revenue requirement is for EnergyAustralia's Standard Control Services and has been calculated using:

- inputs to the building blocks outlined in Part C of the Rules;
- the PTRM and RFM; and
- indexation using a methodology consistent with the Rules.

The AER's completed PTRM (Attachment 1.1) and RFM (Attachment 1.2) are included as part of this Building Block Proposal. EnergyAustralia's demonstration of the application of the models in calculating the annual revenue requirement, including any assumptions made by EnergyAustralia in populating the model, are shown in the model itself. Total numbers in this Regulatory Proposal may not add up due to rounding.

1.3 Indexation of the asset base

The Rules provide specific guidance on the calculation of the RAB both between regulatory control periods and within the period. These are reflected in the RFM produced by the AER. Other issues regarding the RAB and adjustments to the asset base are addressed in Chapter 2.

Based on the requirements in the Rules and the RFM, EnergyAustralia's RAB for the beginning of the next regulatory control period is $8.22 billion[6]. This value represents the combined RAB value of our transmission and distribution networks.

In making a building block determination, the AER is required to determine an appropriate method for indexation of the RAB. That method must be a method that is likely to result in the best estimate of inflation[7].

3 Transitional Rule 6.12.1(2)
4 Transitional Rule 6.12.3(d)
5 Transitional Rule 6.4.3(a)
6 Nominal dollars
7 Transitional Rule 6.3.2(a)(2) and Schedule 6.2.3(c)(4)

1. Annual revenue requirement (continued)

EnergyAustralia proposes that the method to determine the best estimate of inflation is based on an average of the short and medium term inflation expectations published by the Reserve Bank of Australia (RBA), and other financial market institutions and professional forecasters. This approach is an extension of the method applied by the AER in the recent SP AusNet decision.

For the purposes of indexing the RAB for the 2009-14 regulatory period, EnergyAustralia's proposed methodology for determining the estimate for inflation is based on analysis and information provided by CEG in *"A Methodology for determining expected inflation"*[8] (Attachment 1.3).

Using this methodology, the inflation rate that EnergyAustralia has used as a basis for this Regulatory Proposal is 2.54 percent.

EnergyAustralia's RAB for the 2009-14 period is therefore based on:

- the opening asset base (using a roll forward of both the transmission and distribution RAB's in accordance with Schedule 6.2.1 of the Transitional Rules);
- the best estimate of inflation;
- annual forecast capital expenditure described in Chapters 3-6; and
- any other adjustments and calculations required in accordance with the Rules and demonstrated in the RFM produced by the AER.

EnergyAustralia's RAB during the regulatory control period is shown in Table 1.1[9].

Table 1.1: Regulatory asset base ($bn nominal)

	FY10	FY11	FY12	FY13	FY14
Opening RAB	8.22	9.80	11.43	13.36	15.25

In this proposal EnergyAustralia has consistently applied the proposed estimate of indexation to all relevant inflation and pricing escalations within the PTRM and RFM. Importantly, EnergyAustralia has applied the same method to all inflation dependent calculations associated with the control mechanism for Direct Control Services.

Further details of the establishment and roll forward of the RAB are found in Chapter 2.

1.4 Depreciation for the year

The building blocks include a revenue allowance for the return of capital (depreciation) over the regulatory control period. EnergyAustralia has used a straight line approach to depreciation over the regulatory control period, based on the opening RAB value and remaining asset lives. The remaining asset lives have been established by rolling forward the 2004 values, and adjusting for actual net capital expenditure and depreciation to 1 July 2009.

The calculation of the remaining asset lives at 1 July 2009 is demonstrated in the transmission and distribution roll forward models.

Details of the methodology used for calculating the depreciation schedules are found in Chapter 7.

The revenue allowance building block for depreciation, using the PTRM, is found in Table 1.2.

8 CEG A methodology for determining expected inflation – A report for NSW Electricity Network Service Providers

9 Source PTRM

Table 1.2: Depreciation building block calculation ($m nominal)

	FY10	FY11	FY12	FY13	FY14
Nominal Depreciation	285	353	418	493	535
Less inflation in RAB	209	249	290	339	387
Depreciation Building Block	77	104	128	153	148

1.5 Return on capital for the year

The building blocks include a revenue allowance for return on capital each year. Transitional Rule 6.5.2(b) stipulates that the rate of return must be based on the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider.

The AER will make a decision on the return on capital using the calculations and parameters codified in the Rules and the latest available information at the time of the determination. For the purposes of calculating the revenue requirement, EnergyAustralia has calculated the rate of return using the latest available information at the time of filing. On this basis, EnergyAustralia has estimated the return on capital to be 9.76 percent[10].

Further information regarding the assumptions and inputs to derive the rate of return is found in Chapter 8.

1.6 Operating expenditure

The building blocks include a revenue allowance for the annual operating expenditure which is required to achieve the operating expenditure objectives.

The forecast operating expenditure for each year of the regulatory control period, based on the rule requirements is set out in Table 1.3.

Table 1.3: Operating expenditure building block ($m nominal)

	FY10	FY11	FY12	FY13	FY14
Operating Expenditure	580	613	667	711	749

Details of how operating expenditure was forecast and used in the building blocks is found in Chapters 9 through 11.

1.7 Estimated cost of income tax for the year

The building blocks include a revenue allowance for the estimated cost of income tax for each year of the regulatory control period. The Rules require that this allowance be calculated on the taxable income that would be earned by a benchmark efficient entity as if such an entity, rather than the DNSP, operated the business.[11]

Details of the methodology and calculation of corporate income tax used in the building blocks is found in Chapter 12.

The building block for the estimated cost of income tax for each year, based on the Rule requirements, is set out in Table 1.4.

Table 1.4: Estimated corporate income tax building block ($m nominal)

	FY10	FY11	FY12	FY13	FY14
Estimated Income Tax	44	76	88	102	109

10 Rate of return is based on a nominal post-tax weighted average cost of capital calculated in accordance with the formula set out in Transitional Rule 6.5.2

11 Transitional Rule 6.5.3

1. Annual revenue requirement (continued)

1.8 Increments/decrements

The Transitional Rules[12] require a proposal to specify the treatment of increments and decrements on the annual revenue requirement.

During the 2009-14 period, it is likely that the only adjustments to the annual revenue requirement will relate to variations to the determination via the pass through mechanism. This mechanism is outlined in Transitional Rule 6.6.

Nevertheless, the Rules require these increments/ decrements to the annual revenue requirement and a suite of related adjustments to be included in the application of the control mechanism for Standard Control Services. This requirement is outlined in Chapter 13 and detailed in our Service Classification and Control Mechanism Proposal (Part II).

1.9 Conclusion

This chapter outlines the proposed annual revenue requirement of $10.01 billion which EnergyAustralia requires to provide the necessary Standard Control Services over the 2009-14 regulatory control period. This requirement has been properly calculated and forecast in accordance with the Rules.

12 Transitional Rules 6.4.3(a)(5), (6) & (8) and 6.4.3(b)(5), (6) & (8)

2. Regulatory asset base

The purpose of this chapter is to:

- establish the value of the RAB that is used by EnergyAustralia to provide Standard Control Services as at the beginning of the regulatory control period;
- demonstrate the calculation of the value of the RAB that will be used to provide Standard Control Services for each year of the regulatory control period; and
- demonstrate that these values have been calculated in accordance with the Rules and the AER's RFM.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(6))

The AER's determination is predicated on a number of decisions relevant to the regulatory asset base.

The first is a decision on the regulatory asset base as at the commencement of the regulatory control period in accordance with the AER's roll forward model, Clause 6.5.1 and Schedule 6.2.1[13].

Other decisions relate to other appropriate amounts, values or inputs relevant to the regulatory asset base including a decision on the calculations of the regulatory asset base for each regulatory year of the regulatory control period using the AER's roll forward model.

2.1 Summary

The nominal opening value of the regulatory asset base (RAB) for the 2009-14 regulatory control is $8.22 billion, based on:

- the values outlined in Schedule 6.2.1(c) which reflect the regulatory decisions in 2004;
- any adjustments to the values recognised in Schedule 6.2.1(c), para (2) and (3);
- actual capital expenditure incurred during the 2004-09 period consistent with Schedule 6.2.1(e)(1),(2) and (4);
- actual depreciation during the 2004-09 period consistent with Schedule 6.2.1(e)(5);
- disposals during the regulatory control period consistent with Schedule 6.2.1(e)(6);
- any adjustments for assets which previously provided Standard Control Services and which no longer provide these services (and vice versa);
- the actual inflation during the 2004-09 period, consistent with the indexation method used for establishing the control mechanism during the regulatory control period; and
- where actual inputs are not available estimates have been provided.

Details of the calculation, including the amounts, values and inputs used are provided in EnergyAustralia's completed RFM.

2.2 Opening values in the previous regulatory control period and necessary adjustments

Schedule 6.2.1(c) nominates two values that EnergyAustralia must take into account in establishing the opening asset base:

- $4,116 million (2004 dollars) which is intended to represent the opening value of the RAB for prescribed distribution services in the 2004-09 period; and
- $636 million which is intended to represent the opening value of the RAB for prescribed transmission service in the 2004-09 period.

13 Transitional Rule 6.12.1(6)

2. Regulatory asset base (continued)

2.2.1 Adjustment to reconcile network regulatory asset base values at a single point in time

In establishing the $4,116 million opening RAB for EnergyAustralia's distribution network, IPART took the most recent regulatory asset value for EnergyAustralia's entire network and netted out the regulatory values that had been set for the transmission asset base and for public lighting. The amount included in Schedule 6.2.1 therefore represents a net amount and includes an estimate of capital expenditure for 2003-04 as these costs were not known at the time of making the determination.

The amount ascribed to the transmission RAB was determined one year after the beginning of the regulatory control period (due to the delay in the release of the final determination for transmission).

The figure of $636 million nominated as the transmission RAB is therefore an actual value, and no forecast adjustment is required. However adjustments are needed to the RFM to reflect the timing differences in the determinations and the fact that the distribution RAB must be adjusted to reflect the difference between estimated and actual expenditure where the transmission RAB does not.

EnergyAustralia has used the RFM for the 2004-09 period, in respect of transmission network support assets to roll forward the asset base as if the AER were separately regulating EnergyAustralia's transmission system under the relevant provisions of Chapter 6A.

EnergyAustralia has prepared a document "EnergyAustralia's Opening Distribution RAB" (Attachment 2.1) that provides details on:

- the methodology employed by EnergyAustralia in establishing its opening RAB as at 1 July 2004; and
- the proposed approach for establishing the RAB value in 2009.

EnergyAustralia's approach is consistent with the approach that it applied at the last determination and is consistent with the Rule requirements.

2.2.2 Indexation of the regulatory asset base between regulatory control periods

The Rules prescribe the method for indexing the RAB to determine the opening RAB. Clause 6.5.1(e)(3) requires the asset based to be adjusted for:

"…actual inflation, consistent with the method used for the indexation of the control mechanism (or control mechanisms) for Standard Control Services during the immediately preceding regulatory control period."

This therefore requires a separate roll forward of the asset base for distribution and transmission using two different indexing methods.

Distribution: EnergyAustralia has rolled forward the distribution asset base between 2004-09 using actual CPI data for each financial year (ie July-June) based on the average of four quarters method for calculating the annual change in CPI (which was the method used by IPART when establishing the control mechanism in respect of the 2004-09 regulatory control period).

Transmission: EnergyAustralia has rolled forward the transmission asset base between 2004-09 using actual CPI data for each financial year (ie July-June) based on the year on year method for calculating the annual change in CPI (which was the method used by the ACCC when establishing the control mechanism in respect of the 2004-09 regulatory control period).

2.2.3 Estimated inflation assumptions for the last years of the current regulatory control period

At the time of submitting the Regulatory Proposal, actual CPI data was not available for either the 2007-08 financial year or the 2008-09 financial year. EnergyAustralia's RAB should therefore be adjusted for:

- actual annual CPI for the 2007-08 financial year when the information becomes available; and
- the best estimate CPI (using March 08-March 09 comparison) when making its final determination.

2.3 Rolling forward the regulatory asset base between years

EnergyAustralia's RAB is calculated for each year of the 2009-14 regulatory control period and is set out in Table 2.1.

Table 2.1: Regulatory asset base calculation ($bn nominal)

	FY10	FY11	FY12	FY13	FY14
Opening RAB	8.22	9.80	11.43	13.36	15.25

The increase in the RAB value up to 2014 gives an impression that EnergyAustralia proposes a large program of new works (ie capital broadening, not replacement). However a substantial part of the capital program is replacement which is in large part targeted at assets that are fully depreciated. Thus, the growth in the RAB value is simply a result of replacing fully depreciated assets with new undepreciated assets. In reality, around 10 percent of the asset base is being targeted through replacement programs during the 2009-14 regulatory period.
The calculation of the RAB for each year is based on:

- EnergyAustralia's RFM which has been completed in accordance with the Rules;
- the opening RAB for the 2009-14 period (explained above);
- forecast capital expenditure (explained in detail in Chapter 3);
- forecast depreciation (explained in detail in Chapter 7);
- forecast disposal values in accordance with Schedule 6.2.1(e)(6); and
- inflation determined in accordance with Schedule 6.2.3.

Details of all amounts, values and other inputs used by EnergyAustralia and an explanation of the calculation of the RAB for each year of the relevant regulatory control period are shown in the RFM.

2.4 Conclusion

Transitional Rules require the AER to make a decision on the RAB as at the commencement of the regulatory control period.

This chapter provides the AER with the opening value of EnergyAustralia's RAB ($8.22 billion) and outlines the process EnergyAustralia undertook to establish the value. The RAB has been calculated in accordance with Transitional Rule 6.5.1 and Schedule 6.2.

3. Capital expenditure overview and objectives

3.1 Summary

This chapter provides a summary of the capital forecast process which is discussed in further detail in the following three chapters.

This chapter provides an overview of the methodology EnergyAustralia uses to develop capital expenditure forecasts consistent with the Rules. This chapter also outlines how EnergyAustralia has considered the capital expenditure objectives in preparing its capital forecast.

Chapter 4 describes EnergyAustralia's obligations and explains how these obligations link to objectives and to investment drivers. The chapter also outlines how the impact of these drivers has been identified and forecast.

Chapter 5 describes the planning process used by EnergyAustralia to quantify the investment drivers in project and dollar terms.

In Chapter 6, EnergyAustralia identifies how it has considered the capital expenditure criteria and factors when establishing its capital expenditure forecasts.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.5.7)

A Building Block Proposal must include the total forecast capital expenditure which EnergyAustralia considers is required to achieve the capital expenditure objectives.

The capital expenditure objectives are:

(1) meet or manage the expected demand for Standard Control Services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of Standard Control Services;

(3) maintain the quality, reliability and security of supply of Standard Control Services; and

(4) maintain the reliability, safety and security of the distribution system through the supply of Standard Control Services.

The AER must accept EnergyAustralia's forecast of required capital expenditure if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects the *capital expenditure criteria*.

In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the *capital expenditure factors*.

EnergyAustralia's capital proposal has been prepared to address these requirements. This proposal specifically addresses how EnergyAustralia has developed a capital expenditure forecast which it considers is required to achieve the capital expenditure objectives, and, in doing so meet the capital expenditure criteria and factors.

A high level overview of EnergyAustralia's approach to capital expenditure forecasts is outlined in the next section.

3.2 EnergyAustralia's approach to developing its forecasts

This section provides a high level contextual overview of the next four chapters.

Our network – EnergyAustralia's network is divided into three distinct parts for planning purposes[14] – the transmission, subtransmission and distribution networks. These parts together form the network that delivers energy from TransGrid's BSPs to the customers throughout the area.

Transmission network – is the portion of the network that operates in support of TransGrid's 330kV system. These overhead and underground 132kV feeders connect EnergyAustralia's major substations to each other and to TransGrid's BSPs. These assets are a portion of the transmission assets that operate in parallel with and provide support to TransGrid's network.

Subtransmission network – comprises zone and subtransmission substations and the network which supplies these substations. It is made up of overhead and underground feeders that operate at 132kV, 66kV and 33kV. Some of these assets are considered to be transmission assets for the purposes of the AER's determination because they operate in parallel with and provide support to TransGrid's assets.

Distribution network – is made up of the distribution network (11kV) and the low voltage network (415V) which distributes energy from zone substations via distribution substations, kiosks, etc to customers.

All of these assets are considered to be distribution assets for AER regulatory purposes.

The part of the network being considered determines the method by which forecast needs have been identified. Investment forecasts for parts of the network that comprise a large number of small assets are developed on an asset population and risk basis. In parts of the network where there are a small number of very large assets, asset investment requirements are assessed for individual assets.

At the higher levels of the network, equipment is larger, more expensive and more strategic in terms of its role, and more significant in terms of the effect on customers if it fails in service.

EnergyAustralia has broken the transmission network into three areas – Inner Metropolitan, Central Coast and Lower Hunter. All drivers of investment at the transmission level of the network, such as capacity, condition and reliability, are considered together.

Similarly, EnergyAustralia has planned developments within the subtransmission network by breaking the network into 25 geographic areas. All drivers of investment within each area have been considered together and each subtransmission asset within the area has been assessed for its future capacity constraints, its condition, its contribution to network reliability performance and whether it is likely to be impacted by a new large customer connection.

EnergyAustralia has used a different approach to forecast capital investment requirements in the distribution network where assets are large in number, smaller in size, generally less expensive and less significant in terms of failure consequence.

EnergyAustralia has utilised forecasting models, statistical analysis and asset population risk assessment to develop capital investment requirements for the distribution network. Distribution investment planning is based on a single driver of investment. This is in contrast to planning the transmission/subtransmission network level which assesses multiple drivers to maximise synergies of individual strategic investments.

The objectives: EnergyAustralia has considered the capital expenditure objectives and has identified a set of investment criteria that when triggered ensure investments achieve the objectives.

Objective 1 – *to meet or manage expected demand for Standard Control Services* – is satisfied when EnergyAustralia is able to connect all new customers and other network users seeking access to the network and has sufficient network capacity to meet the demand of all existing customers connected to the network for Standard Control Services (i.e. access to capacity on the network so that energy can be distributed to their point of connection).

14 It should be noted that the use of the term transmission in this context does not match the term used in the Rules to distinguish EnergyAustralia's distribution and transmission network asset bases.

3. Capital expenditure overview and objectives (continued)

EnergyAustralia's investments that are triggered by new customer connections are therefore consistent with this objective. Furthermore, investments in new capacity or demand management initiatives are also consistent with this objective where failure to invest would result in EnergyAustralia not being able to satisfy this objective.

EnergyAustralia has investment criteria that when triggered result in investments that meet Objective 1.

The DRP licence conditions, for example, set mandatory planning criteria that distribution networks in NSW must use to provide Standard Control Services. The conditions set standards of security for various parts of the network. Where growth in demand for Standard Control Services is such that the planning criteria are no longer met, EnergyAustralia is in breach of its licence. Therefore, EnergyAustralia must invest in either additional network capacity or demand management where it can be foreseen that growth in demand will result in non-compliance. Investments made to ensure compliance with the design planning criteria are therefore required in order to meet Objective 1.

The DRP licence conditions also mandate reliability performance and effectively set the minimum reliability standards for Standard Control Services in NSW. Failure to deliver Standard Control Services in a manner that delivers this level of reliability will result in EnergyAustralia being in breach of its licence. Investments that are directed to ensure compliance with the standard are therefore required to achieve Objective 1.

In summary, the DRP licence conditions interpret how businesses in NSW should meet or manage demand for Standard Control Services and in doing so, set the investment criteria for businesses to use. When investments are triggered using this criteria, they achieve Objective 1.

Objective 2 – *to comply with regulatory obligations or requirements* – is also satisfied when DNSPs invest to meet mandatory planning requirements. However, regulatory obligations extend beyond the planning standards mentioned above, and include a wide variety of obligations including those related to worker and environmental safety.

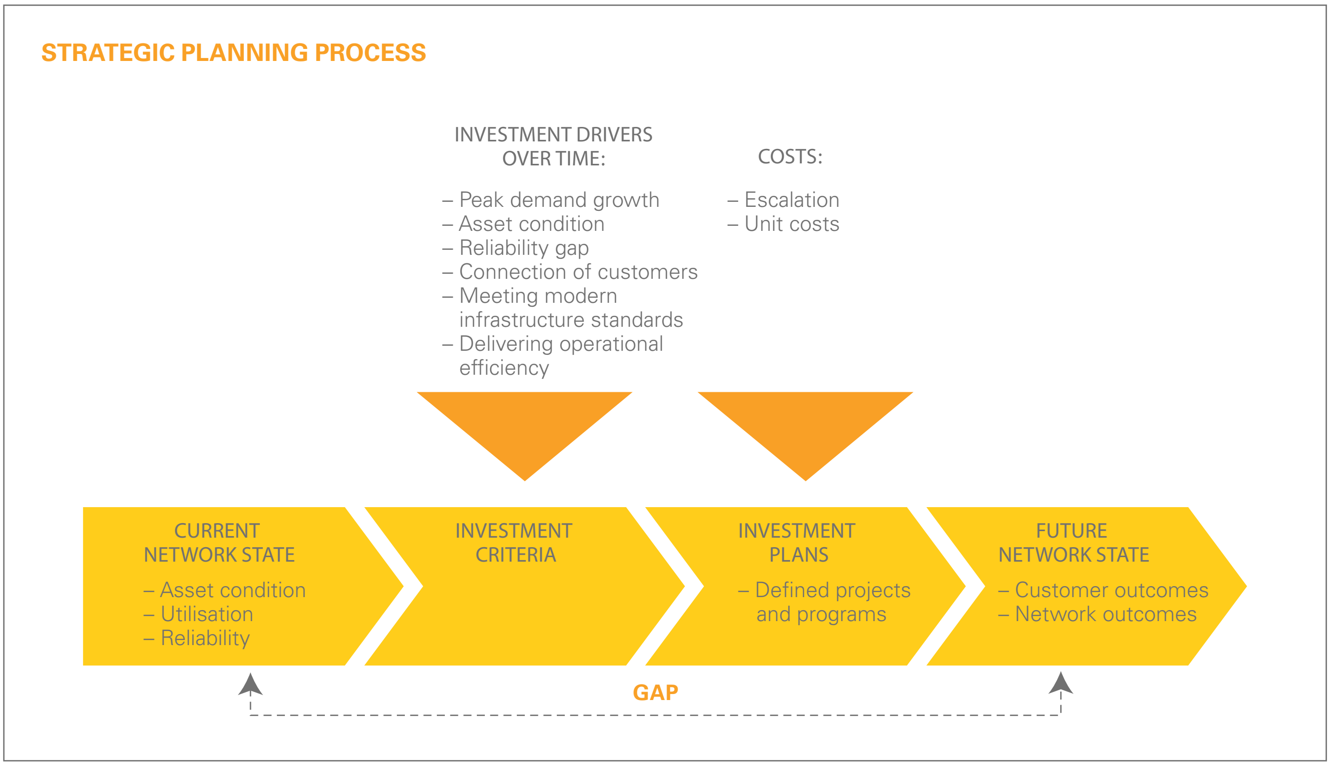
Objective 2 is satisfied when DNSPs invest to ensure that networks deliver services as required by the Rules, or when they invest to deliver outcomes that protect worker and environmental safety as required by the Protection of the Environment Operations Act and the Occupational Health and Safety Act and regulation. Investments that protect the safety of the public also satisfy this objective.

The investment criteria used to satisfy Objective 2 is set by identification of an obligation, and assessment of whether there is sufficient risk that the obligation will not be met without appropriate investment.

Objective 3 – *to maintain the quality, reliability and security of Standard Control Services* – is directed at ensuring that customers receive the appropriate levels of service. This is satisfied when DNSPs invest in network assets or network and business systems in order to maintain supply quality, network reliability and security of services. The investment trigger is based on analysis that shows service quality, network reliability or network security is substandard either now, or is likely to be substandard in the foreseeable future. Where investments address these issues, they achieve capital expenditure Objective 3.

The investment criteria are established using analysis that measures current levels of performance and predicts whether the level of performance should be maintained or improved. The DRP licence conditions set mandatory network performance. Investments are therefore triggered when performance information indicates that these standards will not be met.

Figure 3.1 Process for developing capital expenditure



3. Capital expenditure overview and objectives (continued)

Objective 4 – *maintain the reliability, safety and security of the distribution system* – is seemingly similar to Objective 3 but directed at ensuring that the network is operated, maintained and developed in such a manner as to ensure its sustainability. This is satisfied when DNSPs invest to deliver outcomes consistent with this objective. EnergyAustralia's investment criteria are designed to maintain reliability, safety and security of the electrical system and are grounded by a reliability centred asset management philosophy, using techniques such as Reliability Centred Maintenance (RCM) and Failure Modes Effects Criticality Analysis (FMECA).

EnergyAustralia is able to analyse the risk of asset failure, and assess the consequent risk to worker and public safety, and the impact on network reliability and security. The investment criteria are set by establishing a threshold for risk that EnergyAustralia will accept. Where asset condition or performance represents risk above this threshold, investments to address this risk are undertaken. Investments driven by risk assessment also extend beyond the network assets to systems that manage the network. Failure of key IT systems and databases, or lack of data security, has the potential to compromise EnergyAustralia's ability to identify risks correctly and therefore compromise EnergyAustralia's ability to invest appropriately to maintain the reliability, safety and security of the distribution system.

Our investment drivers: EnergyAustralia assesses network performance and support requirements against our obligations and the capital expenditure objectives. Our assessment incorporates changes in the circumstances of the network or changes to our obligations over the next regulatory control period and considers the impacts across the network, as well as impacts within specific geographic areas. This assessment focuses on changes which may impact network performance or support needs and require an investment response.

EnergyAustralia's assessment is based on forecasts which are developed to predict the change in circumstances over the next regulatory control period. This includes forecasts of demand growth, network reliability, and future asset condition which together predict overall future network performance.

Assessing current and future performance against known obligations and the "drivers of investment" identifies the gap which investment is required to ensure our customers receive the required service level during the regulatory control period. The drivers trigger the need for an investment response when the investment critieria are met. Investing at this point ensures EnergyAustralia is able to maintain compliance with its obligations and achieve the capital expenditure objectives.

For example, forecasts of demand growth identify gaps between current network capacity and the capacity required to meet EnergyAustralia's obligations to meet customer demand over the regulatory control period.

EnergyAustralia considers the impact of allowing these gaps to remain in addition to the risk of non-compliance with our obligations. Compliance with obligations and the extent to which compliance can be met in the absence of investment is a critical factor in determining whether the investment is incorporated into the proposal. EnergyAustralia has included all projects in its capital forecast that it requires to facilitate full compliance with existing obligations and achieving the capital expenditure objectives.

Capital Planning: EnergyAustralia uses a holistic planning approach when considering its obligations and drivers of investment. Where it is efficient to do so, EnergyAustralia's planners have tried to address multiple drivers with the same project.

For example, investments to address capacity shortfalls often influence a decision to replace an asset that displays poor reliability. Many investment options will typically have reliability benefits as well. In such circumstances, both the drivers and the benefits are considered together.

EnergyAustralia's Strategic Capital Development Planning process involves an iterative decision making process of assessing a number of variables:

- drivers;
- investment options;
- proposed solutions;
- project feasibility;
- project benefits; and
- risk.

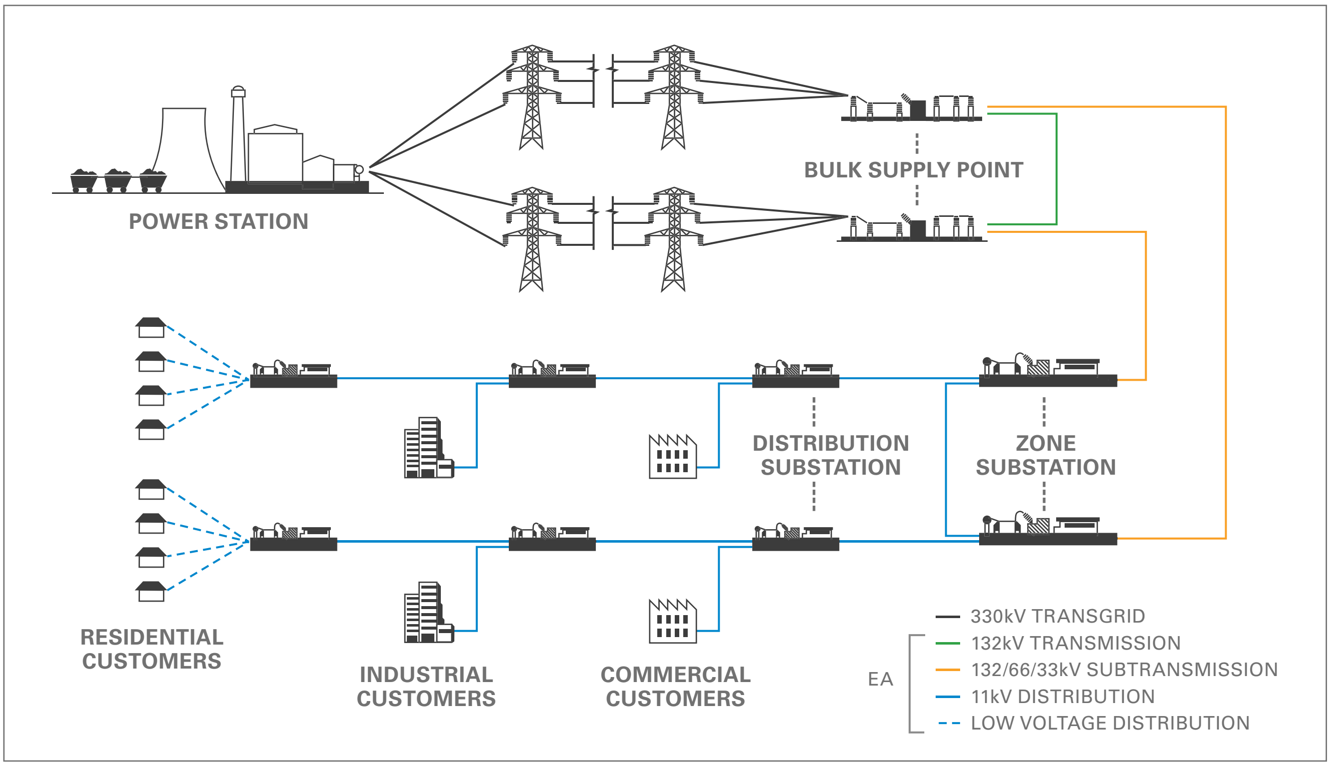
This assessment ultimately results in a suite of proposed investments which are presented in our series of investment plans.

The summation of the investment plans for the 2009-14 period forms EnergyAustralia's capital expenditure forecast.

As mentioned earlier, EnergyAustralia adopts different planning processes for different network types reflecting the number volume, strategic role, and value of the assets that fall under these network types.

- Planning for our **transmission** (132kV) and **subtransmission** (132kV, 66kV, 33kV) networks is typically conducted taking account of all drivers of investment simultaneously.
- Planning for our **distribution** (11kV) and **low voltage** (415V) networks is typically undertaken by considering one driver at a time, due to the large number of assets involved.

Figure 3.2: EnergyAustralia's network and its relationship to other parts of the supply chain



3. Capital expenditure overview and objectives (continued)

EnergyAustralia has also applied a strategic approach to consideration of **non-network capital investment** drivers. The process relies on assessment of future needs based on a comparison of current business capability and future requirements. A long term view has been taken for these investments and the resulting capital investment proposals are captured in a series of business focussed (as opposed to network focussed) investment strategies.

EnergyAustralia's approach to capital planning is discussed in detail in Chapter 5.

Consideration of capital expenditure criteria and factors: The approach outlined above represents a prudent and efficient approach to capital planning and results in an investment program that is driven by our obligations and our circumstances.

The costs in the investment plans represent efficient costs that would be required by any prudent DNSP operating in similar circumstances with a similar Rule compliance objective. We demonstrate how our capital forecast reasonably reflects the capital expenditure criteria and factors in Chapter 6.

3.3 Summary of capital expenditure proposed

EnergyAustralia forecasts that a total of $8.66 billion[15] of capital investment is required during the 2009-14 regulatory control period to achieve the capital expenditure objectives under the Rules. The forecast annual expenditure for each year of the regulatory control period is shown in Figure 3.3 and Table 3.1.

The annual capital expenditure throughout the period represents a substantial increase from current levels. The robust planning process EnergyAustralia has undertaken provides convincing evidence that investment at this increased level is required to sustain the network and our business for the next decade and beyond.

3.4 Highlights of the capital program

EnergyAustralia's capital expenditure forecast for the 2009-14 regulatory control period is summarised below.

EnergyAustralia's forecast capital expenditure:

- has been based on the allocation methodology provided in EnergyAustralia's cost allocation method to ensure costs are properly allocated to Standard Control Services; and
- in respect of complying with the AER's RIN, includes information required by the AER and is incorporated as part of this proposal.

15 Source: PTRM – FY09 Real Dollars

Figure 3.3: Forecast capital expenditure for 2009-14 (FY09 $bn real)

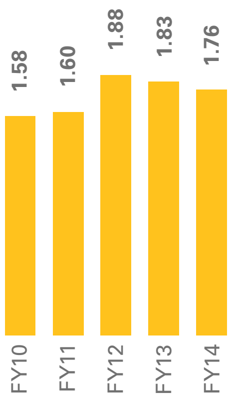


Table 3.1: EnergyAustralia's capital expenditure by network type and year (FY09 $m real)

	System Assets						Total
	Transmission	Sub transmission	11kV Distribution	Low Voltage	Other	Non System Assets	
Transmission Area Plans	368	76					443
Subtransmission Area Plans	725	2,279	502				3,506
Replacement Plan	13	474	793	514	34		1,828
11kV Network Development Model			698				698
Reliability Investment Plan			63	16			79
Low Voltage Capacity Plan				295			295
Duty of Care Plan	71	131	83				285
Customer Connections Plan		18	335	151			504
System and Business Support Plans					400	620	1,020
Total	**1,177**	**2,978**	**2,474**	**977**	**434**	**620**	**8,659**

	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Transmission Area Plans	131	62	120	60	71	443
Subtransmission Area Plans	600	681	778	779	669	3,506
Replacement Plan	253	322	366	414	473	1,828
11kV Network Development Model	59	110	167	172	190	698
Reliability Investment Plan	28	22	12	8	8	79
Low Voltage Capacity Plan	52	54	62	63	63	295
Duty of Care Plan	59	52	56	60	59	285
Customer Connections Plan	90	101	102	104	107	504
System and Business Support Plan	312	200	214	170	125	1,020
Total	**1,584**	**1,603**	**1,878**	**1,830**	**1,763**	**8,659**

3. Capital expenditure overview and objectives (continued)

The capital program represents the largest investment program to be undertaken by EnergyAustralia. It is the result of a detailed planning review that has taken place over two years and is an accurate reflection of the needs of the network in 2008-09 dollars.

The main features of the program are summarised here:

- **N-2 in the CBD:** By 2014, Sydney's CBD will have an electrical supply system with a level of quality and reliability comparable to any other in the world. This standard of service has been mandated through the DRP licence conditions for NSW DNSPs and represents a significant improvement in supply security.
- **Strategic replacement of critical assets:** EnergyAustralia's replacement program represents a healthy start to the replacement of key subtransmission assets such as 33kV gas and 132kV oil-filled cables and 11kV switchgear. These assets play a critical role in the distribution network and their strategic renewal is critical to maintaining supply reliability in future years. The program included in the 2009-14 period is just the start of a renewal phase that is forecast to take 15-20 years, by which time a new generation of assets will be installed to supply EnergyAustralia's area of operation for the next 50 years.
- **New (330/132kV) BSP:** EnergyAustralia's investment program includes connection to a new BSP which will be built by TransGrid in Sydney's west, as well as preparations for a BSP that will be required in Sydney's east in the 2014-19 period. Large scale injection facilities such as these are expected every seven years on average and are the reality of a growing economy.
- **New 11kV capacity:** The program incorporates substantial investment in 11kV network capacity to achieve compliance with utilisation levels set by the DRP licence conditions. This program will deliver significant improvements in 11kV network security and will dramatically improve customer reliability, particularly in terms of outage duration.
- **Reliability focus:** The program focuses on reliability at all levels of the network. For the first time, EnergyAustralia has been able to predict reliability improvements with accuracy as a result of sophisticated reliability modelling at the subtransmission level and within the 11kV network. The level of investment proposed throughout the network will deliver significant performance benefits. The corollary is that these benefits will not be delivered without the proposed program of investments.
- **Customer outcomes:** Customers will see improved average reliability of supply as a result of the capital program. The capital program delivers improved performance standards as required by the DRP licence conditions, through to June 2011, and will be maintained thereafter. Customers will also see improvements in local "black spots" in the network where smaller groups of customers are experiencing reliability problems that are not revealed by the average performance measures. This black spot program specifically improves network performance where individual customers are receiving poor reliability of supply performance.

The capital program proposed will enable EnergyAustralia to meet its network obligations and will deliver benefits to customers through improved reliability, provision of sufficient capacity to meet peak demand and lower risk of asset failure.

3.5 Conclusion

This chapter has provided an overview of the methodology EnergyAustralia uses to develop capital expenditure forecasts for its network, to achieve the objectives set out in the Rules. Also explained is how, in doing so, EnergyAustralia meets the capital expenditure criteria and factors.

A summary of EnergyAustralia's proposed capital expenditure program for the 2009-14 period is provided. This is the largest capital expenditure program on which EnergyAustralia has ever proposed to embark. An overview of the main elements of the program reveals three overarching themes to the proposed development: meeting obligations or requirements; the replacement of underperforming assets; and meeting the growth in customer demand.

4. EnergyAustralia's investment drivers

The purpose of this chapter is to outline how EnergyAustralia identifies drivers of investment required to meet capital expenditure objectives over the regulatory control period. It also explains the link between these investment drivers and EnergyAustralia's obligations.

The drivers of investment (collectively known as network performance drivers) are listed below:

- Peak demand growth – is the highest level of network capacity at a single point in time required by the sum of all customers' demand for network capacity. The growth in peak demand can trigger investment in additional capacity to provide Standard Control Services.
- Asset condition – is an engineering assessment of an asset's physical and functional characteristics to determine its suitability for continued service. Past reliability, likelihood of asset failure, and consequence of failure are all considered as part of this assessment. Investments are triggered when the asset condition is such that our ability to maintain the reliability, safety and security of the distribution/transmission system is compromised or begins to impair our ability to supply Standard Control Services of sufficient quality, reliability and security.
- Reliability gap – is the gap between existing network performance and the performance required by the DRP licence conditions. The gap narrows after investments have been made to cater for peak demand growth and asset condition. However, where a reliability gap remains, investment is triggered to address reliability issues and thereby ensure the service levels in the mandatory licence conditions (defined by SAIDI and SAIFI) are met.

The other drivers of network investment are:

- connection of customers and other network users – is the investment required by the connection of new customers and other network users to the network and includes investment made by EnergyAustralia to the shared network to facilitate these connections;
- meeting modern infrastructure standards – drives investment where installed equipment no longer meets modern infrastructure standards. Non-compliance occurs when assets remain in service for a long period of time, and despite being designed to meet the standards in place at the time they were constructed, standards have since changed and investment is required to ensure assets comply with modern standards; and
- delivering operational efficiency – drive investments that facilitate the operation of the network business and enable the continued delivery of our services.

4.1 Understanding our obligations

EnergyAustralia's investment program is linked to a variety of obligations that drive the way in which EnergyAustralia builds, operates and maintains its network and operates its business. In some cases, these obligations help define the practical application of the capital expenditure objectives to the network.

Our obligations therefore include those which fall within the definition of "*regulatory obligations or requirements*" as well as other business and governance requirements including those which apply because EnergyAustralia is a State Owned Corporation and carries on a business in NSW.

A full description of EnergyAustralia's legislative and regulatory obligations or requirements is detailed in Attachment 4.1. This explains EnergyAustralia's legislative obligations in four different categories:

- obligations which are industry specific;
- those that are of general application but have industry specific impacts;
- governance and financial obligations which are specific to NSW State Owned Corporations; and
- obligations which are of general application and apply to EnergyAustralia in the same way as any other business.

The obligations which are particularly relevant to the capital expenditure forecasts are summarised below.

The *Electricity Supply Act 1995 (NSW)* together with the *National Electricity Law (NEL)* and Rules are the principal sources of industry specific legislative/statutory obligations that lead to the identification of drivers of EnergyAustralia's capital expenditure.

There are also a number of general environmental, safety and security obligations that have specific impacts upon providers of electricity network services which significantly influence the identification of drivers for capital expenditure outcomes.

4. EnergyAustralia's investment drivers (continued)

For the purposes of this analysis, obligations associated with running the electrical network can be reduced to five key categories which broadly align with our investment drivers. These are:

1. **Obligation to connect all network users and meet customer demand for services**. This is considered as part of the demand capacity balance and customer connections drivers.
2. **Network planning operation and management**: Specifically the obligation to plan and develop networks in accordance with the National Electricity Rules (NER) and to maintain and implement a Network Management Plan (Attachment 4.2) and Bushfire Risk Management Plan (Attachment 4.3) required under the Electricity Supply Act. This is incorporated in our consideration of asset condition and network performance (Section 4.2).
3. **Network design, reliability, performance and service standards obligations**: Principally derived from the NSW DNSP licence conditions in particular and the Design, Reliability and Performance licence conditions[16] (DRP licence conditions) and Chapter 5 of the National Electricity Rules. These obligations are considered as part of the network performance, and network reliability drivers in particular.
4. **Network safety, security and management:** These obligations relate to the safety of workers, the environment and community more generally and are considered in the driver of meeting modern infrastructure standards.
5. **Obligations associated with running the business:** These obligations relate to body corporate governance and support, risk management regulation and compliance obligations which any business in EnergyAustralia's circumstance would be required to comply with.

Obligation to connect all network users

Under Section 15 of the *Electricity Supply Act, 1995 (NSW)* EnergyAustralia is obliged to provide customer connection services on request to any person who owns or occupies premises within EnergyAustralia's distribution district. These services are provided under either EnergyAustralia's Standard Form Customer Connection Contract (which in turn must comply with a range of requirements set by the *Electricity Supply (General) Regulation 2001)* or a negotiated customer connection contract (if agreed with the customer).

In the NEM, Chapter 5 of the NER places obligations on EnergyAustralia regarding managing enquiries and providing information to registered or intending participants about connections. It details how to make a connection enquiry, the information to be provided, notice and response to the connection enquiry, the application process, preparation of the offer to connect and finalisation of connection agreements. It also sets out the access arrangements for distribution and transmission networks.

Once connected, customers must be provided with services in accordance with (as appropriate):

- EnergyAustralia's Standard Form Customer Connection Contract, or the Chapter 5 Connection Agreement;
- the customer service standards in the DRP licence conditions; and
- the standards for network and system operation set out or established in accordance with the schedules to Chapter 5 of the NER.

In addition EnergyAustralia will be appointed as the Responsible Person for metering under Chapter 7 of the NER for customers with Type 5, 6 or 7 metering and any other customers for which a specific request has been received from the relevant retailer.

Metering services must be provided in accordance with the requirements of Chapter 7, the National Metrology Procedure and the requirements of the NSW specific Market Operation Rule (No 3 – New South Wales Rules for Electricity Metering).

Network planning, operation and management

These obligations are imposed by the *Electricity Supply Act*, specifically the *Electricity Supply (Safety and Network Management) Regulation 2002*, and NSW licence conditions as well as NER (principally Chapters 4 and 5).

Under the *Electricity Supply (Safety and Network Management) Regulation 2002*, EnergyAustralia must have in place and implement the following plans:

- Network Management Plan; and
- a Bush Fire Risk Management Plan.

16 Attachment 4.4: NSW DNSP Design Reliability and Performance Conditions (DRP licence conditions)

The purpose of our Network Management Plan is to ensure that the distribution (and transmission) system provides an adequate, reliable and safe supply of electricity of appropriate quality. A Network Management Plan must include a commitment by the network operator to ensure the safe operation of its distribution (and transmission) system and to give safety the highest priority over all other aspects of network management.

The Network Management Plan documents in one place all of the processes and strategies applied by the DNSP in the design, construction, operation and maintenance of the network. In particular the Plan documents asset management strategies and network safety management strategies including those applied to hazardous events and emergencies. The Plan also describes the codes, standards and guidelines which apply to the DNSP and the extent to which they are applied and implemented.

The Bushfire Risk Management Plan focuses specifically on planning and strategies to manage the risks associated with the operation of electricity lines near vegetation and bushfire risks.

EnergyAustralia must comply with a Network Management Plan and Bushfire Risk Management Plan lodged with the NSW Director General of Water and Energy.

EnergyAustralia's DNSP licence conditions impose obligations to investigate alternatives to network augmentation before augmenting its network.[17] The Demand Management Code published by the NSW Department of Water and Energy operates as a guide to complying with these obligations. This obligation is the foundation for EnergyAustralia's approach to Demand Management.

Chapter 4 of the NER is principally concerned with the power system security obligations of the National Electricity Market Management Company (NEMMCO). However a number of obligations are imposed upon EnergyAustralia due to the operation of its network in the interconnected national grid. In Chapter 4 these obligations relate to ensuring that controls, monitoring and secure communication systems are in place to enable load shedding and restoration following a prolonged major supply shortage or extreme power system disruption. In addition both DNSPs and TNSPs must plan or operate their transmission system or distribution system in accordance with NEMMCO's power system stability guidelines.

Both DNSPs and TNSPs must also comply with the requirements of Rule 5.6 regarding the planning and development of networks. These obligations include joint planning, application of the regulatory test and, if necessary, responding to direction notices given by the Australian Energy Market Commission (AEMC) under the last resort planning power.

In addition, Chapter 5 imposes obligations in relation to the management, maintenance and operation of its part of the national grid in a satisfactory operating state, within acceptable fault levels and to minimise interruptions to agreed capability at connection points by using good electricity industry practice.

Under Chapter 5 of the Rules, EnergyAustralia must also maintain and operate all equipment that is part of its facilities in accordance with: relevant laws; the requirements of the NER; and good electricity industry practice and applicable Australian Standards[18].

As a network service provider EnergyAustralia must also apply the planning, design and operating criteria described in Schedule 5.1 and comply with the power system performance and quality of supply standards described in that schedule. These include the system standards set out in Schedule 5.1a.

Network design, reliability, performance and service standards

Obligations in relation to the Network Design Reliability, Performance and Service are now imposed principally by the DRP licence conditions and the NER.

Design, reliability and performance licence conditions

These conditions, imposed by the NSW Minister of Energy in 2005 and updated in December 2007 are significant in contributing to the three drivers of network performance. These set requirements for EnergyAustralia's installed network capacity and targets for network performance.

The DRP licence conditions are summarised in Table 4.1 and are attached in full at Attachment 4.4. An explanation of the licence conditions and EnergyAustralia's approach to planning to meet these and other requirements is set out in EnergyAustralia's Design Planning and Area Planning assumptions at Attachment 4.5 (Planning Criteria).

17 Ministerially imposed licence condition 1.1, 1.2 and 1.3

18 National Electricity Rules – Management & Maintenance of Network – All customers cl 5.2.1 & 5.2.3 b & e1

4. EnergyAustralia's investment drivers (continued)

Table 4.1: DRP licence conditions summary

Schedule	Name	Summary
Schedule 1	Design Planning Criteria	Establishes minimum network back up capacity and limits for load at risk that planners must meet when planning augmentations of the network.
Schedule 2	Reliability Standards	Mandates minimum performance levels for average performance in each feeder category.
Schedule 3	Individual Feeder Standards	Mandates minimum performance levels for individual feeder reliability for each category of feeder.
Schedule 4	Excluded Interruptions	Outlines interruptions that are allowed to be excluded from statistics reported against Schedules 2 and 3.
Schedule 5	Customer Service Standard	Defines standards for maximum interruption durations and frequencies for individual customers. Customers who experience performance beyond these standards are eligible for financial compensation.
Schedule 6	Major Event Day	Describes the methodology for calculation of Major Event Days which are one of the exclusions allowed under Schedule 4.
Schedule 7	List of Metropolitan Areas	A list of all those suburbs considered to be metropolitan areas for the purposes of the Schedule 5 customer standards.

Obligations to run the business

The obligations discussed above in relation to running the network have significant implications for the way in which EnergyAustralia runs its business, specifically the provision of modern and often very sophisticated systems, equipment, facilities and IT infrastructure. In relation to business systems and IT infrastructure, EnergyAustralia's participation in the National Electricity Market requires the development of a range of systems to support such matters as Responsible Person obligations, customer transfer within NEMMCO's Market Settlement and Transfer Solution (MSATS) Procedures, National Metering Identifier (NMI) systems, billing obligations to customers and retailers and compliance with NSW Market Operations Rules and various B2B procedures within the NEM.

In addition, EnergyAustralia is a Statutory State Owned Corporation (SOC) under the State Owned Corporations Act 1989 (NSW) and an Energy Services Corporation under the Energy Services Corporations Act 1995. The governance and financial accountability arrangements which apply to EnergyAustralia broadly mirror those which apply to corporations. However, there are some differences to reflect accountabilities considered appropriate for a publicly owned corporation. Specifically, the Energy Services Corporations Act 1995 (NSW) sets objectives for transmission and distribution operators to be a successful business and operate at least as efficiently as any comparable business. EnergyAustralia must exhibit a sense of social responsibility by having regard to the community within which it operates and protect the environment and in doing so, maximise the net worth of the state's investment.

These obligations and all of the obligations discussed above drive the standards which EnergyAustralia must apply to the way in which it conducts its business and makes decisions regarding matters such as information technology systems, fleet management, and professional work places.

4.2 EnergyAustralia's investment drivers – network performance

This section identifies EnergyAustralia's investment drivers. It also identifies:

- the principal obligation to which the driver relates; and
- the methodology used to forecast the system need for each driver.

Drivers of investment are factors that change the circumstances of the network or the environment faced by the network, that contribute to increased operational risk or a risk of non-compliance with obligations. Drivers put pressure on the existing network and when certain criteria are met, trigger investment.

Network performance: is the name used by EnergyAustralia to define the overall outcomes seen by customers. It relates to the performance of the distribution (and transmission) network as a whole. EnergyAustralia's capability to provide Standard Control Services in a manner consistent with our obligations will be compromised unless the three drivers that contribute to network performance are appropriately managed. These are:

(a) Peak demand growth;

(b) Asset condition; and

(c) Network reliability.

Peak demand growth: EnergyAustralia is obliged to meet or manage demand growth. If this does not occur, network performance can be compromised where there is an imbalance of demand and capacity.

Demand growth occurs incrementally over time as a result of customers using more energy and demanding more capacity on the network.

Insufficient network capacity at peak times may result in load being disconnected to protect equipment and network stability.

Provision of sufficient network capacity at peak times combined with management of demand where appropriate can mitigate the risk of outages and ensure good network performance and good reliability outcomes for customers.

Asset condition: Network performance is influenced by the condition of individual assets. Assets that are in poor condition cannot be relied upon to continue to function in a manner consistent with their intended design. Assets that fail in service contribute significantly to poor network performance outcomes for customers and may put staff and the public at risk of injury. EnergyAustralia uses a sophisticated condition based maintenance regime to monitor asset condition and thereby enable investment managers to balance risks and costs of ongoing service of these assets. Where asset failure risks are high and reliability or safety issues are present or likely, assets are recommended for replacement.

Network reliability: Network performance is also affected by reliability of segments of the network. Network reliability, or lack of reliability, can be caused by network design, interference from wildlife and vegetation, and lack of in-built redundancy. These factors can drive an investment response where their impact on reliability is significant, or where performance of a part of the network is unacceptable due to network security risks or network reliability standards.

Network performance is measured in high level terms under the DRP licence conditions by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These are considered both at a feeder category level and for individual feeders. A lack of network capacity or the presence of poorly performing assets can negatively impact both SAIDI and SAIFI.

EnergyAustralia has specific standards it must meet for SAIDI and SAIFI performance at the feeder category level (Schedule 2) and the individual feeder level (Schedule 3).

EnergyAustralia's ability to meet these standards can be compromised by these three drivers – peak demand growth, asset condition and network reliability – if they are not managed through appropriate investment. Even where the performance gaps associated with these specific drivers are addressed, further analysis is required to identify any residual reliability gaps that limit EnergyAustralia from achieving its network performance obligations. This further step is the basis of our Reliability Investment Plan.

4. EnergyAustralia's investment drivers (continued)

4.2.1 Peak demand growth

EnergyAustralia is required to provide Standard Control Services to meet customer demand. This means EnergyAustralia must provide sufficient network capacity to supply all connected customers as well as provide sufficient capacity to satisfy committed demand from new customers.

Relationship between peak demand growth and energy growth

In recent history, the underlying rate of growth in peak demand has significantly exceeded the rate of growth in annual energy consumption, not only in the EnergyAustralia network region but also at the NSW state level and in other states.

EnergyAustralia forecasts growth in energy consumption to be 0.1 percent in the residential sector and 2.4 percent in the non-residential sector. The average energy growth across EnergyAustralia's network area is forecast to be 1.6 percent.

In contrast, the growth in peak demand is considerably higher with residential peak demand growth of 3.7 percent and non-residential peak demand growth of 2.2 percent. The average peak demand growth is 2.8 percent. This is represented in Figure 4.1.

The differential between the rate of growth in energy and the rate of growth in peak demand can be attributed to the recent increase in the penetration of air conditioning in residential premises. Air conditioners have a disproportionately higher impact on system peak demand compared with annual energy because they are used for reasonably short periods of time. Penetration of air conditioning is still relatively low in Sydney and it can be expected to rise over time and contribute disproportionately to the growth of summer peak demand in future. It should be noted that most of EnergyAustralia's growth related capital investment is forecast to occur in areas that are predominantly residential.

The disconnect between the growth rates of peak demand (a key driver of growth-related capital expenditure requirements) and average annual energy volume (which is a key driver of establishing X factors and prices) highlights how changes in customer behaviour can have disproportionate impacts on a network's cost drivers on the one hand, compared to the relatively small impact on revenue on the other hand.

EnergyAustralia's load forecasting methodology is designed to factor in these growth disconnects by:

- developing global (or network-wide forecasts) of peak demand and annual energy consumption, where the forecasts of both parameters share common assumptions as to future trends in the key drivers of consumption, in particular customer numbers and customer consumption patterns (see Attachment 13.2– Energy and Global Peak Demand Forecasts to 2014); and
- using the global peak demand forecasts as a logic check of the reasonableness of the peak demand growth forecasts implicit in the spatial forecasts. This comparison is conducted at a high level between regional global peak demand and aggregate spatial demand at 132kV connection points.

Accordingly, assumptions affecting either the energy consumption forecast or the peak demand forecasts are referenced to the other and thereby consistent across the different forecasting models. Acceptance of the assumptions underlying one methodology has implications for acceptance of the assumptions underlying the other.

As explained in EnergyAustralia's submission to IPART in 2004 our zone substations continue to move from winter peaking to summer peaking due to the end use of electricity, particularly air conditioning. Figure 4.2 illustrates the change in mix of winter and summer loading experienced at our zone substations. It shows that at the beginning of the current regulatory period 55 percent of our zone substations were summer peaking and by the end of the next control period approximately 78 percent will be summer peaking. This is important to understand as in summer our system has less capability to deliver energy at peak than in winter as equipment ratings are limited by their temperature. In summer the ambient temperate is higher and equipment ratings lower, as such it has less capability than in winter. This compounds the need to invest in capacity.

Relationship between peak demand growth and licence obligations

A key trigger of growth related investment is the DRP licence conditions which mandate minimum network security and limit load at risk (i.e. the level/time during which load can be above a zone substation's firm rating).

Figure 4.1: Average energy growth and average peak demand growth in EnergyAustralia's network area (2009-14)

Where growth in demand for Standard Control Services reaches the trigger point, EnergyAustralia is obliged to invest in either additional network capacity, transfer load to better utilise existing capacity, or invest in programs that manage demand in that location. Investment driven by the demand capacity balance is consistent with EnergyAustralia's objective to meet or manage the expected demand for Standard Control Services over the 2009-14 period.

The key input to assessing the level of investment required is a forecast of capacity constraints. This forecast is undertaken at both a global and a spatial level. The methodology for developing these forecasts is explained below.

Forecast of capacity constraint (spatial forecast)

EnergyAustralia's installed capacity is set by the equipment rating based on manufacturing standards, standard industry practice and EnergyAustralia's history and experience in rating equipment.

EnergyAustralia has forecast the demand for Standard Control Services using global and spatial forecasts. The spatial forecast is used to identify locations where expected growth in peak demand is likely to trigger a network investment within the 2009-14 period.

EnergyAustralia's spatial forecast is based on peak loads recorded at each zone and subtransmission substation. The spatial forecast comprises the expected peak capacity requirements at each location seven years (or 10 years for subtransmission substations) into the future. The forecast of expected peak demand is based on:

- historical trends of peak demand growth both at the location and across the network;
- committed increases in demand for capacity within the surrounding area (i.e. spot loads); and
- known load transfers from surrounding zones.

EnergyAustralia's spatial demand forecasting process is explained in detail in Attachment 4.6. EnergyAustralia's Spatial Forecast Process.

EnergyAustralia's spatial forecast is compared against EnergyAustralia's seasonal peak demand forecast by comparing the aggregated spatial forecast for substations connected to the 132kV system with regional seasonal peak demand.

Despite the fact that the forecasts are not equivalent – one forecasts the growth in peak demand growth at the local level, and the other forecasts the growth in peak demand across a region – the forecasts at a regional and total network level exhibit comparable growth rates. This comparison acts as a logic check between the two types of forecasts.

The zone and subtransmission substation (STS) spatial forecast informs EnergyAustralia's expectation of future network capacity constraints and represents the baseline forecast of the capacity likely to be required by customers' demand for Standard Control Services in the future.

EnergyAustralia's spatial forecast is published each year in the Annual Electricity System Development Review (AESDR) and is available on EnergyAustralia's website. The most recent AESDR is attached as Attachment 4.7.

By using the installed capacity of the network and the forecast of future demand, EnergyAustralia's planners are able to identify the zone and subtransmission substations, and feeders that are impacted by peak demand growth and therefore require an investment response.

This can be seen clearly in Table 4.2 which is an extract from the 2006-07 summer forecast and shows that firm capacity is forecast to be exceeded at Botany zone in 2007-08.

4. EnergyAustralia's investment drivers (continued)

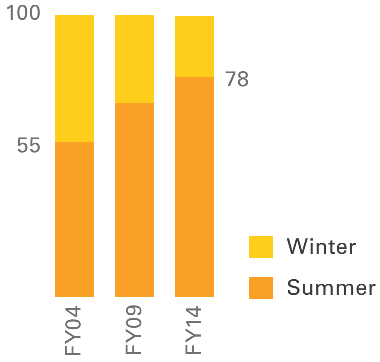
Table 4.2 Extract from spatial forecast

System Development Review based on Summer 2006/07 Forecast										
Zone Substation name:			Botany							
Locality:			Botany							
Interconnecting Zone Substations:			Mascot, Matraville, Maroubra							
Region:			Sydney City							
Power Factor at Time of Peak:				T2	T3	T4				
Year Power Factor Measured:			2006/07	0.83	0.86	0.85				
	Year	Limitation	Total Capacity MVA	Secure Capacity MVA	Peak Load MVA	Load/ Secure Capacity	Hours > Secure Capacity	Number of Transformers	115% x Load > Total Capacity	
Actual	99/00				33.7					
	00/01				35.0					
	01/02				34.2					
	02/03				35.6					
	03/04				35.1					
	04/05				37.7					
	05/06				39.8					
	06/07	N-1	44.3	36.9	37.7	102%	3.0	4		
Projected	07/08	N-1	44.3	36.9	42.1	114%	78.5	4		
	08/09	N-1	44.3	36.9	43.4	118%	140.0	4		
	09/10	N-1	44.3	36.9	44.7	121%	243.8	4		
	10/11	N-1	44.3	36.9	46.0	125%	372.0	4		
	11/12	N-1	44.3	36.9	47.4	129%	532.3	4		
	12/13	N-1	44.3	36.9	48.8	132%	705.3	4		
	13/14	N-1	44.3	36.9	50.3	136%	855.0	4		
Is there an investment trigger within 5 years?									YES	

Total capacity - is the maximum load able to be carried by the substation. Substations limited to N must ensure their total capacity exceeds the forecast load by 15 percent.

Secure capacity (or firm rating) - is the capacity of a substation with one major piece of apparatus out of service, this is often referred to as its N-1 rating.

Figure 4.2: Zone substations - summer verse winter peaking (percent)



Capacity constraints can also be triggered by insufficient feeder capacity. EnergyAustralia has developed a feeder forecast (as distinct from a zone substation forecast) which will form part of EnergyAustralia's AESDR in future years.

The spatial forecast and the resulting capacity constraints form critical inputs into the planning process for growth related projects.

To this extent, EnergyAustralia sought independent advice from CRA International on its forecasting process and its reasonableness. CRA concluded by saying *'that the modified spatial demand approach used in constructing the forecast for summer 2007 and beyond was a reasonable course of action'*. A full copy of their advice can be found in Attachment 4.6.

Spatial forecasts in the longer term

EnergyAustralia's spatial forecast is made for a period of seven years into the future for zone substations, and 10 years at the subtransmission substation level. While this represents a realistic expectation of demand in the 2009-14 period, it does not extend far enough into the future for long term strategic planning.

Strategic planning requires a longer term forecast than is provided by the spatial forecast. More than 10 years into the future there is insufficient knowledge of the factors which will influence demand at a micro level and differentiate the level of growth at individual substations within a region. Consequently EnergyAustralia has used the regional (econometric) growth forecast as the basis for its long term (10+ years) spatial forecast.

Forecast of capacity constraint (global forecast)

At the distribution and low voltage level, investment requirements are also driven by spatial demand growth and influenced by the behaviour of individual customers over time.

However the sheer magnitude and volume of assets and customers makes it impractical (and certainly inefficient) to predict with certainty, individual augmentation projects that will be required over more than the short term (1-2 years).

EnergyAustralia therefore assesses network capital requirements for the distribution and lower voltage part of the network based on the demand forecast at a whole of network level (or global level). This forecast is based on econometric information as well as appliance mix and customer type. The forecast indicates changes in peak demand over the whole network or on a regional basis[19].

The global peak demand forecast is used to indicate the expected change in peak demand on average across the network. It sets the growth rate used to forecast network wide growth driven investment programs such as capacity investment programs on the distribution network. EnergyAustralia has used the global peak demand forecast as a key input of growth to the 11kV *Distribution Mains Capital Requirements 2009-14* and the *Distribution Substation and Low Voltage Network Capacity Requirements 2009/10 to 2013/14*.

Circumstances

In 2005, 68 zone and subtransmission substations were loaded above their firm rating. This means that not all load would be able to be served at peak demand in the event of key equipment failure. Of these, 25 zones were loaded above the investment trigger point that applied in 2005.

EnergyAustralia's submission in 2004 predicted that 10 zone substations would be loaded above the investment trigger criteria at the end of the current period (2009). This was based on the most recent zone spatial forecast available at that time. However, the initial DRP licence conditions (introduced in 2005) required EnergyAustralia to ensure that there were no zones above the limit by 2009.

A subsequent review of the planning criteria of the DRP licence conditions in 2007 deferred the requirement for compliance to 2014.

19 EnergyAustralia uses five regions for the purposes of global forecasts. These regions reflect to the areas that are supplied by TransGrid's 330/132kV BSPs.

4. EnergyAustralia's investment drivers (continued)

Table 4.3 shows the number of zone and subtransmission substations that were over firm rating and/or loaded above the investment trigger in 2005 and are likely to be above criteria in 2010. About two thirds of the zones loaded above the licence criteria are located in the Hunter/Newcastle region. This reflects the high levels of growth seen in the Hunter region driven by greater penetration of air conditioning as well as the under investment in the Hunter network that occurred in the 1990s.

Table 4.3: Zone and STS loading

Zone & subtransmission substations	2005	2010
Over firm rating but within licence criteria	43	31
Over firm rating	25	6
Sum Total	68	37

In the distribution network, utilisation levels are currently very high on average across the network. Figure 4.3 shows that 184 feeders (11 percent) in the Sydney area are currently loaded above 80 percent utilisation.[20]

Figure 4.4 shows that, in the Hunter region, 110 distribution feeders have been identified as being over 80 percent utilisation. This is consistent with the results for zone substations and reflects the combined impact of higher growth rates and previous under investment.

The strategic planning process used by EnergyAustralia to develop its capital proposal utilises the spatial forecast for subtransmission network planning.

EnergyAustralia applies the global peak demand growth rates to capacity driven investment programs that are network wide.

The process used to develop the strategic investment plan for both the subtransmission and the distribution network is discussed in the next chapter.

4.2.2 Asset condition

Obligations

Poorly performing equipment and failure of equipment to operate in a safe manner is a key driver of poor network performance and often results in negative customer reliability outcomes. Public and workforce safety can be compromised where action is not taken to address the primary driver of poor asset condition. Poor asset performance compromises EnergyAustralia's ability to maintain the quality, reliability and security of services and the safe operation of its network, both of which are capital expenditure objectives under the Transitional Rules.

In general, asset condition deteriorates and failure rates increase as assets age. While asset age is not a driver of replacement per se, asset age, and particularly the age of a population of assets can indicate increased levels of risk of asset failure.

The identification and prioritisation of asset replacement requirements is therefore a risk assessment exercise. The prioritisation and systematic replacement of poorly performing assets is the mechanism through which EnergyAustralia maintains the quality, reliability and security of services to customers and to maintain the reliability, safety and security of its network. Furthermore, asset replacement enables EnergyAustralia to maintain its network in a safe manner consistent with its OH&S obligations. A failure to replace assets before they reach random failure mode can have severe safety and reliability consequences for the network as a whole, EnergyAustralia's staff and our customers.

Assessing the replacement need

EnergyAustralia's replacement requirement is grounded in condition assessments of network assets obtained through maintenance, on-going testing programs or specific asset investigations. All network assets have been analysed using a combined FMECA[21] and RCM[22] methodology to establish a robust maintenance program.

20 80 percent utilisation is a target in the Design Planning Criteria in Schedule 1 of the DRP licence conditions.

21 Failure Mode, Effect and Critically Analysis – is the tool used to examine how assets fail and what maintenance steps can be taken to avoid asset failure.

22 Reliability Centred Maintenance – is the philosophy behind the maintenance program. RCM directs maintenance to assets that have reached a certain age or time in service. RCM requires condition monitoring to ensure that maintenance is appropriately directed.

Figure 4.3: Distribution Feeder Utilisation[23] (Sydney excluding CBD)

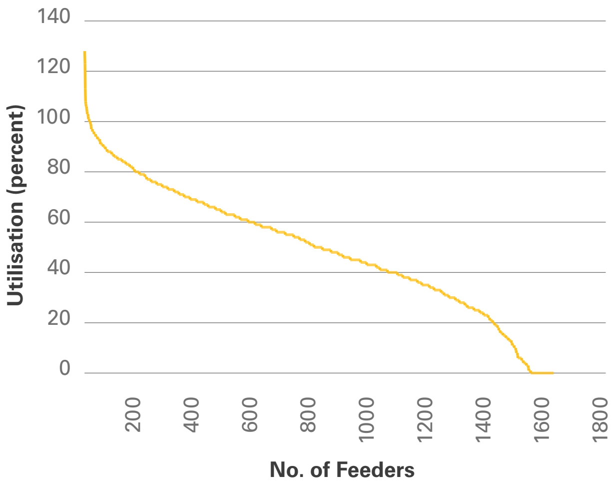
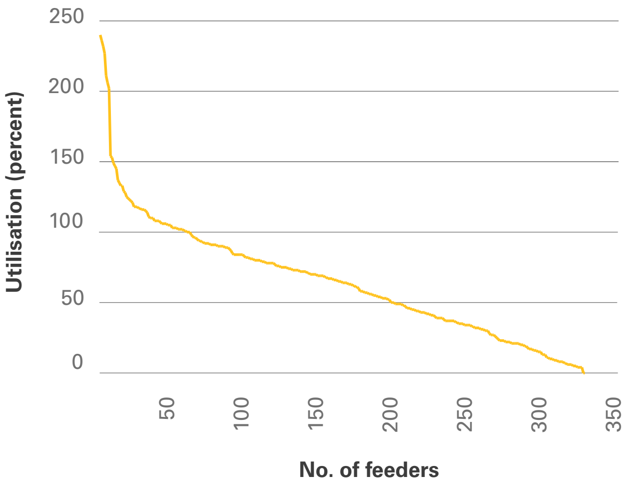


Figure 4.4: Distribution Feeder (Hunter) Utilisation[23]



This approach is an essential starting point for a condition-based replacement strategy such as that developed by EnergyAustralia and outlined in the Replacement Plan (Attachment 4.8). Further information on the FMECA and RCM methodologies can be found in Section 9.6: Maintenance costs.

The assessment of replacement requirements is a key input into the strategic planning process discussed in Chapter 5.

Asset replacement requirements are assessed by asset managers who review asset performance, asset failure data and condition information to identify emerging issues with assets or asset types. Where assets are not performing to the required levels, or a change in failure rates has been identified, maintenance strategies are reviewed to identify if this failure mode can be efficiently managed via maintenance. However, where a failure mode cannot be efficiently managed or mitigated through maintenance practices, an asset repair/replacement decision is required.

The decision to replace an asset is made for each individual asset at a subtransmission level. This is because the value of assets in the subtransmission network makes it cost effective to obtain condition data and undertake risk analysis for the individual piece of equipment. The prioritised replacement list for key assets is a critical input to the strategic network planning processes that are outlined in Chapter 5.

At a distribution level, decisions are based on assessment of types of assets or classes of assets based on aggregate information. Where there are large volumes of the same type of assets, asset managers also consider factors such as asset age profiles, the size of the population, accessibility of the assets, their criticality and the consequence of their failure. EnergyAustralia also considers the possibility and consequence of asset failure across an entire asset class which could include wide spread outages and subsequent price shocks for customers if entire classes of assets are replaced under emergency conditions.

Asset managers make decisions to replace or repair assets, or to let the assets run to failure based on a detailed risk assessment. EnergyAustralia uses a risk matrix based on AS/NZS 4360 Risk Management and AS/NZS 3931 Risk Analysis of Technological Systems - Application Guide to quantify failure frequency and consequence of asset failure[24].

Where appropriate, detailed investigations are commissioned to ensure that trends identified through data analysis are supported by system wide surveys of asset condition. Once this detailed condition assessment is completed, assets identified for replacement are prioritised based on the risk analysis.

Circumstances

EnergyAustralia has developed a robust methodology to determine asset replacement requirements because we have one of the oldest networks in Australia and because asset age and condition is the most significant driver of EnergyAustralia's capital proposal for the 2009-14 period.

EnergyAustralia's Sydney network is characterised by high population density and congestion which leads to the extensive use of underground assets. These assets are more expensive to install than overhead assets, and are generally very reliable. However, when they fail or deteriorate, they are very difficult to maintain and costly to repair.

EnergyAustralia has the largest amount of underground subtransmission feeders within its network of any DNSP or TNSP in Australia. EnergyAustralia's network is therefore unique amongst its Australian peers and faces unique challenges in terms of maintenance, construction and asset replacement.

EnergyAustralia has the oldest 11kV switchgear in Australia and a large proportion of subtransmission cables that are in service beyond their standard life.

23 Reflects normal state which is managed via abnormal switching to keep load within equipment rating.

24 Source EnergyAustralia's Maintenance Requirements Manual.

4. EnergyAustralia's investment drivers (continued)

Figure 4.5 shows the age profile of switchgear in service in Australia and New Zealand (according to a CIGRE[25] survey conducted in 2005). EnergyAustralia owns the oldest 1113 units of zone substation 11kV switchgear in service in Australia (those circled).

EnergyAustralia also has a further 1200 units that will reach their standard life within 10 years. The age and poor reliability of 11kV switchgear is critical to the reliable function and performance of EnergyAustralia's distribution network. Together with poor reliability of subtransmission cables, there is a significant risk to EnergyAustralia's reliability performance in the 2009-14 period.

Figure 4.6 shows EnergyAustralia's population of underground subtransmission feeders and the significant proportion of feeders above 50 years of age.

EnergyAustralia's distribution network is also aged and is displaying trends of increasing numbers of failures and poor reliability. Figure 4.7 shows the age profile for distribution substations in 2007[26].

As described earlier, EnergyAustralia does not make its replacement decisions on the basis of asset age. However, asset age, particularly the age of a large population of assets is a critical factor influencing long term replacement plans. In the case of distribution substations, it would be imprudent for EnergyAustralia to wait until 10 percent of its 29,000 distribution substations exhibit signs of impending failure. Asset populations of this size must be subject to strategic and continual renewal in advance of large portions of the population reaching the end of their design life. Otherwise the assets would enter a period of unreliability where failures cannot be predicted or managed appropriately. The fact that EnergyAustralia has managed its network to reach the current age profiles is a result of asset condition monitoring and maintenance.

It should be noted that if EnergyAustralia did directly apply age as a replacement criteria, the replacement program forecast would be significantly greater than is proposed for the 2009-14 period.

The strategic planning process outlined in Chapter 5 describes how the prioritisation of replacement requirements is incorporated into network investment plans which form the basis of our capital proposal.

4.2.3 Reliability gap

There is a gap between EnergyAustralia's average past performance and the required level of targeted performance as set by the DRP licence conditions. This gap must be bridged in order to maintain an acceptably low risk of non-compliance in any one year with the reliability standards in Schedule 2 of the DRP licence conditions.

This gap cannot be met purely by traditional asset management practices which address growth and replacement requirements.

Obligations

The DRP licence conditions require EnergyAustralia to meet a set of average feeder category performance standards as well as individual feeder performance standards (outlined in Schedules 2 and 3 of the licence conditions).

In NSW, the DRP licence conditions provide guidance to NSW distribution businesses about how the reliability capital expenditure objectives[27] should be applied in practice.

25 CIGRE is the international council on large electricity systems.

26 Distribution substations are used as a surrogate for the distribution network as feeders would have been constructed at the same time as the substations.

27 Reliability capex objectives are Objectives 3 and 4.

Figure 4.5: Australian and New Zealand zone substation 11kV switchgear age profile[28]

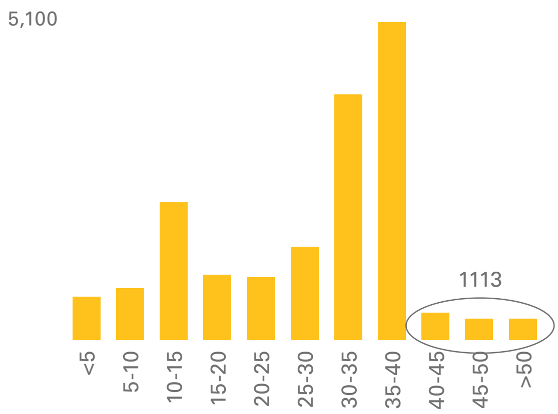


Figure 4.6: EnergyAustralia's subtransmission underground feeder age profile (2007)

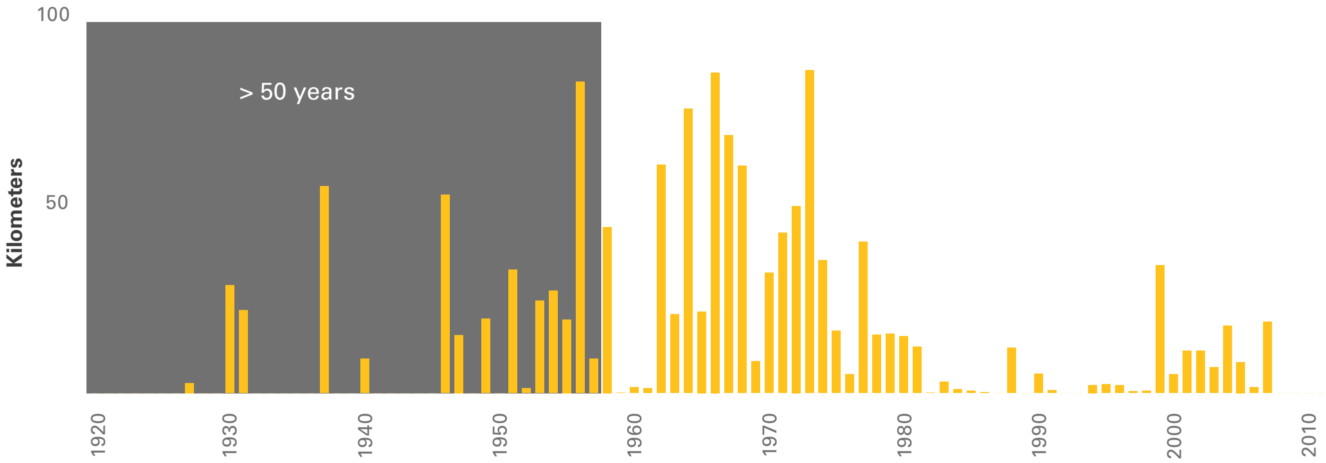
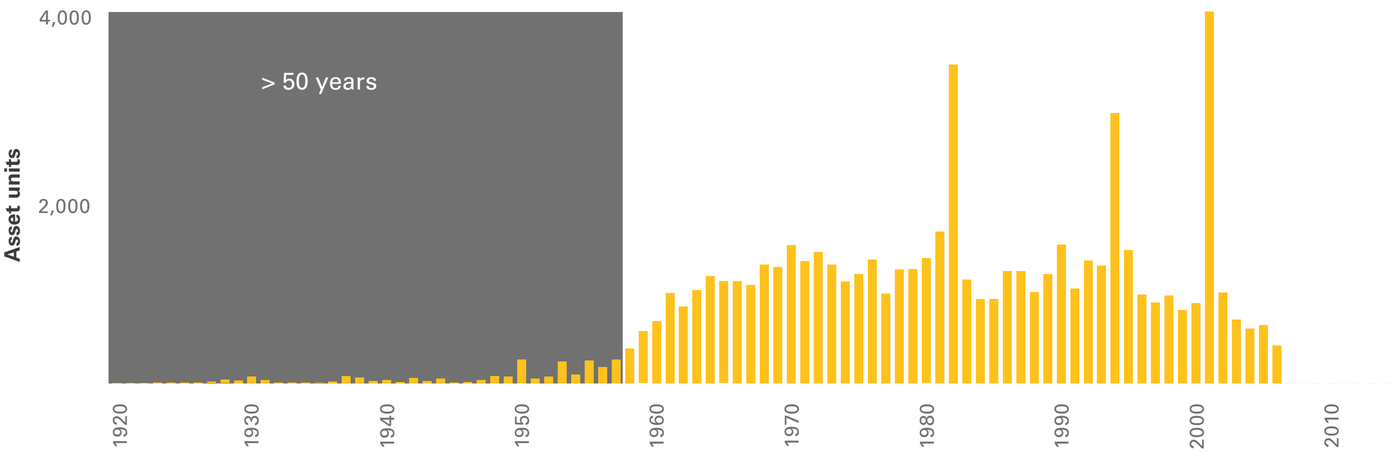


Figure 4.7: EnergyAustralia's distribution substations age profile (2007)



28 Data comes from a CIGRE survey of the age of switchgear still in service in Australian and New Zealand Distribution businesses.

4. EnergyAustralia's investment drivers (continued)

Historically, EnergyAustralia has managed reliability performance primarily through compliance with planning standards, asset management with a focus on reducing asset failures, and limited projects focussed on under performing feeders.

The DRP licence conditions, particularly the Schedule 2 – SAIDI and SAIFI Reliability Standards – introduces a mandated reliability performance standard which must be met.

This driver therefore focuses on the residual investment necessary to address the reliability "gap" that remains after investments driven by replacement and growth have taken place.

Investments required to comply with the licence conditions is consistent with three of the four capital expenditure objectives outlined in the Rules.

Determining reliability requirements

Annual reliability results are expected to have stochastic variation due to variable annual influences such as weather patterns and storms.

The Schedule 2 reliability standards represent the lower bound of a performance limit, not a target, and therefore oblige EnergyAustralia to aim for a level of targeted performance better than the Schedule 2 reliability standards in order to maintain an acceptable risk of non-compliance.

There is a gap between EnergyAustralia's average past performance and level of targeted performance. This gap must be bridged in order to maintain an acceptably low risk of non-compliance with the Schedule 2 reliability standards.

EnergyAustralia has calculated the positive impact that the proposed capital investment program is likely to have on network reliability. The proposed capital program contributes a reliability benefit that in most cases addresses a significant portion of the reliability gaps identified.

However, where gaps remain after consideration of proposed investments, EnergyAustralia has developed a capital investment program that targets reliability improvements aimed at meeting more onerous Schedule 2 requirements.

Circumstances

EnergyAustralia has conducted analysis to determine whether current network performance is sufficient to meet reliability targets in the future. The DRP licence conditions require an improvement in reliability from current levels.

Figure 4.8 shows the percentage improvement built in to the reliability standards (Schedule 2). For example, the urban SAIFI target improves by eight percent in 2010-11 and the long rural SAIFI target improves 29 percent.

EnergyAustralia has assessed the impact of capacity and asset condition driven programs to determine whether a residual gap remains, which needs to be addressed by a capital investment plan focussed on achieving specific reliability improvement.

EnergyAustralia has used two tools to determine the impact of investment programs on future reliability outcomes.

EnergyAustralia has modelled the reliability of subtransmission network areas using the failure rates of individual assets or asset types using AVSIM software. This information can be used to predict the reliability improvements that are likely as a result of asset replacement or as a result of a change in network configuration down to the zone substation level. A second tool has been used to calculate benefits of distribution network investment programs.[29]

Figure 4.9 shows the contribution that assets in different parts of the network make to overall reliability outcomes. It can be seen that 72 percent of minutes without supply is contributed by the distribution network, a further 9 percent is due to the low voltage network and 18 percent is contributed by the subtransmission network.

EnergyAustralia's Reliability Investment Plan (Attachment 4.9) demonstrates how this assessment has been conducted using both the AVSIM model (see Subtransmission Reliability Strategy Attachment 4.10) and the distribution reliability tool (see Reliability Investment Plan).

The development of the Reliability Investment Plan is discussed in Section 5.3.3.

29 The distribution network is too large to be modelled using AVSIM.

Figure 4.8: Improvement built into reliability standards (percent)

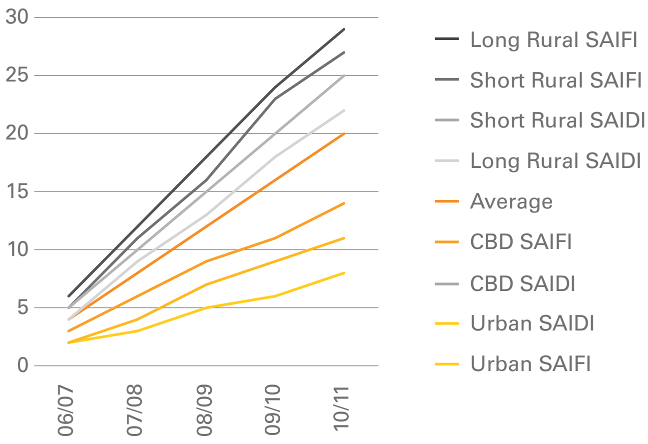
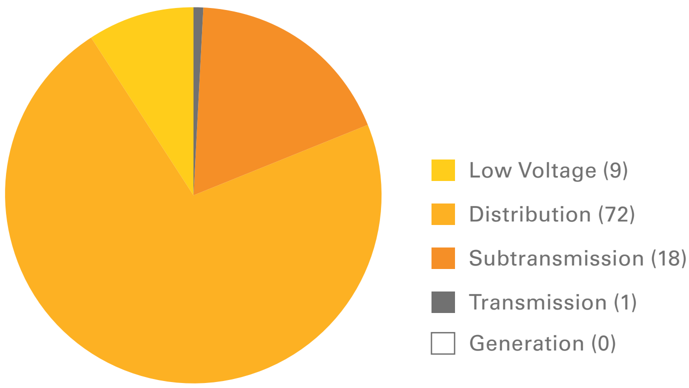


Figure 4.9: Contribution to EnergyAustralia's system reliability (percent)



4.3 Other network drivers

The following drivers relate to investment need that are not primarily aimed at achieving network performance and relate to EnergyAustralia's obligations to connect customers and meet standards regarding physical safety, environmental and related standards.

4.3.1 Connection of customers

Obligations

EnergyAustralia has clear obligations to provide access to its network services under the National Electricity Law and the Electricity Supply Act. Investment is driven by the number and the type of customers seeking connection to the network. This investment is therefore driven by the requirement to connect and supply third parties.

EnergyAustralia's customer connection obligation also extends to the provision of appropriate metering for new customers. All new EnergyAustralia customers with demand of less than 160MWh per annum are issued with interval meters. (The meter installation is a competitive function, but the meter provision is regulated for customers below the 160MWh threshold). The free issue of this material forms part of EnergyAustralia's expenditure requirements that is driven by customers connecting to the network. It should be noted that above 160MWh per annum customers have the choice of who provides the meter.

Investment necessary to comply with our connection obligations and meet associated demand and to provide appropriate metering infrastructure is consistent with the capital expenditure objectives, particularly the objective to meet or manage the expected demand for Standard Control Services.

Recent amendments to the National Electricity Rules require certain transmission connection services to be subject to a different form of regulation. This is limited to direct connections to the transmission network and represent only a minor portion of the costs associated with EnergyAustralia's obligation to provide access.

Details of the delineation between EnergyAustralia's negotiated distribution services and Standard Control Services are provided in EnergyAustralia's Service Classification and Control Mechanism Proposal.

Determining future customer connections

Forecasts of customer connection are typically difficult to predict with accuracy as they require insight into the behaviour and actions of third parties. Customer connections are generally linked with forecasts of economic activity, specifically activity in the building and construction sectors. Recent increases in interest rates, concerns about the sub-prime mortgage crisis in the US, its effect on credit markets, the potential for a US recession and the flow on impacts on Asian markets, and in turn Australian commodity markets, paints an uncertain economic picture for forecasters trying to determine Australia's future economic growth prospect.

EnergyAustralia's forecast expenditure on customer connections is also impacted by the type of connections made to the network. Individual connections can vary widely, from a domestic service wire to a large scale development that includes substations and high voltage connections. The forecast of the type of connection is therefore a critical factor in determining the overall expenditure requirement to address this driver.

4. EnergyAustralia's investment drivers (continued)

Circumstances

During the 2004-07 period, EnergyAustralia has experienced approximately 19,000 new customer connections annually. The number and cost of these connections has been responsible for $30 million expenditure above the regulated allowance for customer connections in the current period.

Figure 4.10 shows EnergyAustralia's expenditure on customer connections, as part of total customer contributed capital expenditure in the 2004-08 period.

The average annual number of new customer connections between 2001 and 2005 was 26,000 customers. Since 2005, there has been a significant fall in numbers of new customers connecting to the network which is largely consistent with the economic slow down seen in the Sydney and NSW market since that time.

Under an ex-ante framework EnergyAustralia will be penalised for expenditure above its allowance even though expenditure on customer connections is driven solely by the actions of third parties and the fact that EnergyAustralia cannot refuse to provide connection services due to its clear obligations under the National Electricity Rules and Electricity Supply Act.

EnergyAustralia does not believe that the economic slow down will continue indefinitely into the 2009-14 period, and has relied upon NSW Department of Planning data and reputable economic forecasters such as BIS Shrapnel who predict that economic activity will pick up before 2014 in order to relieve dwelling shortages in EnergyAustralia's network region.

EnergyAustralia engaged Evans and Peck to assist in establishing a robust forecast of customer connection expenditure. This process is outlined in Section 5.3.5.

4.3.2 Meeting modern infrastructure standards

Obligations

EnergyAustralia has legislative and regulatory obligations to provide distribution services and maintain electrical infrastructure in a manner that is safe for its workers, the general public and the environment.[30]

The obligation to maintain compliant infrastructure does not contribute to network performance per se (eg oil containment for a transformer does not improve the transformer's technical performance). However, it is critical to delivering a safe electrical network which is a key priority for EnergyAustralia.

EnergyAustralia constructs new infrastructure to comply with current standards. However, much of EnergyAustralia's infrastructure was built before current standards were introduced. Expenditure is necessary to bring older infrastructure to compliance.

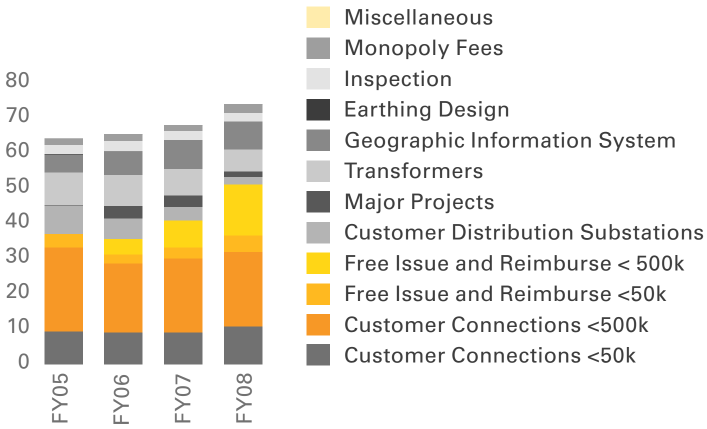
EnergyAustralia has identified three key areas of risk where assets may not meet current modern standards:

- Safety – covering both public and workplace safety risks, including fire prevention and risk mitigation strategies in relation to EnergyAustralia assets;
- Environmental – covering environmental compliance requirements including obligations in respect of waste disposal, pollution, contamination of land, remediation and environmentally hazardous chemicals; and
- Infrastructure risk – covering physical security and compliance risks relevant to EnergyAustralia's network assets.

Investment driven by the need to comply with modern standards is consistent with the capital expenditure objective of maintaining the reliability, safety and security of the distribution system. It is also necessary to meet the capital expenditure objective of compliance with regulatory obligations or requirements associated with the provision of Standard Control Services.

30 These legislative and regulatory obligations are detailed in Attachment 4.1.

Figure 4.10: Customer contributed Expenditure 2004-08 ($m nominal)



Assessing future needs

EnergyAustralia has undertaken a gap analysis to determine the locations and types of assets that do not meet current industry safety standards. The gap analysis begins with a list of known non-compliances. Surveys of particular asset types are usually conducted to ensure that the full scope of the non-compliance has been properly identified. Following the survey, a program of works is developed to ensure that the non-compliances are addressed within reasonable timeframes and projects are prioritised according to risks.

EnergyAustralia's environmental risks encompass a variety of issues. Major issues include preventing oil contained in network equipment from leaking into the environment. A risk assessment of all major sites has been carried out and programs are underway to address identified risks.

A security risk assessment has also been carried out for major infrastructure. This assessment has been undertaken in conjunction with Commonwealth and State security agencies that have identified sites of particular security interest.

EnergyAustralia's public and workplace safety issues are monitored through a variety of mechanisms. Programs are developed to address issues as they are raised. In response to concerns about public access to substation sites, EnergyAustralia embarked on a comprehensive upgrade of substation fencing to ensure that public access was minimised in order to protect unwitting entrants from live equipment.

Circumstances

EnergyAustralia has invested heavily in the 2004-09 period to ensure its network meets modern standards for public and environmental safety, and modern infrastructure security measures. Most of the expenditure in the 2004-09 period has occurred in the subtransmission network. In contrast, the 2009-14 period is characterised by a greater focus on similar issues in the distribution network.

4.4 Business drivers – delivering operational efficiency

EnergyAustralia has identified three categories of business support investment that are driven by the need to deliver operation efficiency. These are:

- fleet costs;
- information technology and business development; and
- investment in corporate property.

These investments facilitate the operation of the network business and are essential requirements that enable EnergyAustralia's continued delivery of optimal and efficient operations.

4.4.1 Fleet

EnergyAustralia's business model incorporates an internal service provider that undertakes all maintenance and electrical work on the network. Fleet costs are significant given the geographical disbursement of EnergyAustralia's network assets and the type of work undertaken by our internal service provider.

It is essential that our service provider is appropriately equipped to respond quickly and effectively to network needs. Fleet requirements include a substantial fleet of vehicles as well as specialist equipment such as elevated work platforms (EWPs), trucks and pole erectors.

Obligations

EnergyAustralia has OH&S and work place safety obligations and must make appropriate equipment available to staff to undertake their jobs.

It is essential to have an appropriately equipped and flexible workforce so that faults and interruptions can be attended to as quickly as possible, and in a safe and efficient manner.

Fleet expenditure is integral to EnergyAustralia being able to deliver high quality, reliable and secure Standard Control Services to its customers and maintain reliability, safety and security of its network. Appropriate investment in fleet directly impacts the efficiency with which EnergyAustralia is able to meet the capital expenditure objectives.

4. EnergyAustralia's investment drivers (continued)

Assessing future fleet needs

EnergyAustralia's expenditure on fleet is based on a cycle of vehicle renewal based on standard lives or kilometre rates. Strategic refurbishment of large equipment such as EWPs and crane borers takes place. However, for smaller equipment, vehicles are replaced when they reach certain operating limits.

EnergyAustralia's vehicle fleet consists of 1300 leased vehicles, 1700 owned vehicles and 720 owned mobile plant. All cars, station wagons and some utilities with minimal equipping are leased to conserve capital for light commercial, truck and plant acquisitions.

Fleet forecasts for the 2009-14 period have been developed taking into consideration several factors that will impact future costs:

- the planned replacement cycle;
- changing costs of equipping vehicles;
- changes in work practices and multi-skilling that may drive changes to equipping costs;
- costs associated with providing higher levels of vehicle safety (eg light commercial vehicles are supplied with ABS brakes and air bags where available); and
- delays in the replacement of vehicles.

Circumstances

In planning for an increase in the system capital program, EnergyAustralia has allowed for a corresponding increase in its specialised fleet to enable it to facilitate its supply of Standard Control Services. It has also allowed for replacement of existing fleet, some of which has been deferred from previous periods, but is largely driven by EnergyAustralia's desire to return to a replacement cycle in line with industry practice.

4.4.2 Network information technology and business development

Obligations

EnergyAustralia is obliged to operate IT systems that are sufficiently sophisticated to manage a large and complex business.

EnergyAustralia has obligations to provide accurate financial reports to its shareholder and other bodies and has obligations to NEMMCO to provide market data. EnergyAustralia needs appropriate IT systems in place to comply with these obligations. Appropriate IT investment also facilitates efficient business operations which enables EnergyAustralia to deliver Standard Control Services in a manner consistent with the capital expenditure objectives.

Forecasting future IT needs

The methodology used to forecast IT requirements is based on a thorough examination of existing IT infrastructure and an assessment of future needs. This assessment includes a systematic investigation of factors that are likely to influence IT scope in the future, changes in costs over the period, and analysis of whether new functions will be required.

The IT strategy has been developed using a bottom-up analysis that links IT requirements to ongoing network and business needs.

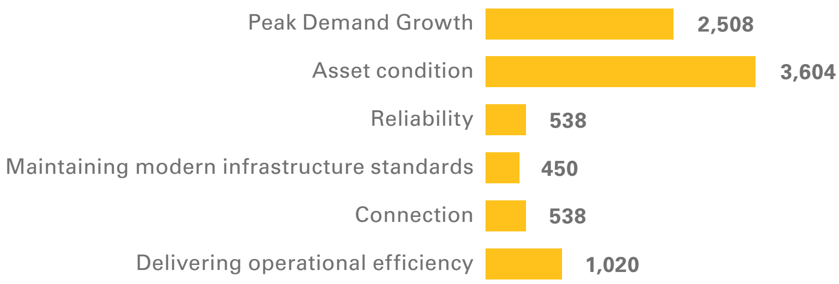
Circumstances

EnergyAustralia has invested heavily in IT systems in the 2004-09 period. However, this investment falls short of IT system depreciation and therefore does not reflect the true renewal requirements of the business over the last five years.

EnergyAustralia is in the process of implementing a new integrated Asset Management System (iAMS) which, when fully operational, will enable the business to better link asset and financial data and thereby improve the quality of asset and financial management decisions.

EnergyAustralia's Network Operational Technology Plan is discussed in detail in Section 5.3.9 and provided as Attachment 4.11.

Figure 4.11 EnergyAustralia's capital expenditure by driver for 2009-14 (FY09 $m real)



4.4.3 Corporate property

Efficient business operation requires an appropriate working environment. This includes adequate provision of professional work spaces for both office and field based staff. Many of EnergyAustralia's existing property holdings no longer provide an appropriate work environment.

Obligations

EnergyAustralia has an obligation to provide a safe work environment for its employees. EnergyAustralia's policy is that workers throughout the business should be able to access a professional and consistent standard of office accommodation and equipment.

A skilled workforce is essential to successfully operate EnergyAustralia's distribution network, to manage its investment program and to deliver Standard Control Services in a manner consistent with the capital expenditure objectives. Investment to retain skilled staff is consistent with these objectives and enables EnergyAustralia to comply with our legislative and regulatory obligations.

Forecasting future property requirements

EnergyAustralia's property strategy presents a business wide examination of property requirements. There are several drivers for investment in property within EnergyAustralia including:

- new facilities for system security and operation purposes;
- consolidation of depot and regional property needs;
- office accommodation to house growing staff numbers; and
- upgrade of existing office accommodation facilities to modern and consistent standards across the business.

The strategy is based on a set of six planning principles outlined below:

Tenure: EnergyAustralia intends to retain ownership or purchase property where there is a clear, long-term need for the facility to support business processes and the cost of occupancy is beneficial. However, EnergyAustralia would lease property where the need is unclear or short-term and the cost of occupancy is commensurate with alternatives.

Function: EnergyAustralia intends to occupy buildings that provide fit-for-purpose, safe and effective workplaces across the franchise area.

Location: EnergyAustralia plans to accommodate staff in locations that support proximity to assets, appropriate zoning and servicing of customers.

Image: EnergyAustralia intends to improve the property portfolio to portray an image that is professional, consistent across the franchise, and appropriate to the function.

Financial: As far as possible, any new investment in properties will be funded from the sale of redundant or unsuitable holdings.

Environmental: EnergyAustralia will strive to achieve sustainable development in all new facilities and to improve environmental performance in all existing facilities.

EnergyAustralia's Corporate Property Strategy is discussed in detail in Section 5.3.9 and can be found at Attachment 4.12.

4.5 Capital program by driver

The Rules require EnergyAustralia to present its capital forecast by reference to well accepted categories such as drivers. Figure 4.11 shows the contribution of each driver to the overall capital program proposed for the 2009-14 period.

4.6 Conclusion

This chapter provides an overview of the investment drivers which arise from the capital expenditure objectives and regulatory obligations that EnergyAustralia must meet. EnergyAustralia uses these to inform its capital planning process. The primary drivers of capital expenditure over the period are as follows:

- network performance;
- customer connections;
- maintaining modern infrastructure standards; and
- maintaining operational efficiency.

The chapter goes on to outline how those drivers are used in EnergyAustralia's current circumstances, to assess the future capital expenditure needs of the organisation.

Finally, the relative proportions of capital expenditure associated with these drivers over the upcoming regulatory period are outlined.

CAPEX

5. Strategic capital development

The purpose of this chapter is to outline EnergyAustralia's approach to developing a prudent and efficient capital program by using a strategic network capital development process. The process is based on prudent planning and utilises efficient project costs and planning policies to deliver a capital proposal that meets our obligations and the expenditure objectives outlined in Chapter 3.

This chapter highlights the two stage process that EnergyAustralia has used to forecast its capital program. The first stage identifies network requirements at an investment driver level. The second stage uses the outputs from the first stage – the list of required investment needs identified for each driver – as inputs to the strategic planning process. The outcome of this second stage is a suite of investment plans that form the basis of our capital forecast for the 2009-14 period.

Section 5.1 outlines the key assumptions and inputs that are used in developing the capital plan.

Sections 5.2 explains the process that EnergyAustralia undertakes to plan capital investment.

Section 5.3 summarises the plans that EnergyAustralia produces as a result of its capital development process.

Section 5.4 explains the adjustments made to the sum of the capital investment plans to produce the annual capital expenditure forecasts.

Section 5.5 outlines EnergyAustralia's multi-prong approach to delivery of the 2009-14 capital investment program.

Section 5.6 describes EnergyAustralia's approach to escalating costs over the regulatory control period.

5.1 Inputs and assumptions to the strategic network capital development process

Table 5.1 indicates that plans are informed by projected investment triggers and cost inputs which themselves are based on underlying assumptions of changes to current circumstances over the period.

The key assumptions underlying EnergyAustralia's capital forecast are included in EnergyAustralia's response to the AER's regulatory information template 2.3.3.

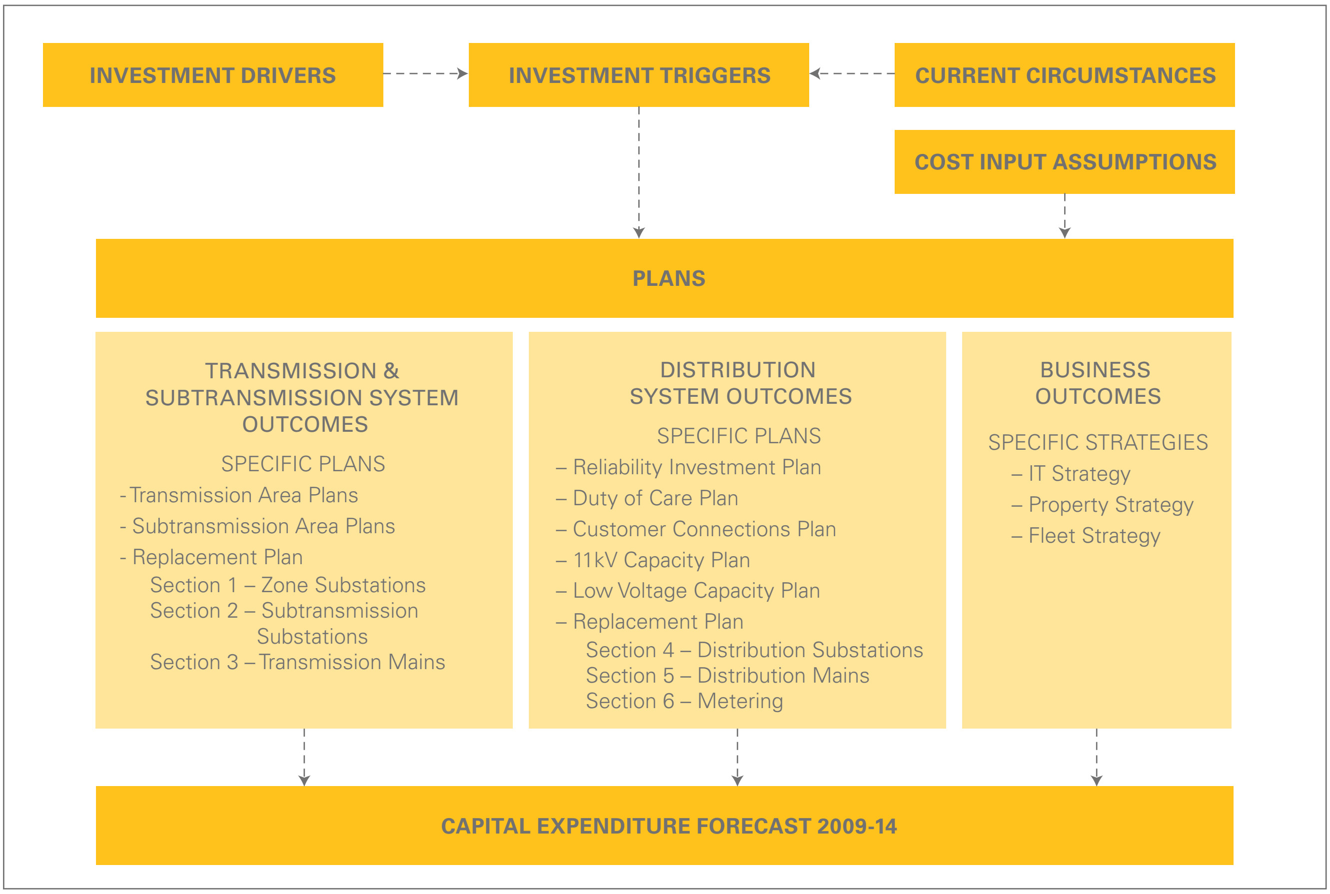
In accordance with the Rules, these assumptions have been certified as reasonable by EnergyAustralia's Directors. The Directors' certification accompanies the Building Block Proposal.

Key inputs to the costing stage in the process include:

- standard greenfield cost estimates based on recent EnergyAustralia experience and verified by external consultants;
- non-standard adjustments/premiums that are added to projects where chosen options are brownfield projects; and
- cost escalation factors to be applied to all program costs to ensure real cost increases are captured within the capital forecast.

The rest of this chapter outlines the strategic process that EnergyAustralia has used to develop its capital investment plans which form the basis of the capital proposal.

Table 5.1: Capital planning process



5. Strategic capital development (continued)

5.2 Strategic capital development process

This section outlines the process EnergyAustralia undertakes to plan capital investments in response to the investment drivers described in Chapter 4.

The output of this process is a set of plans which are costed and together form the forecast expenditure for the next regulatory control period. Each plan is outlined in Section 5.3 below.

EnergyAustralia has used a strategic approach to develop its capital expenditure forecast for the 2009-14 period. This is driven in part by the extent of capital investment required in the period, but is largely driven by a need to develop efficient strategic decisions that ensure outcomes are prudent and are delivered at the lowest cost over the life of the assets.

These forecasts encapsulate the network needs and set the quantum and location of investment required during the period. However, to ensure EnergyAustralia's capital forecast is prudent and efficient, a variety of investment options that address the network needs must be considered (where possible) as well as the relative costs of these different investment approaches.

Analysis of investment options, and costs, is a critical component of EnergyAustralia's strategic planning process.

As noted at the beginning of Chapter 3, EnergyAustralia divides its network into distinct parts for identifying investment requirements and capital planning purposes:

Transmission network – is the network that operates in support of TransGrid's 330kV system. These overhead and underground 132kV feeders connect EnergyAustralia's major substations to TransGrid's BSP's and to each other.

Subtransmission network – comprises zone and subtransmission substations and the network which supplies these substations. It is made up of overhead and underground feeders that operate at 132kV, 66kV and 33kV.

Distribution network – is made up of the distribution network (mainly 11kV) and the low voltage network (415/240V) which distributes energy from zone substations via distribution substations, kiosks, etc to customers. Compared to the transmission and subtransmission networks, distribution network assets are larger in number, smaller in size, generally less expensive (per asset) and less significant in terms of failure and consequence.

EnergyAustralia has planned developments within the transmission and subtransmission networks by breaking the network into 25 geographic areas. All drivers of investment within each area have been considered together and each subtransmission asset within the area has been assessed for its demand capacity balance, its condition, its contribution to reliability performance and whether it is likely to be impacted by a new large customer connection.

EnergyAustralia's approach in the distribution network utilises forecasting models, statistical analysis and asset population risk assessment to develop capital investment requirements. Capital investment plans in the distribution network are based on a single driver of investment (rather than multiple drivers which applies at higher levels of the network).

Table 5.2: Strategic capital investment plans (FY09 $m real)

Network	Plan	Driver	EnergyAustralia's investment Criteria	Cost	Meets Objective
Transmission network	Transmission Area Plans (3 plans)	Peak demand growth, replacement, modern standards, network reliability & customer connections (across multiple areas)	Jointly agreed Reliability Planning Criteria	443	1,2,4
Subtransmission network	Subtransmission Area Plans (25 plans)	Peak demand growth, replacement, modern standards, network reliability & customer connections (within a single area)	DRP Schedule 1 - Design, Planning Criteria	3,506	1,2,4
Transmission network (components only) Subtransmission network (components only) Distribution network	Replacement Plans	Asset condition	Condition & risk assessment	1,828	2,3,4
Distribution network	Reliability Investment Plan	Reliability	DRP Schedule 2 & 3 Individual customer black spot criteria	79	2,3,4
Subtransmission network (components only) Distribution network	Duty of Care Plan	Meeting modern infrastructure standards	Risk assessment	285	2,3,4
Distribution network	Customer Connections Plan	New connections	Customer connection application	504	1,2
Distribution network	11kV Network Development Model	Peak demand growth	DRP Schedule 1 – Design, Planning Criteria	698	1,2,3
Distribution network	Low Voltage Capacity Plan	Peak demand growth	EnergyAustralia criteria based on Design, Planning Criteria	295	1,2,3
All Network levels	Network Communications & Technology Plan and other business support investments	Operational efficiency	Identified opportunities for improvements	1,020	1,2,3&4
Total Forecast				**8,659**	**1,2,3&4**

5. Strategic capital development (continued)

5.3 Strategic capital plans

This section summarises the plans that EnergyAustralia produces as a result of its capital development process. These plans are costed using the cost input assumptions described in the next section. The totality of plans represents EnergyAustralia's total capital expenditure requirement for the 2009-14 period (summarised in Table 5.2).

5.3.1 Area Plans

The cornerstone of EnergyAustralia's capital forecast for 2009-14 is the 25 Subtransmission Area Plans and the three Transmission Area Plans (found at Attachment 5.1). These plans represent an efficient, long term, strategic view of the network and outline a 20 year program of works required to meet known asset performance requirements, new large connections, infrastructure standard compliance gaps and likely capacity constraints.

The Area Plans represent a step change in planning sophistication and analysis for EnergyAustralia as they can be used to predict capacity constraints up to 20 years in advance and allow strategic investment decisions to be made in the short term to ensure lowest cost solutions are delivered over the long term.

Each Area Plan focuses on a geographic area of the network and incorporates all strategic capital expenditure requirements within that area of the subtransmission or transmission network. The Area Plans and their contribution to the capital forecast are listed in Tables 5.3 and 5.4.

Included in Table 5.4 are conditional projects which may be required as a result of:

- Third party requirements
  - major residential or customer developments
  - availability of power station auxilary supplies
- Acceleration of equipment replacement.

Conditional projects are also costed using the network development strategy costing model. The cost is then multiplied by the probability of the project proceeding in order to arrive at a realistic expectation of the overall cost, which is aggregated into the proposed capital expenditure program for the regulatory control period.

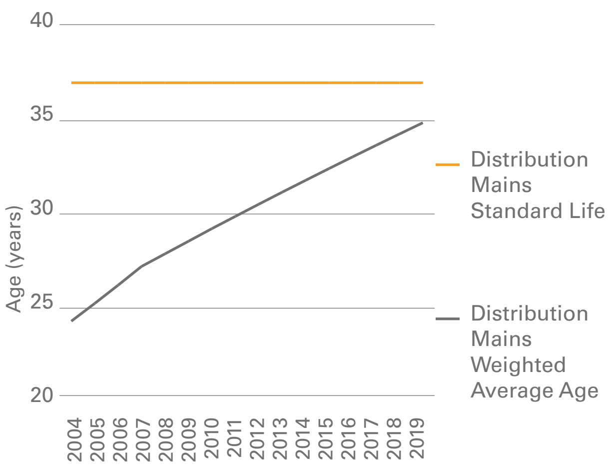
Table 5.3: Transmission Area Plan contribution to total forecast (FY09 $m real)

Transmission Area Plans	Costs in 2009-14
Inner Metropolitan Area	357
Central Coast	10
Lower Hunter	76
Total	**443**

Table 5.4: Subtransmission Area Plan contribution to total forecast (FY09 $m real)

Subtransmission Area Plans	Costs in 2009-14
Camperdown and Blackwattle Bay	87
Canterbury Bankstown	181
Carlingford	76
Central Coast - Lower	169
Central Coast - Upper	101
Cessnock	88
Eastern Suburbs	263
Hunter - Upper	143
Inner West	247
Lake Macquarie - North-East	62
Lake Macquarie - West	68
Maitland	80
Manly Warringah	121
Newcastle CBD	95
Newcastle Ports	92
Newcastle Western Corridor	24
North Shore - Lower	261
North Shore - Upper	63
North West Sydney	9
Pittwater and Northern Beaches	14
Port Stephens	116
Singleton and surrounds	19
St George	113
Sutherland	168
Sydney CBD	612
Conditional Projects	66
Land	169
Total	**3,506**

Figure 5.1 Change in weighted average age of distribution mains over time



Replacement requirements that have synergies with other drivers have been incorporated into Area Plans. This occurs at the subtransmission and transmission level (all other replacement requirements are incorporated in the Replacement Plan).

Replacement of the following assets are considered to have synergies with other drivers as their replacement triggers significant capital investment and can create opportunities to enhance capacity while being replaced:

- 132kV oil filled cables;
- 33kV gas filled cables; and
- 11kV switchgear.

EnergyAustralia's Area Plans were developed two years ago and were reviewed for the Regulatory Proposal. The key inputs to each plan include:

- spatial forecasts for each zone and subtransmission substation within the area which identifies future capacity constraints;
- condition based replacement prioritisation for strategic assets within the area;
- duty of care concerns within the area;
- known large customer connections; and
- locations where reliability criteria are not met.

Each plan contains a summary of network needs within the area and outlines up to four investment strategies developed to address the network needs to 2024. Multiple strategies were developed for each area to ensure that the chosen strategy represented the most efficient cost of meeting the network needs over time. EnergyAustralia undertook this analysis to apply the principles of the regulatory test in a more strategic manner than is typically applied. The analysis showed that in several cases, strategies that appeared cheaper in the short term proved to be more expensive when longer term considerations were taken into account.

Each plan outlines why a strategy is chosen over others and how the strategy meets the network requirements.

The strategies chosen, and the project lists that result, represent the investments that would be chosen by a prudent DNSP in similar circumstances.

EnergyAustralia has forecast an average growth rate in summer peak demand of approximately 2.8 percent per annum in the period 2009-14 for the whole of the franchise area (based on econometric forecasts).

This average growth rate varies between regions within EnergyAustralia's network and within regions there is significant variation of peak demand growth rates between zone substations. In some areas, zone growth rates (spatial forecasts) are in excess of six percent. Higher growth rates are typically linked to local area development and air conditioning penetration.

The spatial forecasts are used to forecast the timing of installed capacity constraints and are described in Section 4.2.1. This forecast triggers either a supply-side or demand-side network investment.

The Design Planning Criteria requires EnergyAustralia to maintain network security of N-1 in general, together with "load at risk" limits. Ongoing growth in peak demand that is not matched with capacity investment will erode network security over time and result in higher levels of load at risk.

Transmission network: EnergyAustralia jointly plans its transmission network with TransGrid. The Design Planning Criteria contained in Schedule 1 of the DRP licence conditions do not apply to TransGrid. However, EnergyAustralia and TransGrid have jointly agreed reliability criteria based on an enhanced N-1 security. The jointly agreed transmission planning criteria are included at Attachment 5.2.

Subtransmission network: EnergyAustralia's subtransmission network has been designed with N-1 security. The calculation of load at risk incorporated in the licence conditions is slightly lower than that previously applied by EnergyAustralia. The conditions do not allow any load at risk on certain types of equipment such as underground subtransmission feeders. The introduction of the DRP licence conditions has had the effect of reducing effective firm capacity in some locations.

5. Strategic capital development (continued)

CBD network: The licence conditions also mandate an N-2 security standard for the network supplying Sydney's CBD. This must be achieved by 2014 where practicable and is a significant driver of capital expenditure in the 2009-14 period. This expenditure is driven not by capacity constraints per se, but by a new higher standard of security (the change from N-1 to N-2).

Strategic development of Area Plans

EnergyAustralia's approach to developing its Area Plans is documented in Attachment 5.3 Area Plan Development Process, and is summarised below.

The Area Plan development process included an in-depth analysis of project scope, feasibility and cost. All projects within each strategy considered as part of the Area Plan process have been reviewed by senior planners and design engineers to confirm each projects scope and feasibility.

Projects were estimated by EnergyAustralia's forecasting experts based on standard "greenfield" building blocks. Allowances were included where necessary for specific site factors (i.e. sloping ground, wetlands, environmental issues etc). Where "brownfield" work was forecast, premiums based on historical costs were added to ensure that project costs reflect the substantially higher cost of working in and around existing equipment. These premiums vary depending on project type and local conditions.

The Area Plans outline $3.9 billion of proposed investment in the transmission and subtransmission network for the 2009-14 period and are shown in Tables 5.3 and 5.4. An overview of the costing methodology can be found in Attachment 5.4 – The Costing Basis for Buliding Block Estimates Process Overview.

5.3.2 Replacement Plan

EnergyAustralia's Replacement Plan incorporates all replacement driven capital expenditure on assets that are not included in the Area Plans. The assets included in the Replacement Plan are therefore predominantly in the distribution network (i.e. the network below the 11kV busbar) but the Plan also includes component parts of the transmission and subtransmission network such as overhead lines, insulators, and the like, which do not impact on planning strategies and therefore are not included in the Area Plans.

EnergyAustralia's Replacement Plan 2009-14 (Attachment 4.8) contains a consolidated view of asset condition and replacement requirements throughout the network.

The Replacement Plan contains a description of each program of work that has been developed, is currently being implemented, or is proposed to address the asset condition issues that have been identified through condition based monitoring, maintenance and risk assessments. The Replacement Plan contains all known replacement requirements as at February 2008.

The costs within the Replacement Plan are broken into the following categories:

- Reactive programs – programs designed to replace assets that fail whilst in service. This is based on historical failure rates and the historical cost of reactive replacement for each type of equipment. This is non-discretionary expenditure.
- Planned programs – programs of proactive work that have been authorised, are currently underway and that will continue into the 2009-14 period.
- Proposed programs – programs that have been identified as being required during the 2009-14 period, but have not yet started. This type of program would be used where increasing failure rates have been identified and a decision has been made to remove this type of asset from the network over time. This type of program changes an ad hoc reactive expenditure into a proactive program of replacement works.

These categories are important as they show the level of maturity of the replacement program and can be compared to asset performance over time. For example, as asset failure rates increase, asset managers move expenditure from reactive programs to planned programs of systematic replacement to manage asset performance outcomes.

Figure 5.2: EnergyAustralia's SAIDI[31] performance

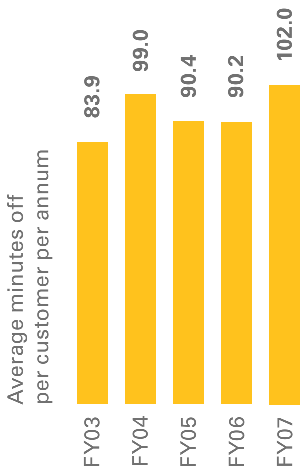
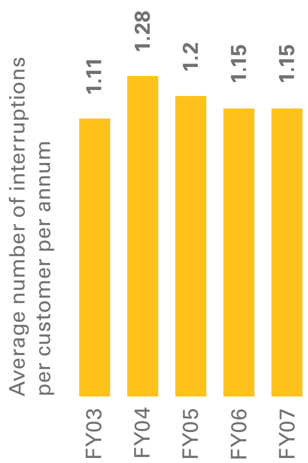


Figure 5.3: EnergyAustralia's SAIFI[32] performance



Current performance

EnergyAustralia has the oldest network in Australia with approximately 15 percent of assets currently in service beyond their standard design lives. Assets are designed with certain specifications to meet a design life. Where assets perform outside these parameters, their performance cannot be relied upon without ongoing monitoring and risk assessment.

In some cases, older assets show minimal signs of deterioration. This is true for EnergyAustralia's 33kV HSL cables which continue to perform well, despite being in service 20 years beyond their design life. By 2014, EnergyAustralia will have HSL cables that are more than 87 years old. In contrast, there are other assets that display signs of deterioration well before they have reached their standard life. EnergyAustralia's gas insulated 33kV cables are in poor condition well before they have reached their design life.

EnergyAustralia has noted elsewhere in this proposal that, while not an accurate indicator of an asset's condition, age can signal a heightened level of risk for an asset, particularly where large volumes of assets within a population are approaching, or have exceeded, their design life.

Assessment of asset condition and risk to the network ensures efficient economic decision making.

Asset replacement is the major driver of EnergyAustralia's capital program in 2009-14. The large number of replacement projects proposed by EnergyAustralia reflects the inevitable reality of asset renewal resulting from the post war investment boom in electrical infrastructure and the level of investment in asset replacement that occurred in the 1980s and 1990s.

Strategic development of the Replacement Plan

Investment managers make their decisions to replace or repair assets, or to let the asset run to failure based on a detailed risk assessment. EnergyAustralia uses a risk matrix (incorporated in its Maintenance Requirements Analysis Manual) to quantify failure frequency and the consequence of asset failure. Risks that are reviewed include:

- safety;
- environmental;
- reliability;
- property damage; and
- liability claims.

Where appropriate, detailed investigations are commissioned to ensure that trends identified through data analysis are supported by system wide surveys of asset condition. Using this detailed condition assessment, assets are identified for replacement and prioritised based on the risk analysis.

Results

EnergyAustralia's proposed programs of asset replacement represent a step change to a higher and sustained level of asset renewal that will continue into the 2014-19 regulatory period and beyond.

In the 2009-14 period, critical assets such as 11kV switchgear and 132kV oil and 33kV gas filled cables are being targeted for replacement as they represent key risks to the system.

EnergyAustralia has approximately 250 kilometres of underground gas pressure cable and 450 kilometres of underground oil filled cable. The cost and difficulty of replacing these assets is such that EnergyAustralia considers that a 15 year program will be required to replace the gas pressure cables and a 20 year program will be required to replace the oil filled cables. The worst performing cables are being targeted for replacement in the 2009-14 period. If replacement of these assets is not targeted in the 2009-14 period, opportunities to undertake this work in the future will be very limited due to loading on these assets, which in some cases form critical parts of the subtransmission network. Replacement, if deferred, will lead to sub-optimal price and network outcomes for customers.

31 SAIDI – System Average Interruption Duration Index based on IEEE standard 1366-2003.

32 SAIFI – System Average Interruption Frequency Index.

5. Strategic capital development (continued)

Replacement of these key strategic assets is incorporated in the Area Plans. However, it should be noted that asset plan replacement contributes almost half of the replacement driven expenditure forecast by EnergyAustralia.

The 2009-14 period represents a window of opportunity to undertake significant and strategic replacement of assets to curb network risk and also install new assets that have better performance and greater capacity. This is particularly true for EnergyAustralia's transmission and subtransmission networks.

The window of opportunity relates to the ability to access the current transmission and subtransmission networks to allow connection of new assets outside the peak usage periods of our network. These peak periods in summer and winter are elongating and by definition the periods of access are closing for a prudent DNSP to take out elements with the avoidance of customer impacts if there is a further failure while the first is out for connection of the new asset.

The Replacement Plan incorporates a significant increase in expenditure on distribution assets, particularly in distribution substations and low voltage cables. Despite this increase in expenditure, the average age of distribution equipment will continue to increase over the 2009-14 period. Figure 5.1 shows that the weighted average age of assets in the distribution mains group increases from 28.22 to 31.47 years over the period. If no investment was made the average age at the end of the period would be 33.22 years. EnergyAustralia expects that replacement expenditure on the distribution system will increase substantially from 2014.

Costing the Replacement Plan

The costs within the Replacement Plan have been developed based on analysis of historic costs. Planned replacement work has been checked by EnergyAustralia estimators to ensure that costs on average reflect brownfield construction limitations and cost premiums.

Premiums have been added to the costs of "reactive" replacement program (relative to planned work) because reactive work typically involves emergency works which may entail temporary work to restore supply in the short term as well as work to permanently repair equipment. The basis for project costs is outlined in the Replacement Plan and the total cost of the Replacement Plan is shown in Table 5.5.

Table 5.5: Replacement Plan (FY09 $m real)

Distribution centres	344
Zone substation	253
Transmission substation	120
Distribution mains	963
Transmission mains	92
Other	55
Replacement Plan	**1,828**

The Replacement Plan is driven predominantly by distribution mains. This level of expenditure is considered to be the start of a much larger program of distribution focussed replacement that will be required in future periods.

5.3.3 Reliability Investment Plan

EnergyAustralia's Reliability Investment Plan (Attachment 4.9) outlines the methodology used to calculate the gap between network performance, that will result from the capital investment programs, and the reliability performance as required by the DRP licence conditions.

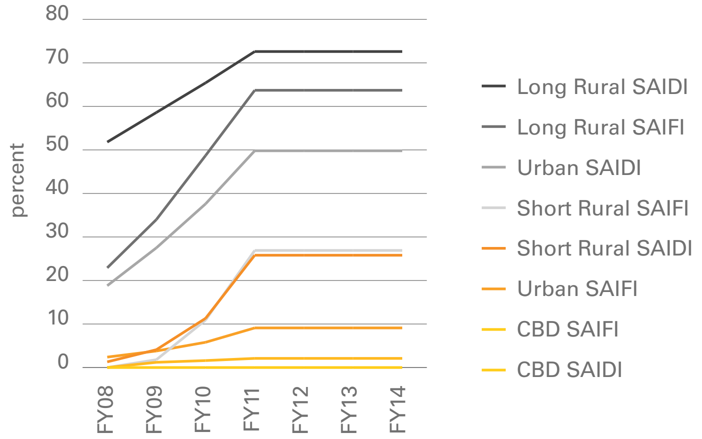
The gap is determined through statistical analysis of past performance and predictions of future network performance.

The performance gap is translated into a quantum of work required which is prioritised on the basis of individual feeder performance while ensuring sufficient funding for the individual feeder requirements in Schedule 3.

The Reliability Investment Plan is determined by understanding the starting point of system reliability after assuming all investments are made in the Area Plans and Replacement Plans.

The methodology used to calculate the benefits of other plans is outlined in detail in the Reliability Investment Plan.

Figure 5.4 Probability of non-compliance for feeder categories with Schedule 2 licence conditions if current performance is maintained



Current performance

EnergyAustralia's network performance has remained relatively stable in recent years as shown in Figures 5.2 and 5.3. System average SAIFI is relatively constant over the period which is a significant achievement considering the increasing age and failure rates of some network equipment. Average SAIDI is also relatively constant. However, this level of performance cannot be relied upon to continue in future in the absence of significant investment given the age and condition of key equipment.

The licence conditions set out average performance in Schedule 2 for customers, and individual feeder performance in Schedule 3 by distribution feeder type (i.e. CBD, Urban, Short Rural or Long Rural).

EnergyAustralia has analysed the risk of non-compliance in the future by directly comparing the SAIDI and SAIFI probability distributions against the Schedule 2 Reliability Standards without the capital expenditure program. The comparison shows the risk of non-compliance in any one year and the results are presented in Figure 5.4. The probability of non-compliance rises over time to reflect the fact that the performance requirements become more stringent up to 2011-12.

In the Urban feeder category, EnergyAustralia faces a significant emerging SAIDI compliance risk. In Short Rural, a SAIDI and SAIFI compliance risk is emerging, while in Long Rural there is a significant existing, and worsening, compliance risk for both SAIDI and SAIFI.

Individual customer reliability

The DRP licence conditions do not focus on the reliability experienced by individual customers.

Schedules 2 and 3 in the licence conditions focus on the average feeder category and individual feeder level performance respectively. Averaged performance metrics like these may not adequately reflect individual customers who experience poor reliability in pockets of the network. This is particularly the case when a feeder has a lot of segmentation through the use of line reclosers and fuses. Average feeder performance will reflect the reliability seen by a majority of customers on the feeder – typically the larger numbers closer to the zone substation who are subject to less feeder exposure and less faults. Smaller numbers of customers further away from the zone substation can experience significantly poorer reliability performance. Their feeder supply from the zone is longer and subject to more exposure to faults.

Individual customers on a feeder do not experience average performance, they experience their own particular performance, and poor individual customer reliability performance can result in significant customer dissatisfaction.

EnergyAustralia has filled the individual customer gap in the DRP licence conditions through the development of a "black spot" reliability program. Reliability black spots are identified through the use of internal Individual Customer Reliability Thresholds. These Individual Customer Reliability Thresholds for annual outage frequency and maximum outage duration were empirically chosen at two to three standard deviations away from the average levels of individual customer reliability – a point chosen to flag poor individual customer performance. An exceedence of these thresholds is a flag to investigate individual customer reliability performance and, in some cases, to initiate appropriate reliability improvements.

This black spot reliability program allows EnergyAustralia to rectify the reliability performance of small pockets of the network that would not be addressed if the sole focus was on the Schedule 2 and 3 licence condition requirements.

5. Strategic capital development (continued)

Table 5.6: Indicative individual customer minimum service standards

	Frequency Off Per Annum	Maximum Outage Duration Hrs (minutes)
CBD	2	7 (420)
Urban	5	7 (420)
Short Rural	10	10 (600)
Long Rural	14	16 (960)

Results

EnergyAustralia has identified a reliability gap between projected network reliability performance and the level of performance that will deliver a five percent risk of non-compliance with each of the reliability standards (after accounting for benefits in other plans) in any one year.

EnergyAustralia's Reliability Investment Plan contains projects that will address the reliability gap between expected future network performance that will result from meeting capacity constraints, asset condition and new customers, and the level of performance required to achieve compliance with Schedule 2 and 3.

The investments outlined in the Reliability Investment Plan aim towards meeting requirements of Schedule 3 (Individual Feeder Standards) and ensure EnergyAustralia reaches an acceptable risk of non-compliance with Schedule 2 (Reliability Standards). The plan also contains an individual customer component to address pockets of poor network performance to individual customers.

The Reliability Investment Plan has been estimated using historic costs for similar projects as a starting point. Where appropriate, the greenfield standard building block estimates have also been used.

The investment required to address the "gap" of network performance, after all other investment drivers have been addressed, is $79 million over the 2009-14 period. Table 5.7 provides a breakdown of expenditure for the Reliability Investment Plan.

Table 5.7: Reliability expenditure 2009-14 (FY09 $m real)

Reliability program	
Average System Standards	33
Individual Feeder Standards	30
Individual Customer Standards	16
Total	**79**

Further details are included in the Reliability Investment Plan.

5.3.4 Duty of Care Plan

EnergyAustralia's Duty of Care Plan contains works that ensure our network meets modern infrastructure standards. It has a similar format to the Replacement Plan. The Plan has been developed by assessing asset types and using surveys of installed equipment. Non-complying assets have been prioritised through risk assessment. The result is a systematic program to address risks and ensure asset compliance with modern standards for that asset type.

The Duty of Care Plan is included as Attachment 5.5.

Current performance

EnergyAustralia's network has been built over the course of 100 years. All new installations are built in accordance with industry and Australian Standards for electrical infrastructure and civil works together with industry codes and prudent engineering practice. However, these standards have changed over time, and there are installations still in service that, despite being built to meet standards in place at the time, do not comply with current standards. This is particularly true in relation to fire prevention and infrastructure security.

EnergyAustralia has a commitment to ensure that its network assets meet appropriate standards. During 2004-09, EnergyAustralia has invested heavily to achieve these compliance outcomes which have largely been achieved in the subtransmission network. EnergyAustralia intends to focus on delivering similar compliance outcomes in the distribution network during the 2009-14 period.

The compliance focus for 2009-14 is on appropriate management of asbestos in the distribution network, oil containment in distribution centres, and asset security.

Costs incorporated in the Duty of Care Plan have been estimated using historic costs as a starting point. Where appropriate, the greenfield standard building block estimates have been used.

Based on the strategic network capital development process explained above, the Duty of Care Plan contains $285 million of investments over the period. The Area Plans incorporate some aspects of compliance with modern standards but, as in all cases, care has been taken to ensure there is no cost overlap between the plans.

5.3.5 Customer Connection Plan

EnergyAustralia's Customer Connection Plan (Attachment 5.6) has been developed with the assistance of Evans & Peck. A forecast of customer connection volumes has been developed using economic analysis and NSW regional planning information.

Evans & Peck determined the average cost of customer connections using historic costs updated for costs of inflation. They then projected the likely number of connections and the cost of these connections, and assessed the proportion of the expenditure that was likely to be funded directly by EnergyAustralia. The result is a projection of EnergyAustralia's required expenditure to facilitate customers connecting to the network during the 2009-14 period.

Current performance

EnergyAustralia currently has 1.57 million customers (NMIs) connected to its network. Customer connection data shows a trend towards high voltage connections relative to smaller connections during the 2004-09 period – a trend that is expected to continue into the next period. This reflects an increase in high density residential developments compared with single detached dwellings as well as a larger number of high energy use customers such as data warehouses and transport facilities (eg rail) and other infrastructure (eg toll roads) connecting to the network.

EnergyAustralia is subject to obligations which require customers to pay for assets that are dedicated to their own use. In addition, where a connection drives investment in new upstream capacity, a customer must contribute to such costs where it accounts for 50 percent or greater of the new installed capacity.[33]

Results

Customer connection expenditure in the subtransmission network during the 2009-14 period is driven by a few very large customer connections which have been incorporated in the *Eastern Suburbs Area Plan* and the *Central Coast Transmission Plan*[34] . The customer connection expenditure incorporated in the Customer Connection Plan relates solely to the 17,300 new customer connections per annum that will be made to the distribution network in the 2009-14 period.

EnergyAustralia estimates that $504 million is required during the 2009-14 period to connect new customers and provide sufficient network capacity for these to meet the demand of these new customers. This forecast represents EnergyAustralia's best estimate of the impact of customer connections on the network. Ultimately, the outcome will be driven by customers, who will be influenced by economic conditions.

33 Section 6.21.4 of the Transitional Rules require capital contribution charges to be determined in accordance with IPART's capital contributions determination. This is available on IPART's website.

34 Refer section 5.3.1 for details of Area Plans.

5. Strategic capital development (continued)

EnergyAustralia is concerned that it will be held to account for this forecast, even though it is driven by the actions of third parties wanting to connect to the network. Customer connection is clearly an area of the ex-ante framework that requires refinement. EnergyAustralia has included a pass through for very large customer connections but this does not address the risk that forecast expenditure may not fully account for the costs of actual distribution customer connections during the 2009-14 period.

5.3.6 11kV Capacity Plan

EnergyAustralia's 11kV network is highly utilised and significant expenditure is required during the 2009-14 period to improve utilisation levels and to meet mandated planning standards. 11kV investment proposed for the 2009-14 period is significantly higher than the investment made in the 2004-09 period. This is driven by the fact that EnergyAustralia has largely exhausted the spare capacity that previously existed within the meshed 11kV network and is required to meet licence conditions. The network is now at a point where major additional investment in 11kV infrastructure is required to keep pace with customer demand. In addition, the DRP licence conditions introduced mandatory planning criteria for the 11kV network which must be adhered to by 2014. The criteria specifies an N-1 planning standard, which has been extrapolated to a target level of average feeder utilisation. The utilisation targets in the licence conditions are aimed at improving load restoration in the event of an outage, and thus improve reliability performance.[35]

The location and magnitude of specific 11kV work is driven by spatial demand growth which is influenced by the behaviour of individual customers. It is not possible to predict with certainty, the individual 11kV augmentation projects that will be required over more than the short term (within two years) as customers and energy consumption patterns change over time.

EnergyAustralia has used a high level model to forecast the expenditure requirements for 11kV investment over the 2009-14 period. The Distribution Network Development (DND) model is highly complex and takes account of demand growth, load density, the relative costs of investing in zone substation infrastructure compared with the costs of investing in the 11kV network, connection costs, the changing magnitude of individual customer loads, and the increasing size of distribution substations.

Attachment 5.7 "11kV Distribution Mains Capital Requirements 2009-2014" summarises the outputs of the DND model. Together they form the basis of our 11kV Capacity Plan. Based on this plan EnergyAustralia has identified two main components of capital expenditure required:

Catch-up compliance - Investment that is required to bring EnergyAustralia's current network utilisation to levels that comply with the design planning criteria based on current loads; and

Growth compliance - Investment necessary to maintain utilisation levels on the 11kV network within limits specified by the design planning criteria based upon a forecast network load growth.

EnergyAustralia's DND model provides outputs which separate these two expenditure types so that the costs of bringing the network up to the present standard can be separately identified to the costs of keeping the network at those standards into the future.

The Area Plans (discussed in Section 5.3.1) contain some 11kV network costs associated with demand capacity balance. These works are associated with specific projects in the Area Plan. To ensure no double counting, the 11kV costs incorporated in the Area Plans for growth projects have been deducted from the total expenditure figures produced by the DND model (i.e. costs of load transfers used to balance zone substation loading). In addition, the cost of forecast customer connections has also been subtracted from the model to ensure any overlap is removed.

35 The Planning Design Criteria stipulate N-1 design for urban 11kV networks, which is extrapolated in the notes to the criteria as average feeder utilization targets which are 80 percent by 2014 and 75 percent by 2019.

In contrast, the costs of 11kV works associated with zone substation replacement works are not considered in the DND model, but have been taken into account in the Area Plans. There is therefore no overlap between replacement driven 11kV works and the 11kV investment requirements recommended by the DND model.

EnergyAustralia has modelled the forecast investment requirements in the 11kV network at a regional level (i.e. CBD, Sydney, Central Coast and Hunter regions) as medium-long term forecasts of individual projects at the 11kV level are not feasible.

The forecast of growth related investment in the 11kV network uses EnergyAustralia estimates which have been reviewed by SKM (as found in Attachment 5.8)

The cost estimates incorporated in the model are based on a large sample of EnergyAustralia's historic costs. All 11kV cable laying is outsourced and is therefore market tested. SKM also considered the 11kV estimates used in the Area Plans and found them to be reasonable.

Results

The DRP licence conditions and utilisation targets specifically drive investment in 11kV network capacity during the 2009-14 period.

EnergyAustralia forecasts that significant additional capacity in the 11kV network is required during the 2009-14 period to keep pace with upstream investment and to limit utilisation of distribution feeders to 80 percent by 2014 and 75 percent by 2019 (as per the licence conditions). These utilisation targets represent a substantial improvement from current feeder utilisation levels.

The investment on capacity on the 11kV network is forecast to be $698 million over the five year period. It is made up of a catch-up compliance portion of $439 million and an ongoing compliance portion of $259 million which will continue beyond the period at this level to keep pace with underlying load growth.

Table 5.8: 11kV expenditure 2009-14 (FY09 $m real)

Catch-up compliance	439
Ongoing compliance	259
Total	**698**

5.3.7 Low Voltage Capacity Plan

EnergyAustralia engaged Evans and Peck to provide an independent assessment of the capital investment required for distribution substations and low voltage distributors during the 2009-14 planning period (Attachment 5.9)

Evans and Peck were asked to identify prudent utilisation levels for the low voltage network, and calculate the required capital to maintain these levels in the context of "organic" growth (i.e. growth associated with existing customers). The global peak demand forecast was used to determine growth on average across the network.

Evans and Peck analysed load data used as the basis of low voltage planning at EnergyAustralia. Despite some gaps in the data, Evans and Peck were able to create a robust model of the low voltage network justifying the level of expenditure they recommended. Evans and Peck identified 900 low voltage distributors and 1800 distribution substations throughout the low voltage network loaded above their assigned ratings.[36]

Evans and Peck recommended that the following maximum utilisation levels be targeted by EnergyAustralia for achievement by June 2014.

Table 5.9: Maximum utilisation criteria

Distribution Substations	
Planning Based on MDI[37] Data	100% of cyclic rating
Planning Based on Load Survey	95% of cyclic rating
Distributors	
Low voltage distributors	95% of fuse rating

The rationale for the maximum utilisation criteria is set out in the Evans and Peck report (Attachment 5.9).

36 This is a relatively small proportion of the 29,500 distribution substations and 38,611 distributors that make up EnergyAustralia's low voltage network.

37 Maximum Demand Indicator

5. Strategic capital development (continued)

Evans and Peck used EnergyAustralia's Network Regional Database, which is used to capture and manage distribution projects, to establish standard estimates for costing the plan. The range of distribution centres – pole top transformers, kiosks, distribution substations and chamber installations, and the range of locations for distribution feeders produces a variety of cost estimates for additional capacity. Evans and Peck used historic average costs for each region as the basis for its cost estimates. This methodology is explained further in their report which is attached to EnergyAustralia's Low Voltage Network Investment Plan.

Results

EnergyAustralia's proposed investment in its low voltage network investment is set out below.

Table 5.10: Low voltage network expenditure 2009-14 (FY09 $m real)

Distribution substations	148
Distribution feeders	147
Total	**295**

The program will bring utilisation on the low voltage network back to manageable levels. In addition, EnergyAustralia intends to implement a plan to improve monitoring of distribution substations which will enable utilisation of many substations to be increased from 95 percent to 100 percent. Not only will this defer capital investment, it will also reduce the costs of future load surveys. The investment program recommended by Evans and Peck (see Attachment 5.10 – Distribution substation and Low Voltage Network Capital Requirements) has been adjusted for these factors.

If this program is deferred, as it has been in the past, it will lead to customers without supply at peak and/or a reduction in network life.

5.3.8 Network support

Telecommunications replacement

During the 2004-09 period, EnergyAustralia has been rolling out modern telecommunications infrastructure with its capital program. The network which is based on optical fibre technology has largely been completed at the zone substation level. Further investment to improve connectivity and upgrade SCADA systems is required in the 2009-14 period and will be undertaken by leveraging this telecommunications platform. The IT costs associated with this connectivity project are incorporated in the Network Operational Technology Plan (Attachment 4.11).

Intelligent network

EnergyAustralia is committed to operating a world class electrical network. To do so requires a reassessment of the role that communications and new technology can play within the network. The roll-out of fibre telecommunications at the zone substation level of the network has been the first step in this process, but there are further steps required to make EnergyAustralia's network an intelligent network fit for future applications.

Advancement in data communications technology, digital substation equipment, circuit design and control techniques have provided an opportunity for widespread monitoring and remote control across the distribution network.

Presently, remote monitoring and switching is generally limited to the subtransmission network which utilises SCADA for assets at the zone level and above. A program of distribution monitoring and remote control will allow EnergyAustralia to improve the response time to outages, improve our internal processes utilising better load data and meet the challenges of a changing electricity network system in the foreseeable future. The program is driven by a need to maintain regulatory reliability compliance, provide accurate distribution asset reporting and deliver customer outcomes in terms of quality and reliability of supply.

The scope of the distribution and remote control program involves the deployment of approximately 14,000 'smart' devices, equivalent to a 48 percent penetration of EnergyAustralia's distribution substations which will initially provide widespread monitoring with a platform for remote control functionality through natural replacement of other substation components. The program will deliver the following outcomes:

- 11kV and low voltage data will be available to planners;
- reduced costs associated with manual load surveys and maximum demand indicator (MDI) readings once fully deployed;
- improved reliability reporting;
- better voltage regulation;
- improved low voltage balancing due to more information being available; and
- a reduction in fault detection and restoration times.

While improved network performance through widespread monitoring will also deliver incremental reliability improvements, EnergyAustralia needs to address specific reliability compliance problems identified through the reliability gap analysis. The distribution and remote control program will specifically target 550 network points for automation and monitoring. The reliability specific component of the program will target 232 feeders across the 11kV distribution network based on prioritised need. Deployment of these devices is forecast to improve EnergyAustralia's urban and short rural SAIDI indices by eight minutes and 34 minutes respectively.

The costs of the reliability specific component of the distribution and remote control project have been incorporated into the Reliability Investment Plan as it is a core element in achieving reliability performance in order to meet performance targets. The IT costs associated with implementing these systems are incorporated in the Network Operational Technology Plan. The remaining hardware costs are included in the Network Operational Technology Plan included as Attachment 4.11.

Advanced Metering Infrastructure

EnergyAustralia is recognised as an Australian industry leader in the development of AMI. A decision on whether there is to be a mandated roll out of AMI by DNSPs is expected to be made by the MCE in 2008. If put into place, a mandate, while supplying impetus to AMI, will require EnergyAustralia to address numerous critical questions such as, the optimum AMI technologies and the ultimate cost and benefits of AMI for the network.

It is recognised, therefore, that in order for EnergyAustralia to ensure commercially sensible outcomes from AMI regulations, we need to be:

- familiar with the latest technological developments;
- understand the business impacts of AMI; and
- test the capabilities and compatibilities of AMI with EnergyAustralia's assets and operations.

EnergyAustralia has included a modest amount of $16 million in its capital proposal to fund a series of AMI technology and meter trials in the early part of the period (2009-11). These trials are outlined in EnergyAustralia's AMI Phase II Project Scoping (Attachment 5.12).

This amount is separate to any amount EnergyAustralia would require for the roll-out of AMI meters in the next regulatory control period. EnergyAustralia raises particular concern with a regulatory change event (for pass through purposes) occurring prior to the commencement of the next regulatory control period. To cater for this EnergyAustralia has proposed to include, as a specific pass through event, an event that occurs prior to the end of this period and that has cost impacts in the next period (that have not already been factored into expenditure forecasts). Details of EnergyAustralia's "dead zone" pass through event can be found in Section 15.1.

5.3.9 Business support

EnergyAustralia has identified three categories of business support investments. These costs relate to fleet, information technology and business development, and corporate property holdings and acquisitions.

5. Strategic capital development (continued)

EnergyAustralia has used a bottom up process to forecast the capital investment requirements in these three categories. Future needs have been assessed through strategic planning to ensure that all future influences on costs have been taken into account and that the expenditure forecast reflects new strategies where appropriate.

EnergyAustralia has developed a suite of documentation in support of its capital investment required to support the business. The Network Operational Technology Plan (Attachment 4.11) and Corporate Property Strategy (Attachment 4.12) contain detailed information of the strategy, objectives, assumptions and costs of each program.

IT Strategy

EnergyAustralia requires a sophisticated network of IT systems to ensure optimal investment and planning decisions are made. EnergyAustralia also requires appropriately sophisticated reporting systems to ensure that our corporate reporting as well as system reporting requirements can be met.

EnergyAustralia has developed a comprehensive strategy for future IT needs. It covers both network support and business support IT as the line between the two is becoming increasingly blurred, particularly with new fibre technology that can be used for data capture, equipment automation and network protection.

The IT strategy is based on a comprehensive analysis of every application and system currently in use at EnergyAustralia. Each system has been assessed for current and future requirements including operating cost components.

The strategy takes account of like for like replacement for those applications that have ongoing use and scopes new initiatives that are planned for the 2009-14 period.

IT costs are expected to increase in the 2009-14 period as a result of new initiatives. The major strategic directions underpinning the proposed IT investments are:

- a new Data Centre to manage data security;
- continued support for asset investment, planning, maintenance and network control through implementation of iAMS (SAP based integrated Asset Management System); and
- extension of the EnergyAustralia work environment to mobile staff and service providers in the field.

The Data Centre is the most significant change to EnergyAustralia's IT infrastructure. It will be a critical component of EnergyAustralia's IT infrastructure for the next generation of IT systems and will improve data security in line with modern standards. EnergyAustralia proposes to invest $240 million in IT infrastructure during the 2009-14 period.

Corporate property

EnergyAustralia has undertaken a strategic review of non-system related property holdings and assessed this against future needs. The review has been largely driven by the fact that EnergyAustralia's staff numbers have increased substantially since 2004 from 3,976 to over 5,000. The provision of office accommodation has not kept pace with staff levels with the result that much of the current staff accommodation is sub-standard. The review also found that there is scope to improve the strategic fit of site holdings to current business operations and functions.

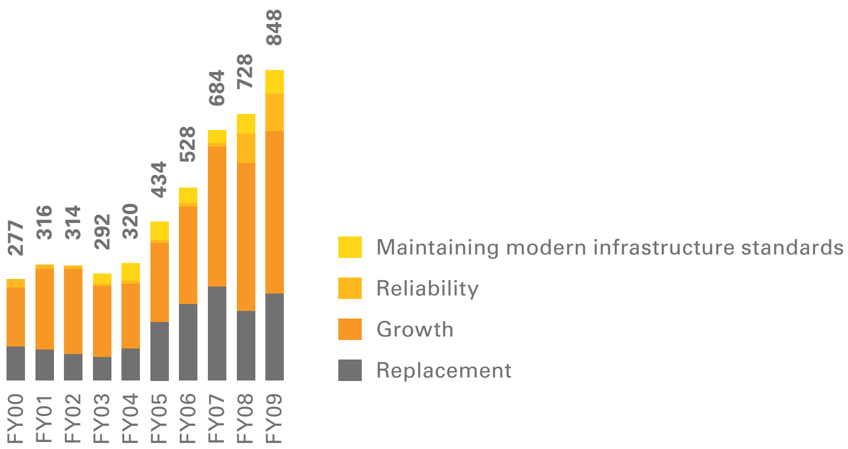
In addition, EnergyAustralia believes that it was prudent to undertake this strategic review of future property requirements against the background of the proposed sale of EnergyAustralia's retail business.

EnergyAustralia currently occupies 44 sites[38] which include eight offices, thirty depots, one warehouse, three training and testing facilities and two pole yards. The review of property holdings found that:

- there are three regions – Upper Hunter, Newcastle/Central Coast & Sydney North, Sydney South;
- five regional head quarter sites do not reflect the current structure of our service arrangements;
- some sites are under pressure from surrounding development – most notably Zetland and Noraville;
- some sites are under-utilised – most notably Dee Why and parts of West Gosford;
- some sites are overcrowded – most notably Noraville, Chatswood, Hornsby and Singleton; and
- there is significant maintenance required at some sites to meet compliance – most notably Maitland and Chatswood.

38 This does not include substation or switching station sites.

Figure 5.5: Capital expenditure by driver (FY07 $m real)



EnergyAustralia's strategic property review took place over a 12 month period and resulted in six different options that management has considered. The costs of these options were reviewed by expert quantity surveying and property feasibility experts from Rider Levett Bucknall. In addition, land valuations were sought from independent valuers, Preston Rowe Paterson.

EnergyAustralia has selected an option for property consolidation that best suits the business needs. The option is based on three zones with six regions for operational purposes.

EnergyAustralia has forecast the cost of this option to be $261 million in the 2009-14 period. This investment option is consistent with the agreed planning criteria and represents the least cost approach to consolidate existing sites, optimise site locations relative to work locations, and increase office space to cater for larger staff numbers seen during the 2004-09 period.

Fleet

Projections have been based on trends of past actual and future estimated data after allowing for staffing, operations and statutory requirements. Base line projections are adjusted to take account of the following factors:

- additional plant requirements needed to accommodate increases in staffing levels and work practices;
- apprentices moving from the training environment to operational areas;
- occupational, health and safety requirements;
- Roads and Traffic Authority provisions;
- technology changes and improvements; and
- procurement processes.

EnergyAustralia's fleet renewal policy is designed to provide a range of vehicles and plant that facilitate efficiency and productivity of EnergyAustralia's workforce and promote safe work practices.

EnergyAustralia's capital investment on fleet is forecast to be $102 million for the 2009-14 period. This program has been established using a similar methodology to that used to set the 2004-09 forecast.

5.4 Delivering the program

In the previous section, EnergyAustralia has outlined its approach to development of the capital investment plans. These capital plans form the basis for the total capital forecast for the 2009-14 period.

In this section EnergyAustralia explains how the sum of the plans is adjusted to produce an annual capital expenditure forecast which is feasible to deliver.

The issues considered at this stage in the process are:

- deliverability of the program; and
- the impact of real cost escalation.

EnergyAustralia has forecast a large program of investments for the 2009-14 period which is driven by the need to systematically replace a large number of aging network assets as well as requirements to meet mandatory licence conditions that set planning standards and reliability performance targets. The concurrence of these two drivers – replacement and licence compliance - results in a very large program of works in the 2009-14 period. However, the 2009-14 program must be viewed in light of the achievements of the current period and the investment requirements identified in the 2014-19 period. It has been forecast that the period 2014-19 will be in the order of $6.4 billion (FY09 real).

5. Strategic capital development (continued)

5.4.1 Past capital expenditure

EnergyAustralia has proven that it is capable of delivering a large capital program and that this capability can be ramped up at a rate of approximately $150-200 million per annum. Figure 5.5 shows the dramatic rise in system capital investment that has been delivered by EnergyAustralia since 2000.

5.4.2 Smoothing the capital program

EnergyAustralia has sought to match its capital program to projected levels of resources and expansion of its delivery capability.

EnergyAustralia's planners used a ramp rate for system investment of $200 million to set the target level of annual expenditure for the smoothed program.

Having established the expenditure levels that were considered to be deliverable, planners considered two mechanisms through which the capital program could be adjusted. Options to adjust the capital program include:

- project deferral using DM; and
- project deferral leading to increased operational risks.

High level analysis based on historic DM outcomes indicated that DM could be expected to defer approximately $50 million of major projects from the 2009-14 period to the next period. While this had a positive impact on the profile in terms of deliverability, it was not sufficient to provide an achievable capital investment profile. The analysis was also unable to identify which specific projects could be deferred due to the short lead times required for DM projects (i.e. DM projects being location and customer specific).[39]

EnergyAustralia's planners then reviewed all major projects to assess whether deferral could be tolerated within the program and still deliver the compliance outcomes required by the DRP licence conditions. By deferring projects at this stage, EnergyAustralia has been forced to accept greater operational risks during the period including higher load at risk at substations and greater risk of asset failure in service. This may have a global network reliability impact although it is difficult to predict the likely changes at such a high level.

In general, projects with dual drivers of asset condition and demand capacity balance were less flexible than projects driven by capacity constraints alone. The load at risk compliance deadline of 2014 for growth driven projects limited the degree of flexibility available in deferring growth driven investments. Furthermore, the integrated nature of the program, particularly the capacity and replacement programs within the Area Plans, also made deferral difficult because projects were part of an integrated sequence of required outcomes.

Having set the target expenditure levels using $200 million increments for system capital investment, only one smoothing option delivered a program that was both deliverable and would achieve licence compliance. Further deferral of capital was found to deliver non-compliant outcomes in terms of the DRP licence conditions. Project time frame variations associated with the accepted smoothing option can be found in Attachment 5.13A.

As a result of the capital smoothing analysis, EnergyAustralia's capital proposal can be seen to represent the limit to which the investment plans can be smoothed using project deferral while still achieving licence compliance and balancing operational risk.

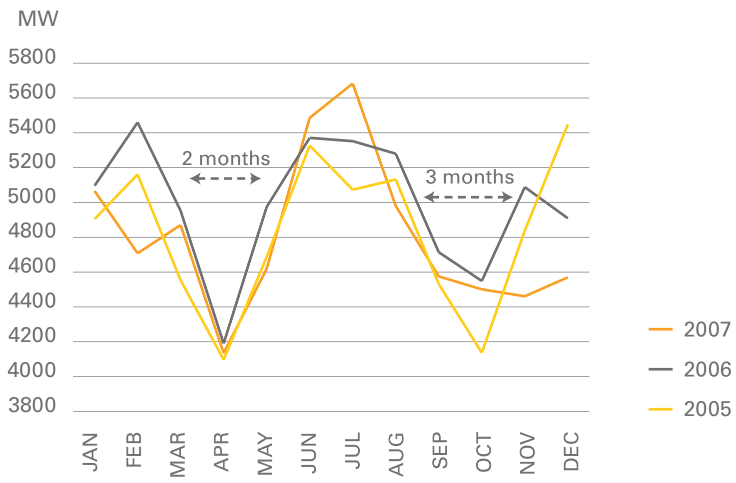
The capital smoothing process not only improved the deliverability of the capital program, it also smoothed the price outcomes for customers and the financial pressures on the business associated with a large debt financed capital program.

Despite the smoothing process, the capital program forecast for the 2009-14 period represents a significant challenge for EnergyAustralia within a resource constrained market place. Delivery of the program is a key issue which has itself been subject to a planning and development process because it is acknowledged that the opportunities for significant investment are narrowing for EnergyAustralia.

High network utilisation levels are a key feature of EnergyAustralia's network, particularly on the subtransmission network. High utilisation levels contribute to diminished windows of opportunity to conduct capital works and maintenance. Figure 5.6 demonstrates the current trend in network limitations.

39 See DM Impact on Capital Forecast – Attachment 5.13.

Figure 5.6: EnergyAustralia network peak demand by month



EnergyAustralia now faces only two blocks of two to three months each year where major equipment can be taken out for maintenance or repair while still maintaining security of supply to customers. These windows are narrowing over time and are expected to diminish further within 10 years in the absence of major investment in additional capacity. This situation is compounded by the support role EnergyAustralia's network plays for TransGrid's network. When TransGrid take either of their major Sydney supply cables (feeders 41 or 42) out of service, approximately 33 of EnergyAustralia's 132kV feeders are required to be in service to support the Sydney Inner Metropolitan load. Utilisation of the subtransmission network alone provides a compelling case for replacement of assets with larger, newer assets that will improve reliability and facilitate future works.

The 2009-14 period represents a unique opportunity to deliver network outcomes as it is clear that a continuation of growth and network utilisation trends will see circumstances become less favourable in the future. If significant investment is deferred, network reliability will be compromised and economically efficient outcomes will not be achievable. Failure to invest during the 2009-14 period may force EnergyAustralia to build an overlay network within the subtransmission network to facilitate future capital works.

EnergyAustralia intends to avoid the need to invest in an overlay network by delivering required capital outcomes in the 2009-14 period.

5.5 Delivery strategy

The capital program proposed for the 2009-14 period represents a significant increase in expenditure from previous regulatory periods. EnergyAustralia is cognisant that a large increase in required outcomes and expenditure will not occur without a suite of delivery strategies in place. EnergyAustralia has therefore developed a multi-prong approach to delivery of the 2009-14 capital program which incorporates:

1. Increased capability of EnergyAustralia staff;
2. Increase in work undertaken by ASPs;
3. Outsourcing of major projects through contracts; and
4. Strategic alliances.

EnergyAustralia staff capability: As at 30 June 2007, EnergyAustralia's field based workforce numbered approximately 3090. This represents a 37 percent increase in the numbers of internal people available to manage and deliver the capital program compared to 2004.

EnergyAustralia expects to improve the efficiency of internal resources through the use of an enhanced suite of contracting arrangements with external partners to free up internal resources, allowing EnergyAustralia to deliver more with the existing employee base.

Projects currently in place to improve efficiencies within current resource limits include standardisation of designs, streamlining of planning and approval processes and an increase in apprentice numbers.

EnergyAustralia has introduced new IT systems to help staff work more efficiently. New design software and the introduction of mobile computing are just two examples of how technology has improved the speed at which outcomes can be delivered.

ASPs undertaking contestable work: Currently, ASPs are restricted in the types of work they can undertake. Industrial negotiations underway are targeting an increase in the amount of work available to ASPs which will thereby free-up internal resources to undertake other capital works.

Outsource major projects: EnergyAustralia currently outsources all of its civil construction and cable laying to the market.

In terms of substation construction, all architectural design and construction is outsourced to the market. EnergyAustralia provides electrical specifications, installs the equipment, tests the equipment and commissions the assets.

EnergyAustralia has also utilised design and construct style contracts. This has been the case for large scale replacement feeder projects and construction of cable tunnels within the CBD.

EnergyAustralia intends to continue to outsource work on this basis in the 2009-14 period and plans to ramp up this capability through internal efficiencies and standardisation of design requirements.

5. Strategic capital development (continued)

Strategic alliance: EnergyAustralia is in the process of establishing alliance agreements with major infrastructure groups to deliver parts of the 2009-14 capital program. The alliance partnership is a mechanism whereby EnergyAustralia will outsource the end to end process of substation design, construction, equipment procurement, installation and testing to an alliance partner. EnergyAustralia resources will be expended in developing the functional specification of the projects, but the alliance partner will deliver the project.

The alliance partnership will deliver capital outcomes in parallel with EnergyAustralia's traditional outsourcing relationships. The model will help optimise internal resource capability and deliver program outcomes.

5.6 Cost estimates and escalation

The second factor that EnergyAustralia considered at the final stage in the capital planning process was the impact of cost escalation on the program during the 2009-14 period.

The Rules require the AER to consider the efficient costs of a DNSP and a realistic expectation of cost inputs required to achieve the capital expenditure objectives.

EnergyAustralia's investment plans have been costed on the basis of a build up of expected costs in constant dollars.

Projects have been estimated by EnergyAustralia's estimating experts based on standard building block estimates. The cost estimates used depend on the specific plan being costed. This is because in some cases assets are large enough to require a specific project estimate. In other cases, plans have been costed using average project costs based on historic data and external review. The costing methodology applied to each plan has been discussed under each plan, and is discussed in further detail within the plans themselves.

Cost estimates for large projects have been externally reviewed by SKM. SKM's report EnergyAustralia Substation Cost Estimate Review is included as Attachment 5.14.

History demonstrates that costs associated with our business are subject to volatility. EnergyAustralia has faced significant increases in the cost of key inputs over the 2004-09 period. This real cost escalation (cost increases above CPI) has eroded over $200 million worth of purchasing power from the regulatory allowances provided in 2004.

Figure 5.7 shows the breakdown of system capital expenditure above the 2004-09 regulatory allowance by scope and price impacts. Of the variation in expenditure of the program 60 percent was due to price, with only 40 percent due to issues of program scope.

To avoid similar value loss in the 2009-14 period, EnergyAustralia commissioned a study by CEG to determine annual real cost escalators to be applied to the forecast capital program to ensure that real purchasing power of the revenue allowance is maintained during the period.

CEG found that with the exception of labour, there were no forecasts for key electrical equipment available in the Australian market. However, CEG identified a variety of forecasts either in the form of indexes or futures markets for inputs used to produce key equipment such as oil, steel, aluminium, copper etc.

CEG's methodology to develop a forecast for the escalation of a capital expenditure program is outlined in their report (Attachment 5.15) can be summarised as follows:

Step 1 – break down the capital expenditure program into different cost categories for which there are unit cost forecasts (or for which unit cost forecasts can be derived);

Step 2 – source/derive the relevant unit cost forecasts from independent sources; and

Step 3 – calculate a weighted average escalation factor using weights derived in Step 1 and forecasts from Step 2.

Figure 5.8 shows the Step 1 breakdown of EnergyAustralia's capital program by key equipment type. It is worth noting that direct labour costs contribute more than 30 percent of costs of EnergyAustralia's capital program. In addition, there is also a large component of labour costs in other components such as civil works, cable laying and reinstatement.

Figure 5.7: System capital expenditure variance by price and scope changes 2004-09 (percent)

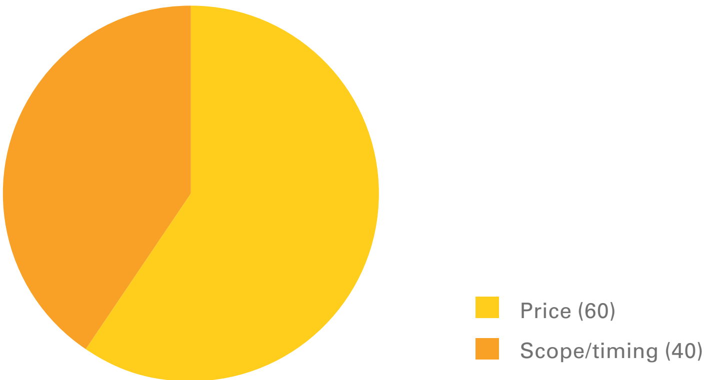
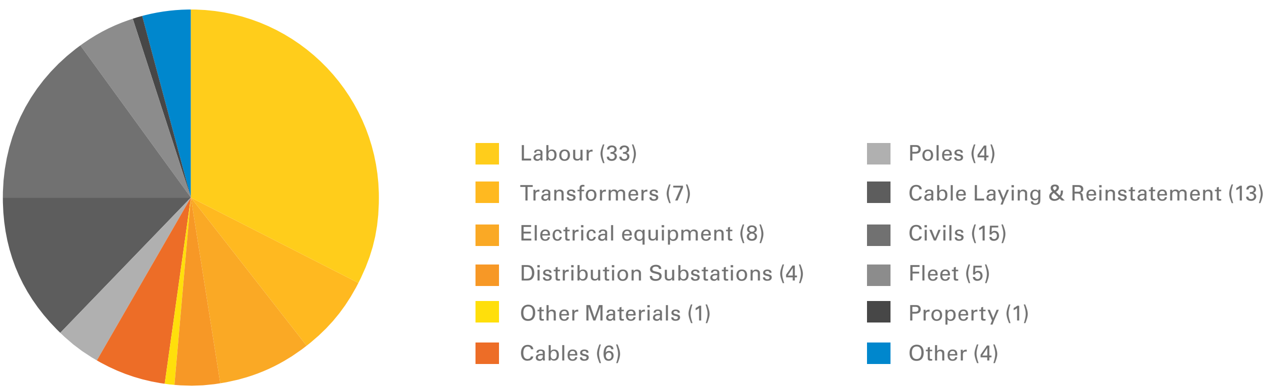


Figure 5.8: Capital program by equipment cost category 2004-09 (percent)



5. Strategic capital development (continued)

The application of CEG's recommended escalation factors to EnergyAustralia's 2009-14 capital program results in a substantial increase in costs over the period.

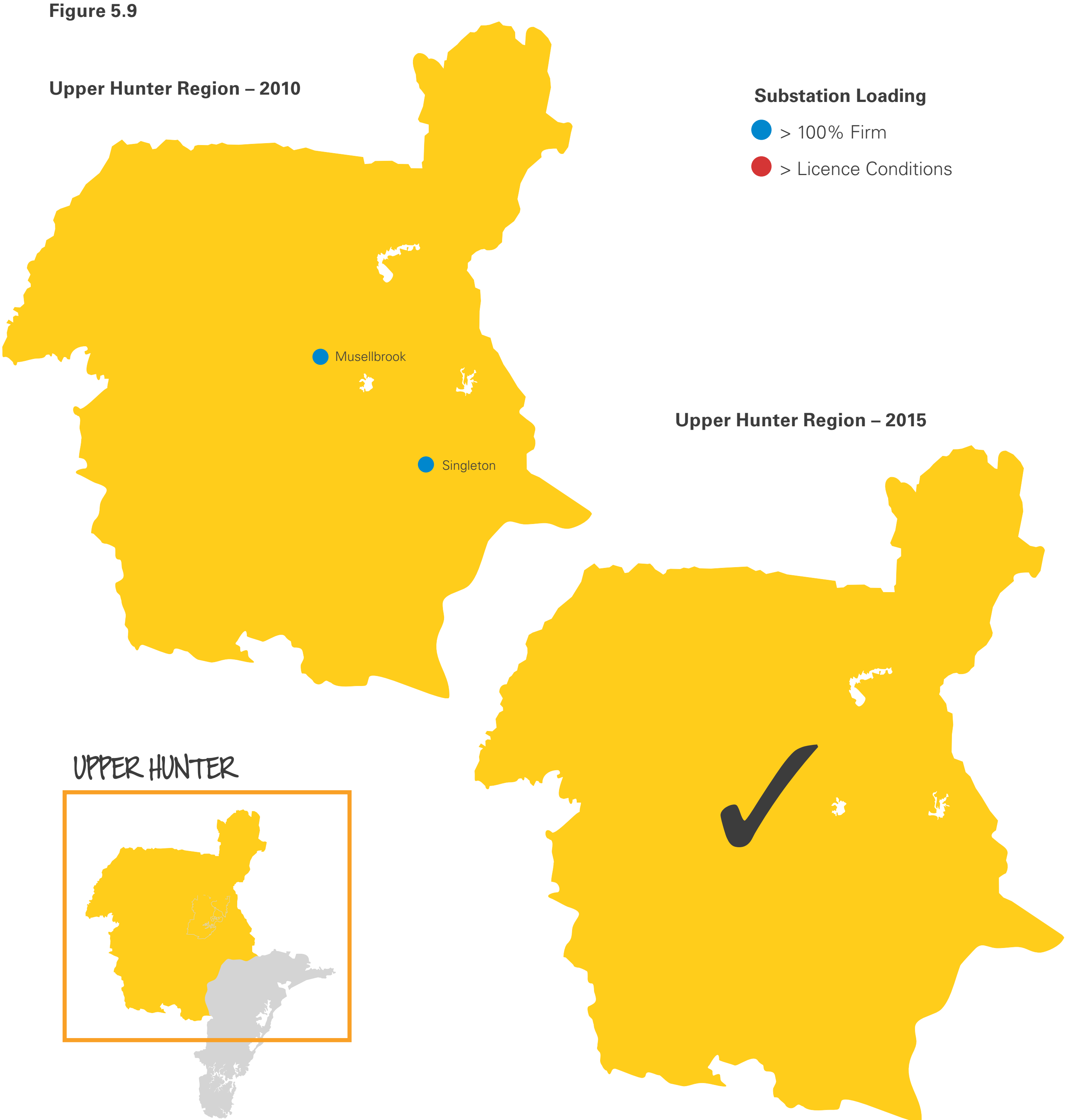
5.7 Outcomes from capital expenditure plans

Tables 5.11, 5.12 and 5.13 summarise the planned outcomes that result from the proposed capital expenditure program via the development of each plan, as described earlier in the chapter. Figure 5.9 shows the before and after investment view by region, resulting from Area Planning.

Table 5.11: Primary outcomes from capital expenditure plans by network type

Transmission and Subtransmission	
Transmission Plans	N-2 (modified) joint transmission network security
	New bulk supply point at Chullora & Tomago
Area Plans	N-2 network security in the CBD
	42 new zones commissioned
	32 zones retired
	Compliance with the planning criteria as set out in Schedule 1 of the DRP licence conditions
	Implementation of demand management projects to defer approximately $50m of capital investment
	Replacement of 1263 panels of 11kV switchgear
	Replacement of 155km of 33kV gas cable
Replacement Plan	Replacement of 141km of 132kV oil cable
	Management of key risks of supply interruption, equipment damage and worker and public safety mitigated through replacement activity
	Age profile of transmission mains, transmission substations and zone substation asset categories decreases

Figure 5.9


Upper Hunter Region – 2010
Substation Loading
> 100% Firm
> Licence Conditions
Musellbrook
Singleton
Upper Hunter Region – 2015
UPPER HUNTER

5. Strategic capital development (continued)

Figure 5.9

Lower Hunter Region – 2010

Substation Loading

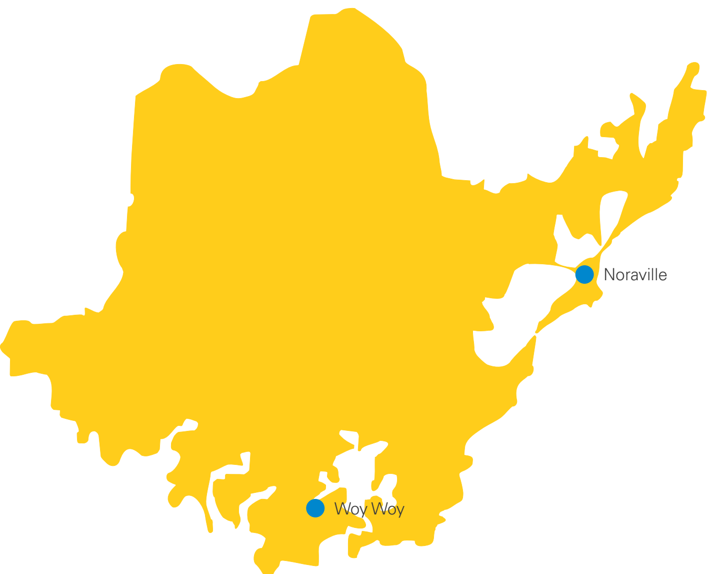
- > 100% Firm
- > Licence Conditions

Lower Hunter Region – 2015

Figure 5.9

Central Coast Region – 2010

Central Coast Region – 2015



Substation Loading

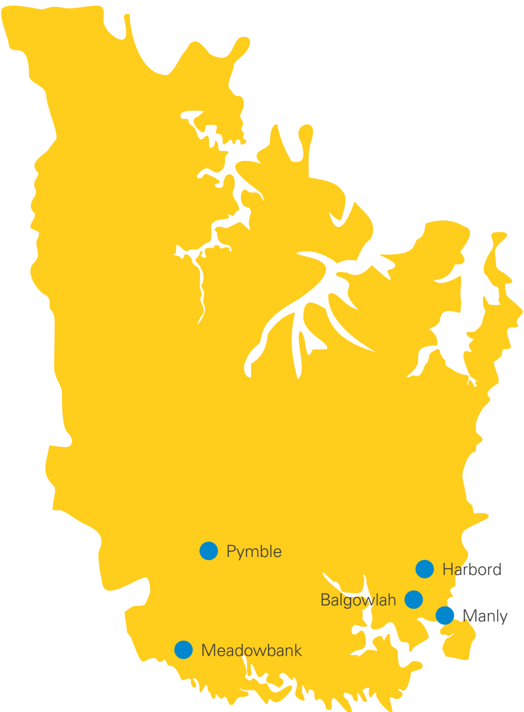
> 100% Firm

> Licence Conditions

5. Strategic capital development (continued)

Figure 5.9

Sydney North Region – 2010

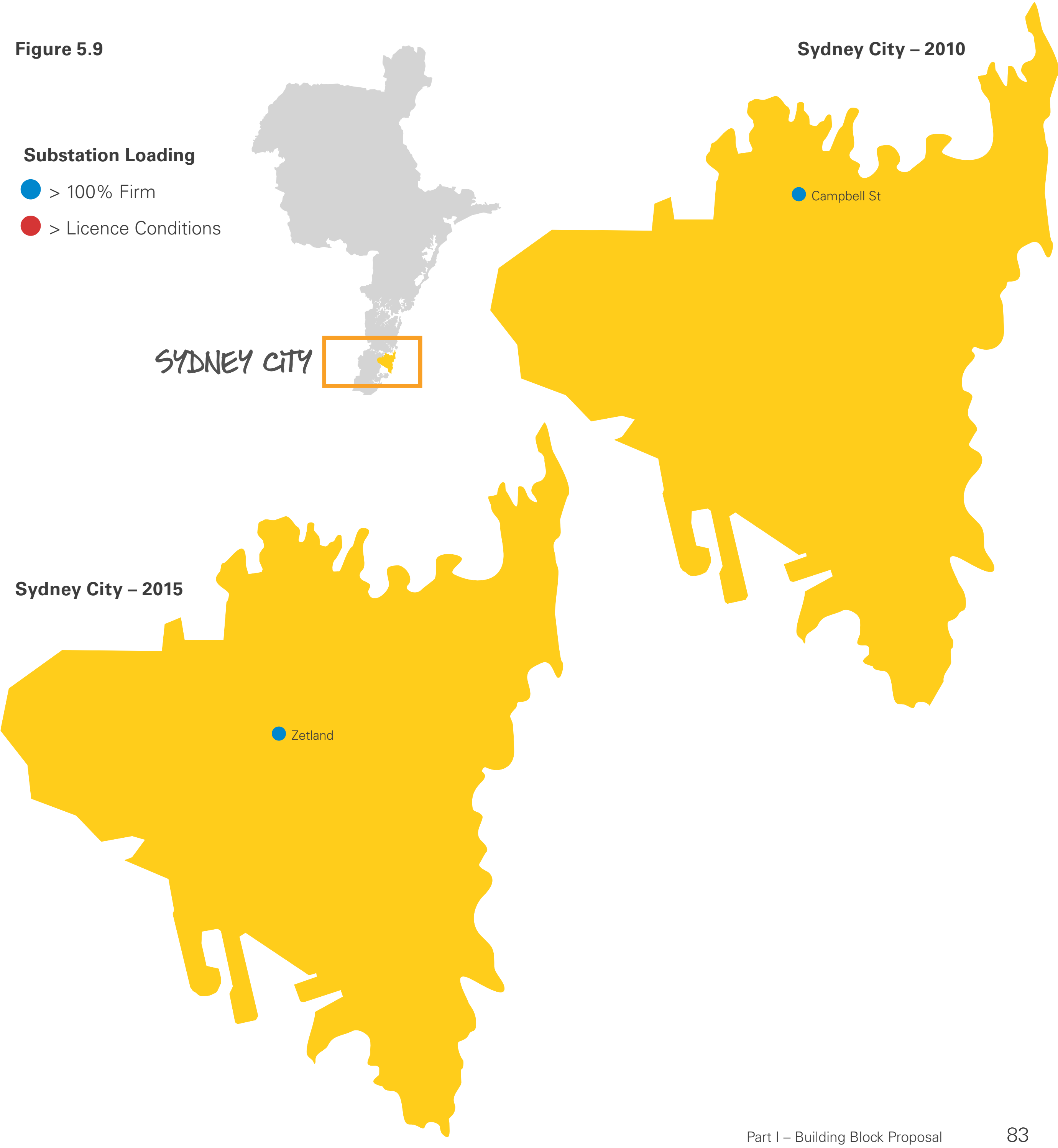


Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney North Region – 2015

Figure 5.9


Substation Loading
> 100% Firm
> Licence Conditions
SYDNEY CITY
Sydney City – 2010
Campbell St
Sydney City – 2015
Zetland

5. Strategic capital development (continued)

Figure 5.9

Sydney South Region – 2010

Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney South Region – 2015

Table 5.12: Distribution outcomes from capital expenditure plans by the network type

Distribution	
11kV Capacity Plan	Average utilisation for 11kV feeders drops to 80 percent by 2014
Low Voltage Capacity Plan	Utilisation for low voltage distributors is <100 percent of equipment rating Utilisation for low voltage substations is <100 percent of equipment rating
Duty of Care Plan	Compliance with Environmental and OH&S legislation and obligations Compliance with security requirements for key pieces of infrastructure
Reliability Investment Plan	Compliance with mandatory performance targets set out in Schedules 2 & 3 of the DRP licence conditions Delivery of satisfactory network performance to all customers through black spot program
Replacement Plan	Age profile of distribution substation and distribution mains asset categories continues to increase
Customer Connection Plan	An average of 17,300 customers connected to the network
System IT Strategy	Implementation of the intelligent network to faciliate network operations and planning functions SCADA system replacement

Table 5.13: Business outcomes from capital expenditure plans

Business Outcome	
IT Strategy	Implementation of Data Centre to provide data security and integration to support business and network operations
	Implementation of iAMS to facilitate business and network opertions
Corporate Property Strategy	Acquisition and disposal of corporate property holdings to deliver optimal office and depot locations Provision of office accommodation for all employees to corporate standard
Fleet Strategy	Fleet of vehicles and equipment sufficient to deliver large capital program and maintain the network

5. Strategic capital development (continued)

5.8 Conclusion

This chapter provides a description of the prudent processes which EnergyAustralia applies to developing its capital expenditure forecasts. The diverse nature of elements of the business and their equally diverse influences on performance require a multifaceted planning process, with separate plans to reflect the different network types and drivers of investment. Importantly, to the maximum extent possible, synergies between these plans are used to minimise overall expenditure.

The AER must be satisfied that EnergyAustralia's capital expenditure forecasts reasonably reflect the capital expenditure criteria. This means that the forecasts must reasonably reflect the efficient costs of a prudent operator in EnergyAustralia's circumstances in meeting the capital expenditure objectives.

The planning processes used by EnergyAustralia represent a comprehensive and robust analysis of network needs by driver at each level of the network and for the business.

EnergyAustralia's forecast capital expenditure for the 2004-09 regulatory control period is $8.66 billion (FY09 real).

The magnitude of this proposed capital program is greater than EnergyAustralia has carried out to date. Chapter 6 goes on to outline the prudent considerations given to delivering this program at a global level, including the consideration of alternative expenditure profiles and delivery strategies.

6. Aligning capital expenditure forecasts with Rule requirements

The purpose of this chapter is to:

- explain how EnergyAustralia has considered Transitional Rule 6.5.7 in our processes and our forecasts; and
- provide further information to enable the AER to satisfy itself that the forecast capital expenditure EnergyAustralia considers is required to achieve the capital expenditure objectives, reasonably reflects the capital expenditure criteria outlined in the Rules.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.5.7)

A Building Block Proposal must include the total forecast capital expenditure for the relevant regulatory control period which EnergyAustralia considers is required in order to achieve the capital expenditure objectives.

The AER must accept EnergyAustralia's forecast of required capital expenditure that is included in a Building Block Proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects (the capital expenditure criteria):

(1) the efficient costs of achieving the capital expenditure objectives; and

(2) the costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In deciding whether or not the AER is satisfied, the AER must have regard to the following capital expenditure factors:

(1) the information included in or accompanying the Building Block proposal;

(2) submissions received in the course of consulting on the Building Block Proposal;

(3) analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period;

(5) EnergyAustralia's actual and expected capital expenditure during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent EnergyAustralia's forecast of required capital expenditure is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent EnergyAustralia has considered, and made provision for, efficient non-network alternatives.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

6.1 Developing capital expenditure forecasts in the absence of rule requirements

EnergyAustralia's strategic capital development process was initiated prior to the new rule requirements, which require Distribution Service Providers to consider how:

- expenditure meets predefined objectives;
- expenditure reflects efficient costs;
- expenditure reflects costs of a prudent operator; and
- demand forecasts and cost inputs underlying forecasts are a reasonable expectation of what is required.

Nevertheless, EnergyAustralia's planning and forecasting approach has been fundamentally founded in meeting service delivery outcomes, using industry leading capital planning processes and the principles in the existing regulatory framework regarding the evaluation of capital projects. Where appropriate, EnergyAustralia's forecasts were considered against alternative approaches, and independently assessed or externally benchmarked.

While our case for prudent and efficient capital forecasts to meet service outcomes is clearly substantiated in the previous three chapters, EnergyAustralia considers it necessary to review and ensure alignment of our capital expenditure requirements in light of the new provisions under the national framework.

The purpose of this chapter is to focus specifically on the AER's considerations relevant to making a decision under 6.12.1(4) of the Rules. In particular, this chapter:

- reconciles our forecasts against the achievement of the capital expenditure objectives;
- looks specifically at the AER considerations in assessing our capital expenditure forecasts; and
- uses previous AER considerations and independent expert advice to ensure that there is sufficient information in our proposal to satisfy the AER that our expenditure forecasts reflect the capital expenditure criteria.

6.2 Forecasts that meet the capital expenditure objectives

To achieve the capital expenditure objectives, EnergyAustralia's network needs to exhibit the following practical characteristics:

- sufficient capacity to meet the expected demand or the ability and flexibility to manage demand through alternate mechanisms during the period;
- the ability to connect customers to the network and supply those customers;
- compliance with all regulatory obligations, including all obligations that fall outside the NEL's definition of a regulatory obligation or requirement;
- provision of Standard Control Services of appropriate quality, reliability and security;
- sufficient maintenance to ensure that the network itself is reliable, safe to operate, safe to work around and is a secure network; and
- sufficient systems and structures in place to deliver these outcomes.

In order to achieve the practical outcomes that the capital expenditure objectives describe, EnergyAustralia has applied a set of investment criteria, that when met, trigger investments that deliver, or contribute to one of these outcomes.

EnergyAustralia's capital forecast has been developed by identifying drivers and quantifying the impact of those drivers when they meet the investment criteria. By investing whenever the criteria is met, EnergyAustralia can deliver an outcome that achieves the capital expenditure objectives and delivers the practical outcomes listed above.

EnergyAustralia has demonstrated the practical outcomes of its proposed expenditure and the link to the objectives in Chapter 5. A summary of the links between plans, expenditure and objectives is shown in Table 6.1.

Table 6.1: Linking plans and capital expenditure to capital expenditure objectives (FY09 $m real)

Plans	Trans. Area Plans	Subtrans. Area Plans	Replacement Plan	Reliability Investment Plan	Duty of Care Plan	Customer Connection Plan	11kV Plan	Low Voltage	Network Comm. & Tech. Plan & Other support
	●●●●●	●●●●●	●	●	●	●	●	●	●
Meet & manage demand (Obj. 1)	✔	✔				✔	✔	✔	✔
Comply with regulatory obligations (Obj. 2)	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintain supply of services (Obj. 3)			✔	✔	✔		✔	✔	✔
Maintain distribution system (Obj. 4)	✔	✔	✔	✔	✔				✔
Total	443	3,506	1,828	79	285	504	698	295	1,020

Key for drivers					
Peak demand growth ●	Replacement/asset condition ●	Meeting modern infrastructure standards ●	Reliability ●	Customer connections ●	Operational efficiency ●

6.3 Satisfying the capital expenditure criteria

Transitional Rule 6.12.1(3) requires the AER to make a constituent decision to either:

(i) accept the total of the forecast capital expenditure for the regulatory control period that is included in the current Building Block Proposal; or

(ii) not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current Building Block Proposal.

If the AER does not accept the total forecast, the AER must set out its reasons for that decision and an estimate of the total of EnergyAustralia's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

The AER therefore, acting in accordance with Transitional Rule 6.5.7, must decide whether it is satisfied that EnergyAustralia's forecast of capital expenditure reasonably reflects the capital expenditure criteria. If it is not satisfied, the AER must determine and substitute an estimate which it is satisfied does reasonably reflect the capital expenditure criteria (referred to at the beginning of the chapter).

In deciding whether or not it is satisfied the AER must have regard to the *capital expenditure factors* (referred to at the beginning of the chapter).

In order to provide sufficient information for the AER to make its decision in accordance with Transitional Rule 6.12.1(3) EnergyAustralia has set out in this chapter to explain how it has taken account of these factors in preparing the forecast.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

Concepts of prudency and efficiency are not new to utility regulation, however, the precise application of these concepts within a codified rules framework and within the overall context of a new national framework for economic regulation has not been tested.

In particular the new framework requires concepts of prudency and efficiency to be considered:

- in the context of forecast capital expenditure (whereas in the past these concepts have generally been applied to *ex post* consideration);
- in the context of the capital expenditure criteria which requires the AER to look at the "efficient costs" and the costs of a prudent operator in the circumstances of EnergyAustralia;
- in the context of the capital expenditure objectives outlined in Transitional Rule 6.5.7(a);
- in the context of the capital expenditure factors outlined in Transitional Rule 6.5.7(e); and
- in the context that the AER must make a decision whether it is satisfied or not satisfied that the forecasts reasonably reflect the criteria.

EnergyAustralia therefore sought guidance from past AER determinations and from the Rules regarding the application of the terms "prudent" and "efficient".

EnergyAustralia also sought an independent opinion from NERA Consulting as to how, from an economic perspective, the Regulatory Proposal should be approached and structured in the context of the above considerations.

EnergyAustralia has reviewed the process used to forecast its capital expenditure to identify whether it reasonably reflects the criteria and the factors in light of NERA's advice. NERA's advice and EnergyAustralia's review of its process is summarised against the factors and the criteria in the following sections.

NERA's report is included as part of this Regulatory Proposal (Attachment 6.1). Its advice included considerations which a Regulatory Proposal should address in order to satisfy the AER that the processes followed and reasoning applied, will lead to prudent and efficient outcomes.

These considerations are:

- a clear link between the forecast expenditure and the expenditure objectives;
- clear consideration of key uncertainties, including potential adverse consequences;
- the appropriateness of the approach to forecasting for different expenditure categories, given the nature of the expenditure;
- recognition of the specific circumstances of the DNSP that could be expected to affect expenditure;
- consideration of the efficiency of the total forecast expenditure, distinct from the efficiency of each individual component of that expenditure;
- consideration of alternative options for meeting the expenditure objectives, including potential trade-offs between capital and operating expenditure and network and non-network expenditure; and
- consideration of the efficiency of expenditure over the longer term, beyond the five year regulatory period.

Addressing considerations of prudent and efficient processes can be complemented by analysis of key indicators that focus on the level of expenditure required to achieve the expenditure objectives.

This involves a consideration of partial indicators in the context of a DNSP's circumstances which include:

- benchmarking against the costs of other DNSPs, having adjusted for differences in the relevant circumstances;
- comparison between forecast expenditure and past expenditure, including the extent to which past expenditure may be taken to be efficient due to the incentives present in the regulatory regime;
- application of the regulatory test to any aspect of the capital augmentation program; and
- the extent to which activities have been outsourced to non-related third parties, via contestably awarded contracts (eg, construction contracts for new substations).

EnergyAustralia has applied these considerations to its own forecast process to confirm that it contains the hallmarks of an efficient and prudent process that, when combined with well targeted benchmarking, will indicate that its forecasts reflect the criteria.

6.4 Having regard to capital expenditure factors

Transitional Rule 6.5.7(e) sets out 10 factors that the AER must have regard to when making a decision as to whether it is satisfied that the forecasts reasonably reflect the capital expenditure criteria.

Some of these factors are not relevant to the preparation of the Regulatory Proposal. Factors 2 and 3 will be considered by the AER following the submission of our proposal. Factor 8 refers to the incentives inherent in a Service Target Performance Incentive Scheme in which financial incentives are not to apply in the next period.

Capital Expenditure factors specifically considered in the demonstration of prudent and efficient processes include:

- 6.5.7(e)(6) relevant prices of capital and operating inputs;
- 6.5.7(e)(7) substitution possibilities between operating and capital expenditure; and
- 6.5.7(10) the extent to which EnergyAustralia has considered and made provision for efficient non-network alternatives.

Capital Expenditure factors specifically considered in forecasting efficient levels of expenditure include:

- 6.5.7(e)(4) benchmark capital expenditure that would be incurred by an efficient DNSP over the period;
- 6.5.7(e)(5) EnergyAustralia's actual and expected capital expenditure during any preceding periods; and
- 6.5.7(e)(9) the extent the forecast of required capital expenditure is referable to arrangements with a person other than EnergyAustralia that, in the opinion of the AER do not reflect arms length terms.

EnergyAustralia, having regard to the capital expenditure factors outlined in Rule 6.5.7, demonstrates that its forecasts reflect the capital expenditure criteria in three ways:

- Our planning, forecasting and decision making processes, which are geared to reflect our circumstances, are grounded in prudent consideration and motivated towards delivering efficient outcomes – see Section 6.5;
- Our processes lead to prudent and efficient outcomes through observation of the indicators of an efficient level of expenditure – see Section 6.6; and
- Demonstration that our demand forecasts and cost inputs reflect a realistic expectation of future circumstances – see Section 6.7.

6.5 Reflecting the capital expenditure criteria through process

The focus of Transitional Rule 6.5.7 is on forecasts of expenditure, which have no direct or absolute measure of efficiency either at the time the forecasts are made or after the event. For this purpose therefore, efficiency must be measured in a relative (not absolute) sense. This appears to be consistent with:

- the presence of an incentive framework to encourage efficiency improvement; and
- the revenue and pricing principles in the NEL.

Because there are no directly observable measures of absolute efficiency, the Rules cater for:

- a consideration of efficiency in a broader context of the capital expenditure criteria; and
- a series of indictors which can be directly observable and which are reflective of efficiency.

The second of these criteria "the costs of a prudent operator in the circumstances of the DNSP" while not an economic concept, is useful in the consideration of efficiency in this context.

NERA's advice indicates that both the business and the regulator can gain a level of satisfaction that the expenditure forecasts reasonably reflect the capital expenditure criteria by demonstrating that the processes followed in establishing the forecasts reflect those of a prudent operator in the circumstances.

The reference to a "prudent operator" in the expenditure criteria provides some guidance as to how efficiency may be identified in practice. We have already identified that a key aspect of prudence is the process followed by the DNSP. An important dimension of the prudence of a process is the degree to which it is motivated by (or reflects) improvements in efficiency. A process that is motivated by efficiency will in turn ensure that the DNSP moves closer to the efficiency frontier, even though that frontier will itself be moving.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

For example, a prudent process is likely to be one that considers alternative options for undertaking an augmentation. The motivation behind that process is to select the least cost option for that augmentation (all other factors being equal), ie, it is an efficient option. A prudent process can therefore be expected to result in the DNSP moving towards maximum cost efficiency, even as that efficiency benchmark is itself moving. In other words, an assessment of prudence, ie, satisfaction of the criterion in Transitional Rule 6.5.7(c)(2), can be expected to also lead over time to satisfaction of the criterion in Transitional Rule 6.5.7(c)(1).

6.5.1 Consideration of key uncertainties including potential adverse consequences

EnergyAustralia conducts risk assessments in relation to asset replacement decisions. This is particularly relevant in the areas of asset replacement and ensuring compliant infrastructure.

EnergyAustralia's risk assessment process considers the probability of asset failure and the consequence of its failure in service. The models used are based on the Australian Standard for Risk Assessment – AS/NZS 4360 Risk Management and AS/NZS 3931 Risk Analysis of Technological Systems – Application Guide.

EnergyAustralia is confident that its assessment of risk represents that of a prudent operator in the current circumstances. The risk assessments are designed to avoid failures in service and the subsequent higher costs that result from emergency repair and replacement works.

6.5.2 Forecasting for different expenditure categories

EnergyAustralia's forecasting approach for different expenditure categories reflects the trade-off of the costs and benefits of different forecasting approaches.

Where projects are large in number and small in scope, assumptions of project cost have been based on an average of a large sample of historic observations. This approach is appropriate where the cost of providing individual project estimates outweighs the benefit of doing so.

In contrast, where projects are large and discreet, EnergyAustralia has estimated the projects individually following an assessment of design feasibility and likely drivers of costs such as site factors and congestion.

EnergyAustralia's strategic investment planning process has used a bottom up approach to planning, to ensure all network needs are met. EnergyAustralia identifies network requirements by comparing existing performance to required network performance based on our obligations.

The planning process uses gap analysis to establish the needs, and a prioritisation process based on obligations and risk is used to rank these requirements. Planning solutions have been developed to ensure that synergies between drivers are maximised and that the resulting investment plan meets the capital expenditure objectives for the minimum cost.

Investment plans are based on a comprehensive suite of asset condition, network reliability and demand forecast information. Projects are subject to technical design review to ensure they are feasible, and represent optimal solutions.

EnergyAustralia has identified areas of potential overlap between investment plans and adjusted the plans where there was potential for duplicated outcomes. This analysis ensures that the suite of investment plans represents the minimum level of investment required to achieve the objectives.

EnergyAustralia utilises standard costing methodologies to cost investment plans. Standard greenfield estimates have been subject to external review. Where appropriate, additional allowances have been made for non-standard equipment or where projects require brownfield construction methods. These allowances have also been the subject of external review.

EnergyAustralia has utilised methodology developed by CEG to establish a suite of cost escalators which underpin EnergyAustralia's forecast capital program. The methodology has produced a robust set of cost escalators that reflect a reasonable forecast of the real cost changes faced by distribution network providers.

6.5.3 Recognition of a DNSP's circumstances

EnergyAustralia owns one of the oldest networks in Australia. It services the largest load centre in Australia, which is characterised by high population density and congestion. These circumstances lead to the extensive use of underground assets. Such assets are more expensive to install than overhead assets and are generally very reliable. However, when they do deteriorate or ultimately fail, they are very difficult to maintain and costly to repair.

EnergyAustralia has the largest amount of underground subtransmission feeders within its network of any distributor or transmission provider in Australia. This means that EnergyAustralia's network is unique and faces unique challenges in terms of maintenance, construction and asset replacement.

EnergyAustralia also faces pressures from the high costs of operating in a densely populated environment including the high cost of land and easements, high cost of labour, high cost of accessing assets (traffic management, overnight work) and high cost of construction in a resource constrained market.

EnergyAustralia has a relatively more expensive cost base than its peers. However, this is driven by factors outside the control of the business.

Both SAHA (in Attachment 6.2) and SKM (in Attachment 5.14) noted the unique nature of EnergyAustralia's assets. Their studies found that EnergyAustralia's costs were reasonable, when EnergyAustralia's specific circumstances were taken into accounted.

6.5.4 Consideration of the efficiency of the total forecast expenditure

EnergyAustralia notes that the total capital expenditure proposed for the 2009-14 is significant both in terms of historic expenditure and in terms of Australian peers. EnergyAustralia has therefore applied specific consideration to the total level of expenditure proposed to ensure that it represents a prudent and efficient profile.

EnergyAustralia considered the total forecast including the timing of the forecast over the period. Section 5.4.2 outlines how EnergyAustralia has adjusted the forecast to take account of feasibility and delivery constraints, particularly during the early years of the 2009-14 period. Section 5.5 outlines EnergyAustralia's strategy to deliver the capital program over the period. The strategy utilises a variety of different mechanisms including increased out-sourcing, increased competition for smaller works, as well as the use of multiple strategic alliances to deliver the program.

Consideration has also been given to deferral of the total capital expenditure program within and beyond the regulatory control period. These alternatives have been assessed through:

- analysis that calculates the increased cost of direct maintenance that results if replacement works are deferred;
- examination of costs and risks associated with deferral of approximately $300 million worth of replacement into the next regulatory control period as well as deferring approximately $250 million within the period. Any further deferral of expenditure was found to jeopardise compliance and unacceptably increase network risks; and
- examination of the consequences of delayed investment that will inevitably result in higher overall capital costs due to the construction of an overlay network. The opportunity for incremental investment will be lost unless substantial subtransmission capacity is added to the system within the period.

EnergyAustralia's total capital program reflects these considerations. The total capital expenditure proposed represents what EnergyAustralia considers to be the optimal mix of prioritisation and deferral of works that, as a whole, enables EnergyAustralia to achieve its objectives in this period and beyond.

6.5.5 Consideration of alternative options

EnergyAustralia has demonstrated in its proposal how it has considered alternative ways of meeting the capital expenditure objectives including reference to the following capital expenditure factors:

- relative prices of operating and capital inputs (Factor 6);
- substitution possibilities between operating and capital expenditure (Factor 7); and
- the extent to which non-network alternatives have been considered and provided for (Factor 10).

Consideration of alternative options within the capital planning process

EnergyAustralia has demonstrated that its approach to developing its capital expenditure forecasts has been built using a multifaceted planning methodology and applied with the primary motivation of being able to demonstrate both prudence and efficiency.

Area plans: EnergyAustralia has adopted a structure of Area Plans for its transmission and subtransmission network to demonstrate its prudent approach to long term planning and its goal of achieving maximum outcomes for its transmission and subtransmission assets.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

EnergyAustralia believes that a prudent approach for strategic assets:

- requires a long term (15 year) time frame to understand the consequences of different investment scenarios; and
- requires assessment of multiple drivers at the same time to ensure the most optimal investment strategies are being adopted.

The area planning process has incorporated the consideration of multiple strategies at a granular level, with the aim of identifying the strategy that delivers the best outcome for the lowest cost.

The Area Plans represent almost 45 per cent of the investment required in the 2009-14 regulatory control period and outline substantive investments for the two periods following.

Replacement plan: EnergyAustralia has outlined its plan for the systematic replacement of assets in poor condition over a 15 year period (or less where the population of assets can be removed in a shorter time period). The Replacement Plan embodies the expert assessment and prioritisation of different network risks by professional asset managers using sophisticated tools that assess both probability and consequence of failure at an individual level and at a population wide level.

EnergyAustralia has considered the ongoing impact of the Replacement Plan on the likelihood of future asset failures. Each replacement program is assumed to target the worst performing assets first and is expected to result in a decrease in the failure of those assets whilst in service as the program progresses within each asset type.[40]

11kV plan: EnergyAustralia has identified in its 11kV Plan that its distribution network does not meet required standards of network security and that significant "catch-up" investment is required if EnergyAustralia is to avoid being non-compliant with the mandatory Design Planning Criteria.

Given the breadth and size of the distribution network, EnergyAustralia has developed models that optimise investment outcomes over the period, rather than rely on inductive assumptions of capital investment requirements. The cost of the program has been estimated using statistical analysis of a large sample of historic costs that reflect the breadth of investment options and costs that will be used to add substantial capacity to the 11kV network over the 2009-14 period.

Customer connections: EnergyAustralia has sought the assistance of external engineering experts Evans and Peck[41] to determine the forward projections of expenditure on customer connections. In addition, the costs of typical customer connection investments have been reviewed by other external engineers (SKM) to ensure that the forecast is a true reflection of current costs.

Low voltage capacity: EnergyAustralia has also sought external advice to determine future investment requirements in the low voltage network. Evans and Peck were asked to assist with this analysis and determine appropriate utilisation levels for network elements in the absence of explicit planning criteria. The costs were derived from the statistical analysis of historic costs and escalated on the basis of external advice to ensure they reflect the actual cost of delivering additional capacity in the low voltage network.

Throughout the planning process, EnergyAustralia has applied a variety of approaches to forecasting requirements and has considered a variety of strategies to deliver the outcomes required. The capital planning process embodies thorough consideration of alternate options.

Relative prices of operating and capital inputs and substitution possibilities (capital expenditure Factors 6 and 7)

EnergyAustralia has built models to integrate the capital and operating programs and calculate the annual impact of capital works. The most significant interaction occurs in relation to replacement and its impact on maintenance expenditure.

Capital works have two impacts on maintenance costs:

- maintenance costs rise as the asset base grows and the number of units of equipment to be maintained increases; and
- maintenance costs fall as old and poorly performing equipment is replaced with newer equipment that is less costly to maintain.

EnergyAustralia has calculated the impact of all its Area Plans and its Replacement Plan on its maintenance costs. The Replacement Plan has the largest influence on maintenance costs as shown by Figure 6.3.

40 This statement assumes that the replacement program is accepted as proposed. Cuts to replacement will lead to funding being directed to reactive replacement at higher costs rather than proactive replacement.

41 See Attachment 5.6

Figure 6.3: Impact of investment plans on maintenance ($m)

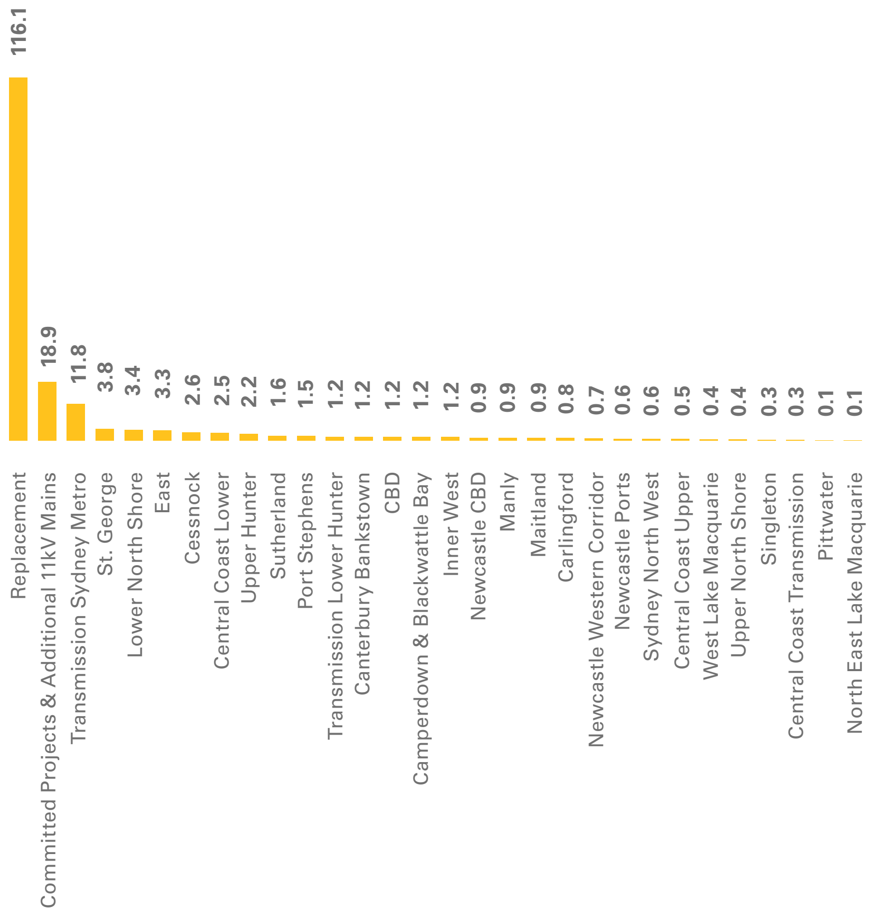
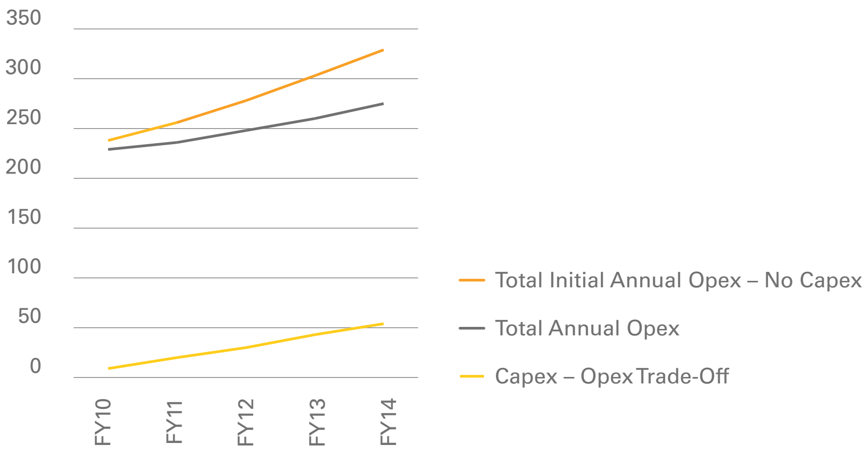


Figure 6.4: Annual maintanance impact (FY09 $m real)



6. Aligning capital expenditure forecasts with Rule requirements (continued)

EnergyAustralia has calculated the annual maintenance impact of failing to undertake the proposed replacement programs. This is shown in Figure 6.4.

The annual increase in maintenance costs as a result of failing to implement the replacement program has been calculated to be $9 million per annum in 2009-10 rising to $54 million per annum by 2013-14. This escalating annual cost of failing to replace poorly performing assets demonstrates that EnergyAustralia can no longer afford to substitute maintenance for capital works.

This result is supported by SAHA International in their benchmarking report for EnergyAustralia, which states that EnergyAustralia's operating costs are likely to increase in the future as a result of aged and poorly performing assets. Furthermore, SAHA assert that the only feasible manner in which EnergyAustralia can reduce its maintenance cost, whilst maintaining performance outcomes, would be to engage in systematic replacement of poorly performing assets.

Consideration and provision for non-network alternatives (capital expenditure Factor 10)

EnergyAustralia notes that it has long been recognised as an industry leader in respect of demand management and has an extensive track record of implementing demand management projects that defer capital investment and influence energy consumption behaviour.

In developing forecasts EnergyAustralia has not forecast the impact of demand management on individual projects. This is because demand management projects are locational and timing specific and it is impossible to reasonably predict the take-up of initiatives that could result in capital deferral at an individual project level two to seven years in advance.

Instead, EnergyAustralia has made provision for the costs and benefits of demand management based on results derived during the 2003-07 period at a global program level. The implementation of DM projects throughout the period is projected to result in approximately $50 million being deferred from the 2009-14 period into the 2014-19 period. These calculations are found in Attachment 5.13 *DM impact on capital forecasts*.

Demand forecasts have also been adjusted to take into account EnergyAustralia's initiatives in tariff based demand management. This is discussed further at section 6.7.2.

6.5.6 Consideration of the medium and long term forecast efficiency

EnergyAustralia's decisions regarding the overall level of capital expenditure in 2009-14 took into careful consideration the forecast expenditure profile in 2014-19. The profile of expenditure has been adjusted for capital smoothing, but shows a significant ramp in expenditure during the 2009-14 period, which is still double the current requirements in the 2014-19 period.

The Area Plans, Replacement Plan and 11kV Capacity Plan provide detailed information about the network's investment requirements 15-20 years into the future. Planning within this timeframe allows investment choices in the short term to be compatible with those required to meet longer term outcomes. This avoids a piecemeal approach to network development which leads to inefficient outcomes.

Furthermore, the detailed nature of the plans ensures that variations to plans in the future can be identified and reconciled back to the plans on which the capital investment strategy for 2009-14 is based.

6.6 Reflecting capital expenditure criteria through observing indicators of an efficient level of expenditure

Addressing considerations of prudent and efficient processes (outlined in the previous section) can be complemented by the analysis of key indicators of the level of expenditure required to achieve the expenditure objectives.

EnergyAustralia has applied these considerations to its own forecast process to confirm that its process contains the hallmarks of an efficient and prudent process that, when combined with well targeted benchmarking, will indicate that the forecast of demand and cost inputs is relatively efficient.

EnergyAustralia believes that partial indicators are inherently limited in that results can be manipulated for a particular outcome through the selection of the measurements to be compared via simple analysis of ratios. However, EnergyAustralia notes that partial indicators are widely used and therefore should be considered as part of this analysis.

6.6.1 Benchmarking of DNSP costs (capital expenditure Factor 4);

Benchmarking forecast costs is included as a factor (Clause 6.5.7(e) (4)) that the AER must consider when assessing EnergyAustralia's capital forecast.

EnergyAustralia engaged two consultants to assist with benchmarking its capital input costs:

- SKM, for the reasonableness of greenfield estimates; and
- SAHA, for asset management strategies and to benchmark our performance.

SKM was engaged to assess the reasonableness of the greenfield estimates used as the building blocks for EnergyAustralia's capital forecast. SKM reported that EnergyAustralia's greenfield estimates for electrical designs are reasonable and within seven to ten percent of the costs that SKM would estimate for similar projects.

The premiums applied by EnergyAustralia's estimators for brownfield work were also subject to external review by SKM and found to reasonably reflect the additional costs of brownfield work. SKM's report *EA Substation Cost Estimate Review* is included as Attachment 5.14.

SKM also assessed the design of major substation buildings built by EnergyAustralia and found that EnergyAustralia had a tendency to build marginally larger switchrooms than was required now that EnergyAustralia had selected slightly smaller 11kV switchgear. SKM recommended that standard switchroom design be reviewed to reduce building costs where possible.

SKM's recommendations have been accepted by EnergyAustralia and will be applied to future designs and related building standards. EnergyAustralia estimates that there is a three year lead time before project outcomes will be impacted by the streamlined designs, and these cost savings will be factored into costs of future projects during detailed planning.

SAHA International was also engaged to review the effectiveness of our asset management strategies and benchmark our performance. SAHA's report (Attachment 6.2) focussed largely on maintenance costs, but many of the findings are relevant to capital, particularly to brownfield replacement works.

SAHA's report found that:

"EnergyAustralia meets or exceeds best practice thresholds for asset management practices"[42]

42 Electricity Distribution Business Operational Expenditure Review, SAHA International, Feb 2008, p25.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

SAHA found that EnergyAustralia's asset type and location was the largest influence on maintenance costs and that higher costs were largely driven by factors outside of EnergyAustralia's control. These comments are equally true for brownfield construction and replacement work on EnergyAustralia's network as the assets and their location are the same. When these factors were excluded from the analysis, SAHA found that EnergyAustralia performed as well, if not better than other providers in maintaining the network. Labour costs were as low as could be expected and SAHA's analysis showed that in fact EnergyAustralia was undertaking more work at these low rates than its peers.

EnergyAustralia's replacement capital work is undertaken by our internal workforce. It follows that the findings that were made in areas of corrective and breakdown maintenance would hold equally true for brownfield capital replacement as both the staff and conditions are the same.

EnergyAustralia believes that the reports provided by SKM and SAHA demonstrate that our cost estimates are comparable to our peers when uncontrollable factors are taken into account. Our benchmarking illustrates that construction and maintenance work in a congested urban environment is relatively more expensive than similar work undertaken in less congested environments.

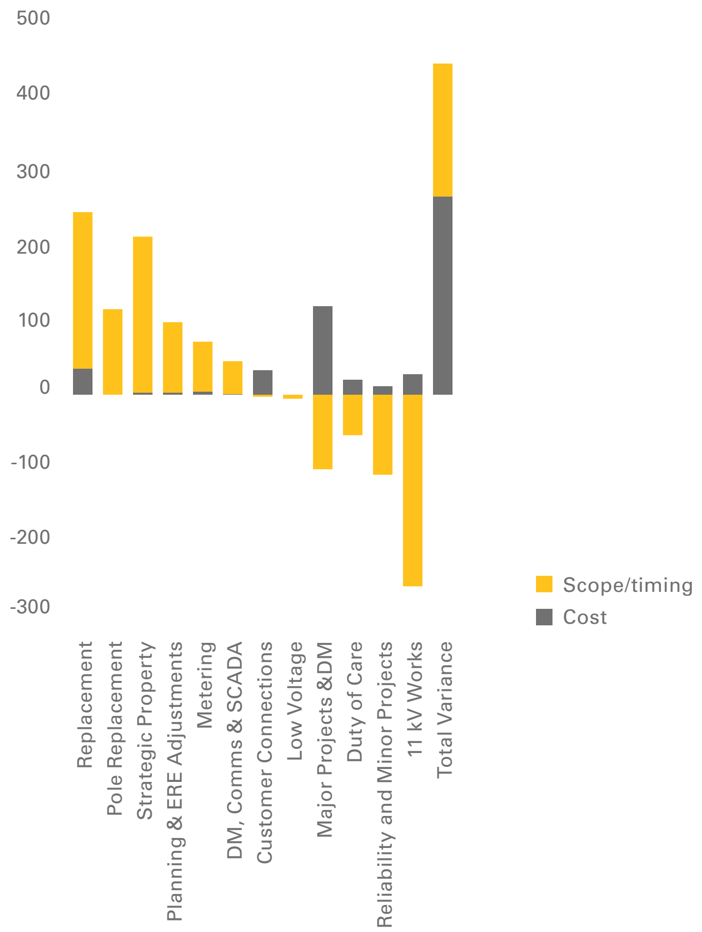
6.6.2 Comparison with past forecasts and actuals (capital expenditure Factor 5);

Figure 6.5 shows a program view of the difference between actual/planned capital expenditure and capital expenditure allowed under the combined IPART and ACCC revenue determinations for our system assets. It shows that EnergyAustralia has overspent its regulatory allowance by approximately $440 million (nominal) in the 2004-09 period.

The largest category of expenditure above the allowance was driven by replacement. Both IPART and the ACCC reduced EnergyAustralia's proposed replacement allowance in the 2004 and 2005 determinations. Despite this, EnergyAustralia has spent $357 million more than its allowance in replacement. This is driven in part by reactive replacement programs and a growing number of planned programs to systematically remove poorly performing equipment. In addition, expenditure on major replacement projects has increased as a result of scope and cost input changes as well as a carry-over of projects from the previous period. Strategic system property acquisition has also been a major contributor to higher than allowed expenditure. EnergyAustralia believes that these acquisitions were prudent purchases necessary to facilitate planned capital works in the 2009-14 period.

Changes to program scope particularly in metering (Time of Use meter roll-out), customer connections (higher cost connections) and major replacement works all contributed to higher expenditure levels.

Figure 6.5: EnergyAustralia's capital expenditure above the regulatory allowance set in 2004 ($m nominal)



Expenditure on 11kV works including reliability based investments is likely to be lower than the allowance and this is largely due to a lack of resources in these areas which is currently being addressed by EnergyAustralia.

EnergyAustralia has taken steps to improve its forecast accuracy for the 2009-14 period to avoid similar circumstances in 2014. Necessary expenditure in the current period that is above the regulatory allowance is not fully recoverable. This is because the incentives within the regulatory framework penalise expenditure above the regulatory allowance, even when this expenditure is efficient and prudent. EnergyAustralia is hopeful that improvements in forecasting accuracy, in the context of this incentive framework, and clearer principles of revenue regulation will allow it the opportunity to recover the costs of investing in the network in the next regulatory control period. Further explanation of the variances between forecast and historic capital expenditure can be found in Attachment 11.1.

6.6.3 Application of the regulatory test and other similar methodologies

A final indicator that EnergyAustralia can point to in order to demonstrate the efficiency of its expenditure forecasts is to demonstrate where the forecasts include expenditure that has already been subject to the regulatory test process. This is consistent with Transitional Rule 6.5.7(b)(4).

The projects in Table 6.2 in our current expenditure program have satisfied the regulatory test.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

Table 6.2: Projects that have satisfied the regulatory test (FY09 $m real)

Project Name	Forecast Costs 2009-14
Berkeley Vale ZN 132/11kV conversion	1.8
Brookvale ZN & 33kV feeder up-rate	21.5
Bunnerong STS 132kV feeder bays	1.0
Long Jetty ZN 66/11kV conversion	12.2
Nelson Bay Feeder Augmentation	5.5
New 132/11kV Adamstown zone substation	25.0
New Argenton 132/33/11kV substation	5.5
New City North 132/11kV zone substation	46.5
New Galston 132/11kV zone substation	9.3
New Kogarah 132/11kV zone substation	25.6
New Kooragang 132/33kV STS	11.9
New Mayfield West 132/11kV zone substation	6.2
New Scone 66/11kV zone substation	34.8
New Top Ryde 132/11kV zone substation	28.9
New Wamberal 132/66/11kV zone substation	35.0
Ourimbah STS refurbishment	27.3
Tomago BSP 132kV connections	20.6
New Port Botany 33/11kV zone substation	19.8
New Tomaree 33/11kV zone substation	21.9
New Bankstown 132/11kV zone substation	34.9
New Kurri 132/11kV zone substation	27.9
New 132kV feeders 245 and 246 (Feeders 908 & 909 replacement)	113.5

Outline of investment governance framework

EnergyAustralia's suite of Area Plans is based on up to date asset condition and performance information. The plans are also based on the most recent forecast of demand for future capacity. While the plans have been developed for a period of 20 years, in order to choose the most cost effective solution over the longer term, it is likely that at least some of the information that the plans are based on will change over time. The plans must therefore be sufficiently comprehensive to set a clear strategic direction for investments, but remain flexible enough to adapt to future needs and new information.

This combination of rigidity and flexibility is consistent with the AER's ex-ante investment framework which authorises a sum of money based on an initial suite of requirements, but allows for these funds to be spent in a different manner provided it is still spent efficiently.

EnergyAustralia manages this need for flexibility through its investment governance process which applies to all capital projects prior to authorisation. The investment governance process, shown in Figure 6.6 ensures that prior to any capital being committed projects are reviewed to ensure their optimality.

The first step in the governance process is to confirm the need for the investment. Once confirmed, the need is reviewed in light of the longer term strategies incorporated in the Area Plans.

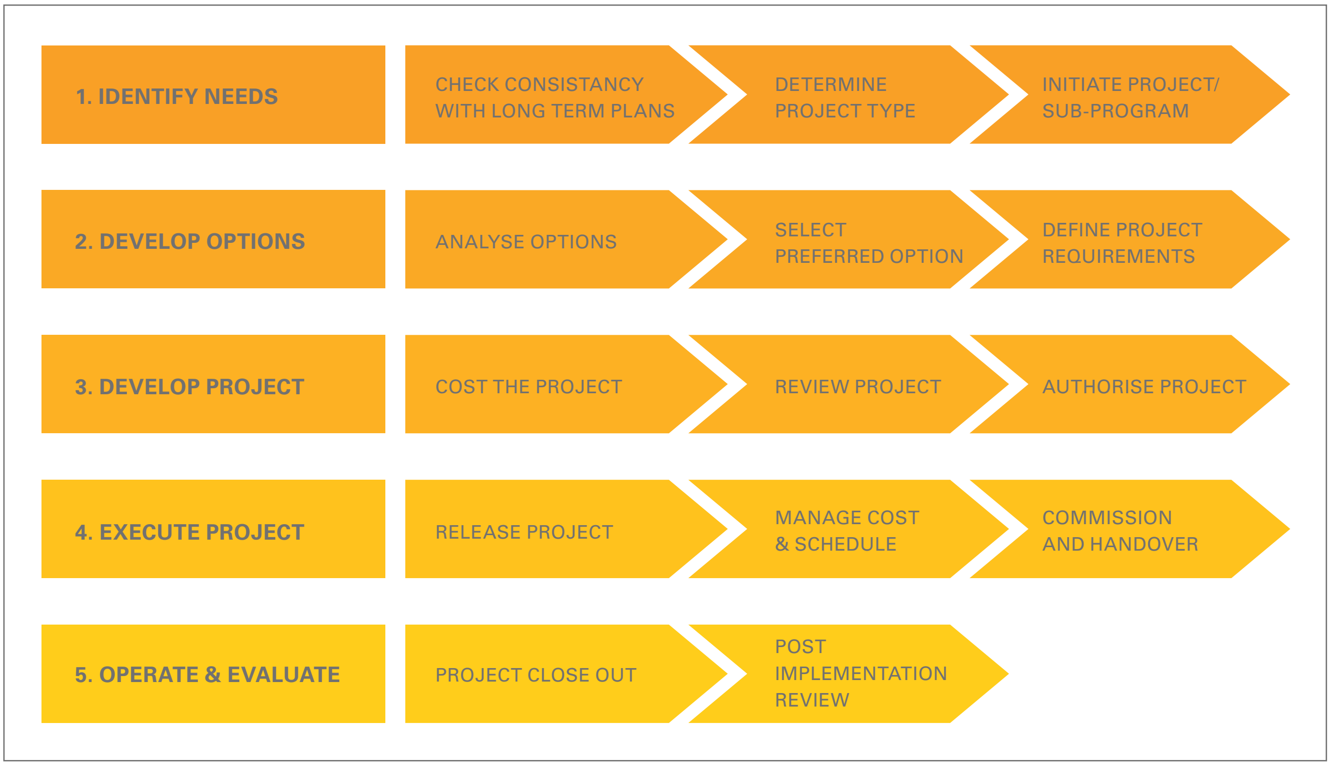
The second step is to develop project options to address the investment need. Several project options are developed and assessed for consistency with the Area Plan. A variety of project options are considered to ensure that the solution represents the least cost solution and therefore the most efficient use of constrained resources.

Once identified, the most efficient option is developed, scoped and costed during the third phase of the process, and finally submitted for authorisation.

The fourth and fifth stages of the governance process ensure that the project is delivered efficiently and that outcomes are consistent with the requirements.

All capital investments are planned, assessed and authorised using the capital governance process. However, the size, type and driver of a project will determine the specific investment gateways that apply.

Figure 6.6: Capital governance process



6. Aligning capital expenditure forecasts with Rule requirements (continued)

The governance process ensures that projects planned through the strategic network development process maintain their optimality throughout the project development phase. Not only are projects assessed for consistency against long term plans, they are reviewed and checked at various points in the process to ensure they continue to represent an optimal investment solution.

EnergyAustralia's investment governance framework is summarised in the Network Investment Governance Overview provided as Attachment 6.3 and documentation, templates and instructions are located on EnergyAustralia's internal procedures database.

EnergyAustralia's Replacement Plan also enables flexibility and therefore ensures it remains efficient over time.

The Replacement Plan is based on a set of replacement priorities, which may change over time based on the condition of network assets. The Plan represents the budget required to meet network needs over a 15 year period based on today's information and prioritisation of risks. The Plan is flexible, in that it can be updated to reflect the prioritisation of risks at a point in time. The Plan is managed by asset managers who also manage EnergyAustralia's maintenance program, and who therefore are experienced in analysing risks and the trade-off between maintenance and replacement.

EnergyAustralia believes the robustness of the investment plans together with the rigour of the investment governance process will ensure that EnergyAustralia is dynamically efficient over the course of the 2009-14 period.

EnergyAustralia has a robust joint planning process with TransGrid and with the other NSW DNSPs. EnergyAustralia conducts meetings regularly with these organisations to ensure that capital plans being developed within EnergyAustralia align with those other businesses. Joint planning with TransGrid is based on an agreed set of transmission planning criteria for the transmission network within EnergyAustralia's network area[43]. *The Joint Reliability Planning Criteria* signed by both TransGrid and EnergyAustralia are attached as Attachment 5.2.

EnergyAustralia's capital program reflects the joint plans agreed between TransGrid and EnergyAustralia to supply the regions north of Newcastle, the Central Coast and the Sydney Metropolitan Area. The plans are outlined in EnergyAustralia's transmission Area Plans and are based on plans that have been minuted in Joint Planning records held by both EnergyAustralia and TransGrid and represented in MoUs signed by both companies.

EnergyAustralia's Maitland Area Plan is based on the plans agreed between Country Energy, TransGrid and EnergyAustralia for the region north of Maitland in the Hunter Valley, and the Carlingford Area Plan is based on planning agreements with Integral Energy.

Effective joint planning ensures that outcomes are designed to maximise benefits for all network providers.

EnergyAustralia believes that it has established a capital planning methodology that enables dynamic efficiency, and is predicated on obligations that act as a proxy for allocative efficiency. Finally, EnergyAustralia believes that the process that it has used to forecast the capital expenditure requirements has been built to deliver productive efficiency. EnergyAustralia believes that its forecast program of capital works is economically efficient in the circumstances.

6.6.4 Out-sourcing to non-related parties (capital expenditure Factor 9)

The extent to which a DNSP engages in contracts that are at arms length (or not at arms length) is a factor the AER is required to consider in its assessment of capital forecasts. EnergyAustralia does not consider that any part of its forecast capital expenditure is referable to arrangements (with another party) that do not reflect arm's length terms.

EnergyAustralia outsources a large portion of work to independent contractors including all cable laying, reinstatement, civil building and tunnel construction, civil design, vegetation management, and pole inspections.

In addition, ASPs compete for work with our own energy service provider to engage in distribution connection activities. These assets are generally gifted to EnergyAustralia, to operate and maintain.

43 The Reliability, Planning and Design Criteria introduced by the Minister for Energy in NSW do not apply to TransGrid. However, EnergyAustralia and TransGrid have agreed to a set of criteria that was consistent with the planning criteria that applied to distribution businesses.

Electrical design work for distribution network assets is also contestable. This allows effective use of internal resources and also helps to capture innovative designs where they are shown to be optimal.

EnergyAustralia out-sources a wide variety of work to the market via competitive tender processes. EnergyAustralia has used cost estimates from recent capital projects in its program's building blocks, as this reflects the market prices for these services in the current environment.

EnergyAustralia has designed its outsourcing strategies to maximise the effective use of limited internal resources. It also facilitates a market within the wider community for services which provides greater output flexibility over time as the external workforce can be harnessed to deliver large amounts of work where necessary.

Competitively tendered work makes up between 60-70 percent of EnergyAustralia's total capital expenditure. The remainder is EnergyAustralia's internal labour cost, which contributes between 30 and 40 percent depending on whether the program is predominantly greenfield or brownfield construction.

Strategic procurement

EnergyAustralia has moved away from procuring equipment for specific projects to a more strategic procurement model whereby supply contracts are negotiated for several years. EnergyAustralia's supply contracts typically lock in production slots and thereby ensure that equipment can be delivered when required with minimal warehousing time. Our 11kV cable supplier warehouses stock and delivers specific cut lengths to sites within 24 hours.

The new supply arrangements typically include rise and fall clauses in the price of contracts, which acts as a risk sharing mechanism between EnergyAustralia and its suppliers to manage real input cost increases.

EnergyAustralia is aware that the capital program in 2009-14 is substantially higher than previous periods and negotiations are already underway to ensure key equipment is available when required.

EnergyAustralia is actively seeking a standardisation of its supply requirements to ensure that it can maintain a position as a preferred customer and further guarantee future supplies.

Project management

EnergyAustralia has a detailed system of project management and progress reporting. EnergyAustralia applies high quality project management to all major projects undertaken.

EnergyAustralia has a detailed program reporting process whereby all major projects and capital programs are reported monthly to Executive Management. This reporting is managed by the same group that tracks projects in development. This allows feedback on planning time, delivery expectations and costs to be fed back within the process.

6.7 EnergyAustralia's demonstration of a realistic expectation of cost inputs and demand forecasts

The Rules require the capital forecast to be assessed in terms of whether it reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives. EnergyAustralia believes that its proposed capital program represents both these principles.

EnergyAustralia is confident that processes used to develop the demand forecast are reasonable and will withstand scrutiny by experts. Furthermore, EnergyAustralia believes that the total cost of investments proposed for the 2009-14 is reasonable in the circumstances and that the investments themselves represent is a reasonable reflection of what is required to deliver customer and network outcomes.

6.7.1 Demand forecasts

EnergyAustralia has summarised its approach to developing demand forecasts in 4.2.1. In addition to the standard development process, EnergyAustralia discussed how it has made a number of high level adjustments to its capital forecast to account for the potential impact of demand management and future price elasticity on the timing of growth driven investments.

6. Aligning capital expenditure forecasts with Rule requirements (continued)

6.7.2 Demand management

EnergyAustralia is obliged to meet or manage demand. EnergyAustralia is an industry leader with respect to demand management (DM) and has an extensive track record of implementing demand management projects that defer capital investment and influence energy consumption behaviour. The likely impact of DM has been explicitly taken into account in the capital program. However application of DM to the program has been factored in at a global level. This approach is explained below.

Tariff based demand management

There are two types of DM – tariff based, and DM undertaken to defer a specific capital investment in a specific location. Both these types are able to defer investments related to demand growth.

EnergyAustralia has used findings from its analysis of customer response to Time of Use (ToU) tariffs and the subsequent review by Charles River & Associates (CRA) to determine the likely impact of tariff based DM initiatives on peak demand and energy growth. EnergyAustralia found an average 1.1 percent drop in demand coincident to the summer system peak for customers subject to ToU pricing initiatives, compared to those who were not.

CRA found that EnergyAustralia can expect a reduction in long term peak demand of affected customers as a result of ToU pricing initiatives by 2014. The CRA report cautions against making changes to forecasts at this early stage of pricing research, particularly due to the structural impediments associated with network pricing signals being passed on by independent energy retailers[44]. Despite these concerns, EnergyAustralia believes that the Australian public's heightened awareness of climate change and its impact will lead to some change in consumer behaviour and energy consumption over the regulatory period. EnergyAustralia has therefore taken the CRA findings into account and has made an explicit adjustment to the growth related capital forecast in the period. This adjustment considers the proportion of peak demand attributable to these ToU customers and other factors such as the long and short term elasticity of demand.

This adjustment is made to the capital program at the end of the planning process by means of applying a percentage adjustment to the portion of capital expenditure that is related to growth. The methodology for applying this adjustment to the capital forecast is outlined in Attachment 5.13 – DM Impact on Capital Forecast.

Demand management for capital deferral

EnergyAustralia has not forecast specific DM projects to defer capital or take into account the forecast of growth driven capital expenditure. This is because DM projects generally cannot be forecast two to seven years in advance. Capital deferral through DM can only be sought when a supply side project's scope, timing and cost is known with certainty. Demand management projects of this type are location and timing specific and often involve contracts for specific customer behaviour (i.e. interruptible load). It is impossible to predict the take-up of these types of initiatives in locations that are yet to be finalised, with customers who may not yet live or work in that location.

EnergyAustralia has a long standing commitment to investigate DM projects as part of its capital governance process. All material growth related capital projects are investigated for DM options via a screening study and DM investigation. Where DM projects are identified as feasible and economic to defer capital expenditure, they are implemented and the costs of the DM project recovered via IPART's D factor mechanism. EnergyAustralia proposes to continue to use this process[45] for growth related capital projects in the 2009-14 period.

During the 2003-07 period, DM impacted approximately $58 million worth of capital investment and resulted in a capital deferral benefit of $9 million at a cost of $5 million.

44 The initial findings from CRA as part of Attachment 6.4: Impacts of Time of Use on Demand and Energy Forecasts.

45 The AER has indicated that it will implement a similar style of D factor to that used by IPART in order to continue to encourage demand side investments.

EnergyAustralia's experience has shown limited scope for effective network DM relative to the overall requirement for growth capital. However, as part of its commitment to DM, EnergyAustralia has applied these results to the 2009-14 period by making a high level adjustment to the forecast based on the costs and benefits project based DM could be expected to deliver during the period. The calculations used are included in Attachment 5.13.

Effect of climate change

EnergyAustralia acknowledges the evidence of climate change and believes that it is prudent to consider its impact on customers' electricity usage.

Warmer temperatures are likely to reduce the amount of energy required for space heating, but are also likely to increase the energy required to air condition premises during hotter days. Given that spatial forecasts consider the peak demand at specific locations, it is possible that the impact of climate change could lead to an increase in spatial forecasts as a result of greater demand for capacity on peak days. This view does not take account of the potential for customers to make a behavioural response to climate change.

The record peak demand which occurred during extreme weather conditions in Victoria over the 2007-08 summer holiday period suggests that despite customers' general concern and awareness of climate issues, during times of extreme weather conditions, customers will choose to use electricity to manage these conditions (i.e. air condition their premises).

It is electricity demand on *peak* days that drives the (location specific) spatial forecast and in turn drives capital investment requirements which result from forecast network capacity constraints.

EnergyAustralia has not made a specific adjustment to its spatial forecast to account for the uncertain impact of climate change because there is little evidence upon which to forecast potential behavioural change at specific locations during peak temperature days in the future. However, EnergyAustralia has considered the impact of general behavioural response on its capital program as a result of tariff based initiatives as discussed.

6.7.3 Cost inputs

EnergyAustralia has detailed its approach to establishing cost inputs in the discussion of each investment plan included in Chapter 5. A document setting out the cost estimation methodology and process is also included as Attachment 5.4.

CEG's recommended escalation factors have been applied to the capital program forecast to ensure that future estimates are an appropriate reflection of future costs.

6.8 Conclusion

The Transitional Rules require the AER to accept the total of EnergyAustralia's capital expenditure forecast, if it is satisfied that the forecast reasonably reflects the capital expenditure criteria (taking into account the capital expenditure factors). There are ten such capital expenditure factors.

As an underlying theme, this chapter identifies the discretion afforded to the AER in making a decision on its satisfaction with the efficiency and prudency of EnergyAustralia's capital expenditure forecast.

For EnergyAustralia, the 2004-09 regulatory period was characterised by a requirement for capital expenditure well in excess of that allowed in the regulatory determination. The reasons for this, and the efficiency of its delivery, provide an important insight into the challenges to be met in the 2009-14 regulatory period.

This chapter describes in some detail EnergyAustralia's consideration of the capital expenditure criteria and the capital expenditure factors. The potential consequence of using alternative planning options and processes is also analysed, in order to provide the AER with sufficient information to satisfy itself that the forecasts presented represent the efficient costs of a prudent DNSP operating in our particular circumstances, to meet the capital expenditure objectives.

7. Depreciation

The purpose of this chapter is to outline the depreciation building block that has been calculated under the Rules and in accordance with EnergyAustralia's completed PTRM. This is supported by an explanation of the depreciation schedules used in the calculation of the annual revenue requirement. These schedules have been calculated in accordance with the Rules.

RULE REQUIREMENTS

(TRANSITIONAL RULES 6.5.5, 6.12.1(8), 6.12.1(2))

The AER's determination is predicated on its decision whether to approve or not to approve the depreciation schedules submitted by EnergyAustralia as part of its Regulatory Proposal[46].

Transitional Rule 6.5.5(a) requires that depreciation must be calculated on the value of the assets included in the RAB at the beginning of each regulatory year and on the basis of depreciation schedules submitted by EnergyAustralia if those schedules conform to the requirements in 6.5.5(b) and contain the matters specified in Sch 6.1.3(12).[47]

7.1 Summary

EnergyAustralia proposes the building blocks include the following allowance for depreciation:

Table 7.1 Depreciation building block (FY09 $m real)

	FY10	FY11	FY12	FY13	FY14
Depreciation	278	335	388	446	472

In accordance with clause 6.5.5, these amounts:

- have been calculated on the value of the assets in EnergyAustralia's RAB as at the beginning of the regulatory control period and for each year of the regulatory control period thereafter;
- are developed in accordance with the asset roll forward and post tax revenue models;
- are based on a straight-line method of depreciation over the weighted average remaining economic lives of the asset classes for assets within the opening RAB;
- are based on straight line deprecation over the standard economic life applied to forecast capital expenditure within the 2009-14 regulatory period. EnergyAustralia believes this approach is a reasonable reflection of the nature of the assets;
- are developed on the basis that the sum of the real value for any asset over its economic life (such real value being calculated as at the time the value of that asset was first included in the RAB) must be equivalent to the value at which that asset or category of assets was first included in the RAB; and
- are therefore calculated using depreciation methods and rates that are consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

The attached document *EnergyAustralia Depreciation Schedules* (Attachment 7.1) provides the depreciation schedules in accordance with *Clause 6.5.5* of the Transitional Rules.

These schedules categorise the relevant assets for these purposes by 37 different asset classes.

EnergyAustralia has separately categorised these asset classes for depreciation into transmission and distribution components. This assists in the calculation of the separate revenue requirements for transmission for the purposes of deriving the X factor and pricing. This is discussed in more detail in Part II of the Regulatory Proposal.

The remaining asset lives are established via rolling forward the 2004 values, adjusted for actual net capital expenditure and depreciation to 1 July 2009. The calculation of the remaining asset lives as at 1 July 2009 is demonstrated in the transmission and distribution roll forward models.

46 Transitional Rule 6.12.1(8)

47 Transitional Rules 6.12.1(2)

7.2 Variations to asset classes

EnergyAustralia proposes the addition of four new asset classes. This has arisen because of the use of new technology in these asset classes. The exception to this is the new asset class IT – Direct System, which is proposed to improve transparency. It is proposed that the existing assets remain as asset classes with their current asset lives. However, new assets will be added to the new asset classes that operate in parallel to the existing asset classes. This approach retains transparency between old and new assets, while properly reflecting the true economic and technical life of the new assets.

Ancillary substation equipment (15 year standard life)

Ancillary Substation equipment comprises control and protection equipment within zone and subtransmission substations. Historically, this equipment was electro-mechanical that was either not separately identified and given the same life as substation equipment generally (45 years) or if identified had a physical life of 10-25 years. This equipment is now predominantly digital in nature and a life of 15 years has been applied to this equipment on the basis of the future expected life of this equipment. This is consistent with the AER's decision in ElectraNet's Transmission Determination for a new asset class of substation secondary systems – electronic with a life of 15 years.

IT – Direct System (seven year standard life)

IT expenditure which is directly attributable to system assets has been added under this new asset category rather than non-system IT. The same asset life of seven years which has historically applied to non-system IT has been used. A new asset class is proposed to allow improved management of this class of asset.

Communications (digital) – (ten year standard life)

Network communications has also moved away from analogue equipment to digital equipment. Existing equipment had lives of between 10-25 years. This equipment is also predominantly digital in nature and a life of ten years has been applied to this equipment on the basis of the future expected life of this equipment. The ten year life is based on industry experience with this type of equipment.

Customer Metering (digital) – (15 year standard life)

Customer metering has also moved away from analogue equipment to digital meters. Previously this equipment had a regulatory life of 25 years. This equipment is now predominantly digital in nature and a life of 15 years has been applied to new metering equipment on the basis of the future expected life of this equipment. Digital metering is the same technology type as electronic secondary systems which has an approved 15 year life.

7.3 Asset lives

The standard life of an asset is the expected life of an asset that has been operated and appropriately maintained. It considers both the technical or engineering life as well as the economic life. The life of individual assets may differ from the standard life but on average, the standard life should equate to the average life for a particular class of asset.

With the exception of the new asset classes above, EnergyAustralia has applied the same standard asset lives for the 2009-14 regulatory period as was approved by IPART for the 2004-09 regulatory period. EnergyAustralia has assessed that the standard asset lives used in the 2004-09 regulatory period continue to reflect the economic life of those assets, and is consistent with the requirements of the Transitional Rules. EnergyAustralia's basis for using these asset lives is based on a review carried out by Burns and Roe Worley on behalf of IPART in April 2004. This review can be found at Attachment 7.2: BRW Report: Review of EnergyAustralia's Asset Lives.

7.4 Conclusion

The depreciation provisions which EnergyAustralia has included in its proposal are straightforward, using the straight line method over the weighted average lives of asset classes. The approach is in accordance with the Rules and the AER's PTRM.

8. Rate of Return

The purpose of this chapter is to demonstrate that the rate of return used to calculate the return on capital for each year of the regulatory control period:

- is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by EnergyAustralia; and
- is calculated as a nominal post-tax weighted average cost of capital ("WACC") in accordance with Clause 6.5.2 of the Transitional Rules.

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(5), 6.1.3(9), 6.5.2)

The AER's determination is predicated on a decision in relation to the rate of return in accordance with Clause 6.5.2[48].

EnergyAustralia's calculation of the proposed rate of return must be included in its Building Block Proposal[49].

8.1 EnergyAustralia's rate of return

EnergyAustralia has calculated a post-tax nominal WACC of 9.80 percent. This has been calculated:

- utilising the deemed parameters specified in the Transitional Rules;
- using the calculations and parameters prescribed in the Transitional Rules and predefined in the PTRM; and
- using market parameters consistent with those observed by the AER in previous regulatory decisions.

8.2 Methodology and calculation

The methodology, formula and parameters for calculating the WACC are provided in Clause 6.5.2 of the Rules. The Rules require the WACC to be calculated in accordance with the following formula:

$WACC = k_e * E/V + k_d * D/V$

where:

$\mathbf{k_e}$ is the return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

$r_f + ß_e * MRP$

where:

$\mathbf{r_f}$ is the nominal risk free rate for the regulatory control period determined in accordance with paragraph (3);

$\mathbf{ß_e}$ is the equity beta, which is deemed to be 1.0;

MRP is the market risk premium, which is deemed to be 6.0 percent; and

$\mathbf{k_d}$ is the return on debt and is calculated as:

$r_f + DRP$

where:

DRP is the debt risk premium for the regulatory control period determined in accordance with paragraph (e);

E/V is the market value of equity as a proportion of the market value of equity and debt, which is 1 – D/V; and

D/V is the market value of debt as a proportion of the market value of equity and debt, which is deemed to be 0.6.

48 Transitional Rule 6.12.1(5)
49 Transitional Rule Schedule 6.1.3(9)

The parameters used by EnergyAustralia in arriving at the proposed rate of return are set out in Table 8.1 below[50]:

Table 8.1: WACC parameters and values in the PTRM

Parameter	Value
Nominal Risk Free Rate	6.09
Real Risk Free Rate	3.46
Inflation Rate	2.54
Cost of Debt Margin over r_f	2.11
Nominal pre-tax cost of debt	8.20
Real pre-tax cost of debt	5.50
Market Risk Premium	6.0
Proportion of Equity Funding	40.0
Proportion of Debt Funding	60.0
Equity Beta (uses T_e)	1.0

The above table was extracted from the PTRM. Nominal risk free rate, inflation rate and debt margin are the only user inputs into the model. Two of these inputs are discussed below. Further information on inflation rate is discussed in chapter 1.3.

The AER is required to make a decision on the numbers used for the following parameters associated with the WACC formula.

8.2.1 Nominal risk free rate

The Rules require the nominal risk free rate to be determined by the AER on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using the indicative mid rates published by the Reserve Bank of Australia and a period of time agreed with the AER. EnergyAustralia has proposed a period for establishing the moving average in Attachment 8.1: "Proposed period for establishing the moving average of the Nominal risk free Rate."

EnergyAustralia notes that its proposed period may be kept confidential but only until after the expiry of that period. However EnergyAustralia also notes the AER will inform the DNSP within 30 days of submitting the Regulatory Proposal whether it agrees with the proposed agreed period[51].

8.2.2 Debt risk premium

Transitional Rule 6.5.2(e) requires the AER to determine the debt risk premium for the regulatory control period. EnergyAustralia proposes that the debt risk premium be calculated as the observable difference between the risk free rate and the cost of debt (for BBB+ rated securities) calculated by the use of a moving average over the "agreed period". EnergyAustralia submits that long-term corporate bond data observations should be sourced from the Bloomberg service. This approach is supported by CEG in Attachment 8.2 "Nominal risk free rate, debt risk premium and debt and equity raising costs for EnergyAustralia".

Recognising the difficulty associated with obtaining corporate bond information with a 10 year maturity, EnergyAustralia proposes that the AER adopt the same estimation techniques as it employed in the recent AER SP AusNet decision (also supported by CEG).

8.3 Conclusion

For the purpose of providing an indicative price path in the regulatory submission, EnergyAustralia has calculated a nominal post-tax WACC of 9.80 percent. This is based on market parameters consistent with recent AER regulatory determinations.

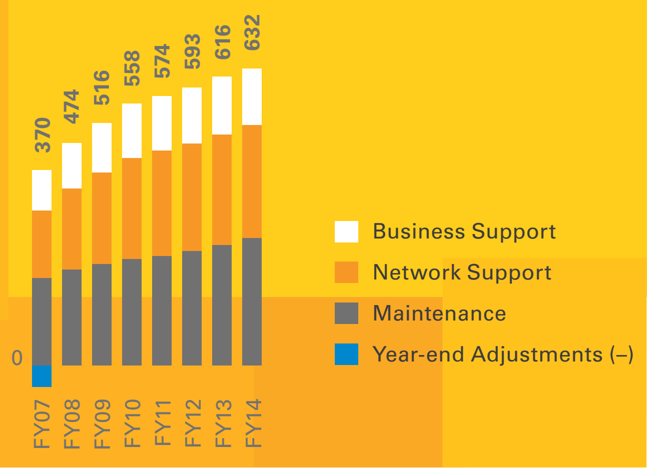
Actual market parameters will be used to calculate the value of WACC in the AER's determination. EnergyAustralia has advised the AER in Attachment 8.1 of the observation period for those parameters. This attachment will be kept confidential until after the expiry of the period.

50 Parameters are indicative only. Where necessary, EnergyAustralia has used parameters adopted by the AER in the SP Ausnet final decision as a proxy.

51 Transitional Rule 6.5.2 (c)(2)

9. Operating expenditure forecast methodology

Figure 9.1: Operating expenditure forecasts 2009-14 (FY09 $m real)[53]



EnergyAustralia's operating expenditure forecast and the methodology used to derive the forecast are described in the next three chapters.

The purpose of this chapter is to:

- summarise the methodology to determine operating expenditure EnergyAustralia requires to achieve the operating expenditure objectives during the period;
- outline how EnergyAustralia's key obligations (combined with network requirements) influence operating expenditure requirements;
- explain how the various cost activities to meet the operating expenditure objectives are categorised into three main areas; and
- highlight the obligations, objectives and forecasting approach for each cost category.

In Chapter 10, we describe what EnergyAustralia considers to be the operating expenditure for the 2009-14 period required to meet the operating expenditure objectives. This starts with the establishment of an efficient starting point to escalate costs. Then we forecast changes in cost activities based on work, price and volume drivers and the function changes (step changes) for the period 2009-14.

In Chapter 11, EnergyAustralia uses the factors that the AER must consider under the Rules to explain why the operating expenditure forecast is a reasonable reflection of the efficient costs of a prudent DNSP operating in similar circumstances to that of EnergyAustralia

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.5.6(a))

A Building Block Proposal must include the total forecast operating expenditure which EnergyAustralia considers is required to achieve each of the following (the operating expenditure objectives)[52]:

(1) meet or manage the expected demand for Standard Control Services;

(2) comply with all applicable regulatory obligations or requirements;

(3) maintain the quality, reliability and security of supply of Standard Control Services; and

(4) maintain the reliability, safety and security of the distribution system.

9.1 Summary

The total forecast operating expenditure EnergyAustralia requires to meet the capital and operating expenditure objectives is $2.97 billion (FY09 real) during the 2009-14 period. Including debt and equity raising costs operating expenditure is forecast at $3.07 billion during the 2009-14 period.

The forecast annual expenditure for each year of the regulatory control period is shown in Figure 9.1.

The operating expenditure forecast is broken into three components:

- network maintenance;
- network support; and
- business support.

EnergyAustralia determined this forecast based on its view of the efficient level of expenditure for a business of EnergyAustralia's size and circumstance to meet its obligations and achieve the outcomes recognised by the operating expenditure objectives in the Rules.

52 Transitional Rule 6.5.6(a)

53 Excludes debt and equity raising costs

9.2 Key inputs and assumptions

EnergyAustralia's operating expenditure forecasts are based on a series of underlying assumptions on changes to current circumstances over the period.

The key assumptions underlying EnergyAustralia's forecast are included in EnergyAustralia's response to the AER's regulatory information template 2.3.3. In accordance with the Rules, these assumptions have been certified as reasonable by EnergyAustralia's Directors. The Directors' certification accompanies the Building Block Proposal.

9.3 Forecast process summary

The process EnergyAustralia has used to forecast operating expenditure costs over the 2009-14 period can be summarised as follows:

1 – Operating expenditure objectives: EnergyAustralia has identified future costs by reference to the operating expenditure objectives and its network and business obligations. Section 9.4 outlines the how operating costs are linked to objectives and how many of the functions required by EnergyAustralia as a business relate directly to regulatory and legislative obligations.

2 – Establish a forecast approach by cost category: Operating expenditure requirements are fundamentally influenced by:

- the obligations imposed on the business (described in Section 9.4); and
- the electrical asset base and the changes to that asset base over time. These changes manifest themselves through an increase in the size of the asset base, changes to the customers numbers, or a change in the condition of the assets within the asset base.

These two influences combined generate a multitude of costs across the network.

EnergyAustralia's costs are allocated into cost activities across its divisions to meet the requirements of the electrical asset base and the customers connected to it over the regulatory period.

The forecast operating expenditure is built up at the activity level which allows costs of related tasks undertaken across Divisions to be analysed and reported together. These 'activity groups' are mapped to three high level 'operating cost categories':

- maintenance costs;
- network support costs; and
- business support costs.

3 – Establish a starting point for forecast: EnergyAustralia has used the last auditable financial accounts as the basis for deriving the "starting point" for the forecast of operating expenditure in the 2009-14 period. EnergyAustralia has reconciled actual expenditure to the allowances established by IPART and ACCC in 2004 and 2005, adjusting them for the approved pass through of costs associated with introduction of the DRP licence conditions.

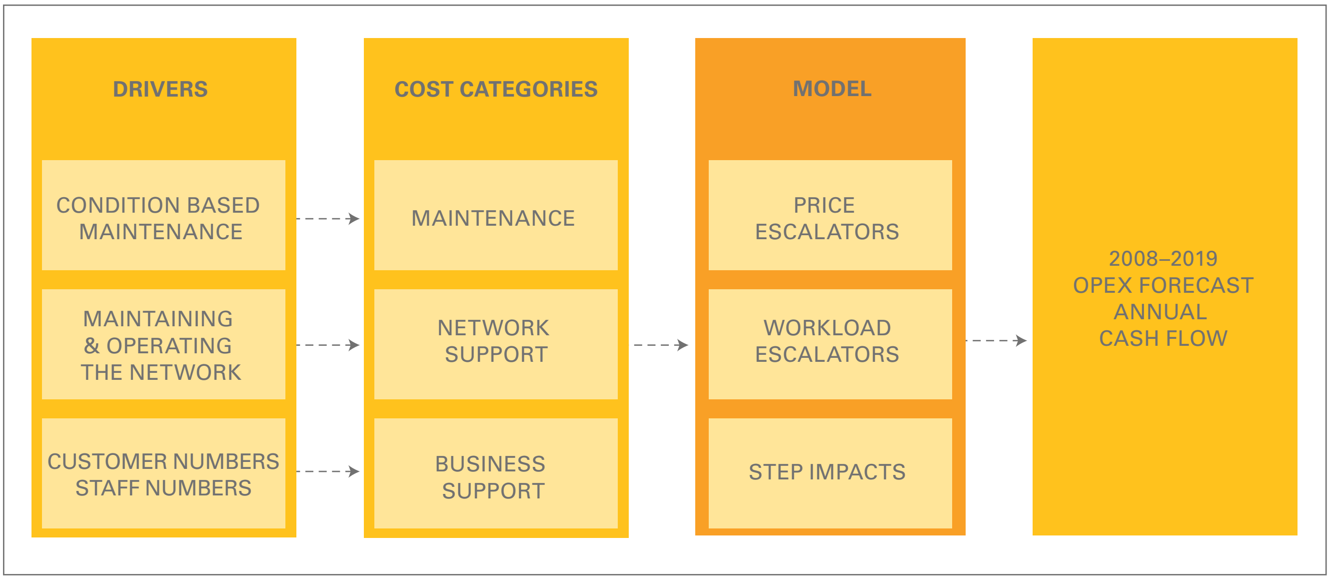
EnergyAustralia has explained variances between what was expected to occur in 2004 and the actual results in 2006-07 by assessing the changes in cost of specific activities. This variation is explained further in terms of outcomes likely in 2008-09. This analysis shows the impact of forecasting errors at the beginning of the period, and the compounding nature of these errors over time.

EnergyAustralia has used the 2006-07 year to establish a starting point for each activity performed by EnergyAustralia which, in aggregate, sum to the efficient starting point for the forecast. This is explained in Chapter 10.

9. Operating expenditure forecast methodology (continued)

4 – Identify future movements in activity costs: EnergyAustralia has identified drivers of step changes to operating costs at each activity level to ensure that step changes in obligations or requirements in a particular activity are captured. EnergyAustralia has linked forecast costs to drivers of cost movements which include general workload drivers and input cost escalators. This means that operating expenditures vary with input costs (eg the cost of labour) and also vary with workload (eg greater number of assets on the network require greater back office costs, more switching and more maintenance). This is explained in Chapter 10.

Figure 9.2 Overview of forecasting process



9.4 Understanding operating expenditure in the context of the objectives and obligations

EnergyAustralia's operating expenditure program is linked to a range of obligations that influence the way in which EnergyAustralia operates and maintains its network and runs its business. Compliance with these obligations is a key driver of operating costs, and is consistent with, and is specifically acknowledged by, the operating expenditure objectives (see in particular Objective 2).

EnergyAustralia's legislative and regulatory obligations are set out in Attachment 4.1. However, this section provides a brief overview of the key obligations or requirements that are relevant to the operating expenditure forecast contained within this proposal. All of these obligations, except some of those associated with running the business, are considered to be regulatory obligations or requirements.

EnergyAustralia's obligations can be summarised into five key categories similar to the way in which the capital expenditure obligations can be grouped:

1. Obligation to connect and meeting contractual obligations to customers;
2. Network planning, operation and management;
3. Network design, reliability, performance and service standard obligations;
4. Network safety, security and management; and
5. Obligations associated with running the business.

1. Obligation to connect and meeting contractual obligations to customers

Under the *NSW Electricity Supply Act (1995)* EnergyAustralia must have a Standard Form Customer Contract that

- applies to all customers connected to its network; and
- complies with certain specified requirements.

This contract and the associated statutory requirements impose a range of obligations upon EnergyAustralia including guaranteed service levels, billing, fault reporting and inquiry (call centre) services, disconnection procedures and availability of an energy industry ombudsman.

These obligations are supplemented by NSW specific Market Operations Rules (made under the *Electricity Supply Act)* relating to:

- arranging connection services;
- network use of system arrangements with retailers; and
- metering.

In addition the Electricity Supply (Safety and Network Management) Regulation 2002 imposes an obligation upon EnergyAustralia to develop and implement a Customer Installation Safety Plan. Under Chapter 5 of the National Electricity Rules, EnergyAustralia must operate a full connection inquiry service where appropriate to facilitate negotiation of a connection agreement. Chapter 7 of the Rules imposes a range of metering service related obligations including Responsible Person functions and the operation of a Network Metering Identifier (NMI) discovery service.

Expenditure to connect and meet contractual obligations is required to meet operating expenditure Objective 1 – to meet or manage demand, and Objective 3 – to maintain the quality, reliability and security of supply of Standard Control Services.

2. Network planning, operation and management

EnergyAustralia must have in place and implement the following plans under the *Electricity Supply (Safety and Network Management) Regulation 2002*:

- Network Management Plan (Attachment 4.2);
- Customer Installation Safety Plan (Attachement 9.1);
- Public Electrical Safety Awareness Plan (Attachment 9.2); and the
- Bushfire Risk Management Plan (Attachment 4.2).

These plans must be implemented, regularly reviewed, made publicly available, and reported against at least annually in an annual performance report.

9. Operating expenditure forecast methodology (continued)

Expenditure to meet these obligations is required to achieve Objective 2 directly. However, this expenditure also enables EnergyAustralia to achieve outcomes consistent with Objectives 3 and 4.

The National Electricity Rules impose a range of obligations which require the operation of sophisticated business processes and information systems. These include:

- system operation and power system security to meet NEMMCO requirements including communications facilities (Chapter 4 of the Rules);
- network planning and development planning reports and joint planning (Chapter 5 of the Rules); and
- MSATS, B2B and EHub systems compatible with NEMMCO systems (Chapter 7 of the Rules).

Expenditure to maintain and operate these systems ensures that EnergyAustralia achieves Objective 2, but is also necessary to achieve Objectives 3 and 4.

3. Network design reliability, performance and service standard obligations

Network design, reliability, performance and service standard obligations are now principally imposed by the DRP licence conditions and the National Electricity Rules. These conditions are discussed and explained in more detail in section 4.1. The DRP licence conditions require reports and an annual audit on:

- design planning criteria;
- reliability standards;
- individual feeder standards;
- customer service standards; and
- major incidents reporting.

The NER require EnergyAustralia to provide power system security support and local black start procedures and systems.

4. Network safety, security and management.

Network safety, security and management obligations are general in nature and are not directed specifically at DNSPs and electricity networks. The core obligations are derived from the NSW Occupational Health and Safety Act, the Protection of the Environment Operations Act and obligations to identify and manage risks associated with the network.

5. Obligations associated with running the business

Obligations in this category generally align with the business support cost category discussed in Section 9.8.

EnergyAustralia has a number of obligations requiring it to operate its business in line with obligations applying generally to Australian corporations, and all businesses in EnergyAustralia's circumstances would need to comply with these general obligations.

In addition, EnergyAustralia is obliged to comply with the requirements of the *State Owned Corporations Act 1989 (NSW)* including the *Public Finance and Audit Act, 1983*[54].

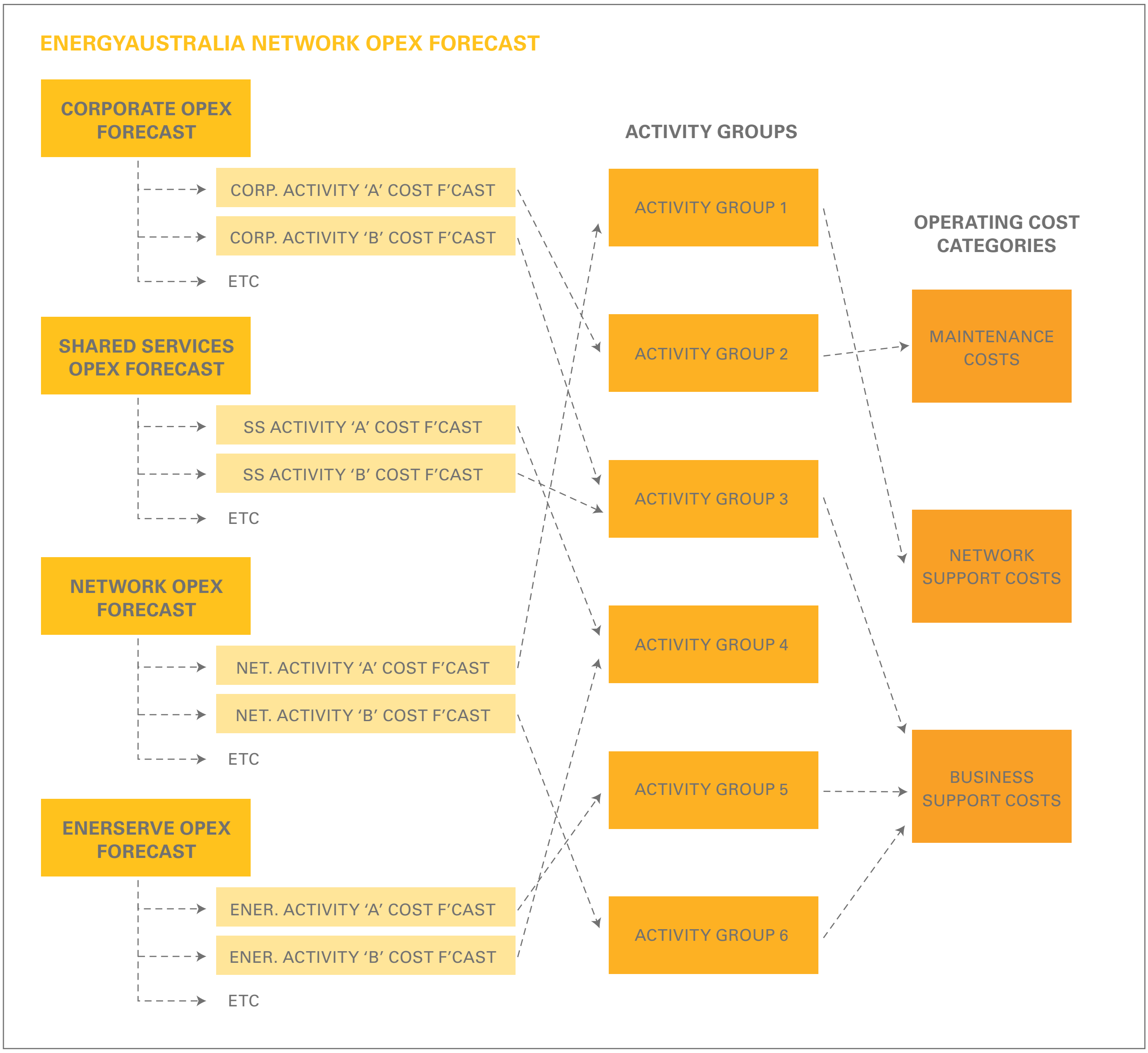
These obligations encompass annual and financial reporting, accounting, compliance and auditing systems, finance and Treasury functions, meeting Freedom of Information requests and NSW Ombudsman inquiries and preparing Statements of Corporate Intent.

These obligations can be grouped into:

- corporate support and governance; and
- risk management, regulation and compliance.

54 It should be noted that some obligations are specific to State Owned Corporations. However, these obligations reflect the circumstances of EnergyAustralia and are therefore a relevant consideration.

Figure 9.3: EnergyAustralia's approach to operating expenditure mapping



9. Operating expenditure forecast methodology (continued)

9.5 Cost categories

EnergyAustralia has forecast its operating costs using 18 activities. Each activity combines the costs of related tasks even where aspects of the task occur in different divisions. These 'activity groups' are, in turn, mapped to three high level 'operating cost categories':

Maintenance costs – includes electrical system maintenance and network control costs. These costs are driven by asset type, asset condition, the quantity of assets, and EnergyAustralia's maintenance philosophy.

Network support costs – costs that directly support the operation of the system. Examples include operation and maintenance of network IT systems such as GIS, OMS, DNMS etc. These costs are driven by asset quantity, size of capital program, and customer numbers.

Business support costs – costs that relate to operation of the business itself that typically would exist in any business. These costs are related to customer numbers and staff numbers

Maintenance costs are directly influenced by the replacement of assets and the existing costs associated with the condition of aged assets. The remaining two categories of operating costs – network support and business support costs – while not directly linked to the capital program, are still influenced by the existing asset base and forecast capital expenditure program.

9.6 Maintenance costs

The maintenance cost category includes network maintenance costs and a portion of back office costs associated with scheduling, reporting, and managing maintenance activities.

Objectives and obligations

EnergyAustralia is subject to obligations that extend from the ownership, management and investment in electricity works which manifest as operating expenditures.

Network maintenance is directed at Objective 4 – to maintain the reliability, security and safety of the distribution network. Without sufficient levels of maintenance, EnergyAustralia cannot achieve this operating expenditure objective. Further, there are a number of obligations – relevant to Objective 2 – which EnergyAustralia would not comply with if it were to fail to adequately maintain the network. The relevant obligations are discussed below.

EnergyAustralia has obligations under its Network Management Plan (Attachment 4.2) to manage its network in a manner that provides reliable supply to customers and protects the safety of electrical workers and the public. These requirements necessitate implementation of an appropriate maintenance regime for network assets.

EnergyAustralia's Occupational Health and Safety (OH&S) and environmental protection obligations are an important input in determining the manner in which maintenance is carried out. EnergyAustralia must provide a work environment that is safe for workers and must manage environmental impacts in accordance with relevant obligations and specific licences. Network maintenance must therefore be undertaken in a safe manner and consistent with OH&S requirements and environmental obligations. Staff must be adequately trained to undertake this work and safe work methods are required to be updated whenever changes occur. EnergyAustralia's OH&S and environmental obligations guide consideration of network risks, particularly in terms of network safety.

The operating expenditure objectives explicitly recognise that expenditure will be required to maintain the reliability, safety and security of the distribution system. Capital investment and maintenance costs cannot be viewed in isolation. A decision to defer or bring forward asset replacement has direct implications for maintenance expenditure.

EnergyAustralia has therefore carefully analysed the inter-relationship between replacement and maintenance expenditure and has developed a mechanism whereby the trade off between the two can be quantified and used as an input to ensure that investment decisions deliver efficient and prudent outcomes as required by the Rules.

Maintenance forecasting approach

Maintenance costs account for approximately 41 percent of EnergyAustralia's total operating costs forecast for the 2009-14 period. This forecast is based on a starting point which itself is derived from leading asset management practices that have been implemented at EnergyAustralia before 2004.

EnergyAustralia uses Failure Modes Effects Criticality Analysis (FMECA) and Reliability Centred Maintenance (RCM) to determine the efficient level and type of maintenance that should be undertaken for an asset base of EnergyAustralia's size, type and age. FMECA and RCM determine effective maintenance practices and identify appropriate maintenance frequencies. EnergyAustralia is a leader in the application of this type of analysis in the electrical distribution industry and has a proven track record in improved maintenance performance and effectiveness.

The FMECA/RCM process considers and assesses each asset for its criticality, the function it performs, the potential causes of its failure, the consequence of the asset failing to perform its function and how the failure of that asset can be managed.

The rationale behind this approach is that the failure characteristics of an asset, in terms of risk and consequence, can be forecast with a reasonably high level of accuracy. As a result of its application, EnergyAustralia has designed maintenance activities around managing these failure characteristics. EnergyAustralia has implemented maintenance standards that are appropriate for an aging network and have proven to be effective in terms of managing risk and prolonging the life of network assets. The maintenance standards and FMECA analysis is incorporated into EnergyAustralia's Technical Maintenance Plan which sets out the periodicity, tolerance[55], and type of maintenance tasks required for each asset.

EnergyAustralia engaged SAHA International to benchmark asset management performance with a particular focus on maintenance. SAHA concluded that EnergyAustralia's maintenance practices were relatively efficient. They found that

"EnergyAustralia meets or exceeds best practice thresholds for asset management practices.…[EnergyAustralia's] current asset management regime ensures that maintenance programs are optimised for both cost and asset performance."[56]

EnergyAustralia's maintenance philosophy is a key driver of maintenance work volumes and therefore costs. EnergyAustralia's maintenance strategy is outlined in our Network Management Plan (Attachment 4.2), our Asset Management Strategy, (Attachment 9.3) and our Maintenance Requirements Analysis Manual (MRAM). The practical outcomes of our asset management philosophy and analysis are represented by the Technical Maintenance Plan. Both the MRAM and the Technical Maintenance Plan are posted on EnergyAustralia's intranet and can be made available to the AER on request.

Maintenance categories

EnergyAustralia undertakes and reports four types of maintenance:

- **Inspection** – all work associated with appraisal and preventative maintenance. This includes condition monitoring;
- **Corrective** – all work associated with correcting defects that have not yet resulted in a "breakdown". Corrective maintenance occurs when assets fail to meet the threshold criteria set to ensure it remains in working order until the next maintenance cycle;
- **Breakdown** – all work associated with equipment that has ceased to perform its designed function (excluding nature induced breakdown); and
- **Nature induced breakdown** – all work associated with equipment that has ceased to perform its designed function due to factors beyond the equipment's design capability. These failures cannot be managed through maintenance activities.

55 Tolerance refers to the window of time that the maintenance regime allows for the inspection task to be completed. For example, an asset may require inspection every three years and have a tolerance of three months either side of this date where the maintenance can take place and still be in accordance with the TMP.

56 Attachment 6.2 Electricity Distribution Business Operational Expenidture Review – SAHA, 2008

9. Operating expenditure forecast methodology (continued)

Reporting maintenance in these categories allows EnergyAustralia to assess the effectiveness of its maintenance program in terms of asset performance over time. Trend analysis identifies whether current levels of maintenance are achieving results. For example, a trend showing a decrease in breakdown maintenance costs demonstrates that the inspection and corrective maintenance is identifying and rectifying potential asset failures before they fail in service. Maintenance strategies come at a cost of inspection, but pay dividends in avoiding failures in service that cause reliability impacts and are expensive to rectify.

Figure 9.4 illustrates the relative contribution of these maintenance categories for EnergyAustralia's overhead feeder network (left) and underground feeder network (right).

The split between preventative, corrective, breakdown and nature induced breakdown maintenance costs varies with asset type. This is a function of asset condition, but is also a function of asset accessibility. EnergyAustralia expends significant efforts in monitoring the condition of underground assets, particularly in the subtransmission network because of their criticality to network performance.[57]

Figure 9.5 shows actual maintenance division operating expenditure compared to EnergyAustralia's forecast costs in 2004 and the projections incorporated in this proposal for the 2009-14 period.

The green line shows the actual results for the 2004-07 period and projections for the remainder of the current period, as well as the forecast for the 2009-14 period.

It can be seen that maintenance costs have increased in real terms over the first three years of the period, but are projected to increase at a slower rates from 2007 onwards. This result is consistent with EnergyAustralia's commitment to IPART to address the backlog of maintenance tasks which were outstanding at the beginning of the 2004-09 period.

As of 2006-07 EnergyAustralia's maintenance is being completed in line with the TMP and therefore represents an appropriate starting point for forecasting maintenance costs in the future.

The projected operating expenditure shows a significant improvement in costs projected for the 2009-14 period compared to the outcomes forecast in 2004 for the same period. This is driven by the impact of the large scale replacement of assets that is incorporated into EnergyAustralia's capital forecast for the 2009-14 period. Figure 9.6 shows how maintenance costs change over time as a result of planned replacements in various asset classes.

Replacement of key assets has the effect of reducing forecast maintenance costs during the period in some asset classes. However, it can be seen that in classes where less replacement is planned (i.e. distribution mains and distribution substations) maintenance costs are forecast to rise to reflect the higher costs of managing an asset base that continues to age. The relationship between age, condition and maintenance costs is described further in the following section.

Top – down approach

Asset condition drives maintenance costs but using RCM approach, preventative maintenance is required for all assets – even those in good condition. Condition, therefore, does not trigger maintenance costs per se as inspection maintenance is triggered by the presence of the asset on the system. Instead, asset condition influences the mix of the type of maintenance undertaken. For example, older assets require more frequent inspections and generally contribute more corrective maintenance tasks to the overall program. To forecast operating costs into the future, EnergyAustralia therefore requires a mechanism to determine the likely condition of assets in future and the consequent mix of maintenance tasks in order to forecast future maintenance costs.

EnergyAustralia has used a top-down approach to forecast its maintenance requirements for the 2009-14 period. This approach is the same approach to forecasting maintenance costs as that used in 2004.

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57 Inspection costs are much cheaper than corrective or breakdown tasks. The split of costs between these categories disguises the significantly higher number of inspection tasks undertaken compared to either corrective or breakdown tasks.

Figure 9.4: Maintenance costs for EnergyAustralia's overhead (left) and underground (right) feeder networks (2004-07 average)

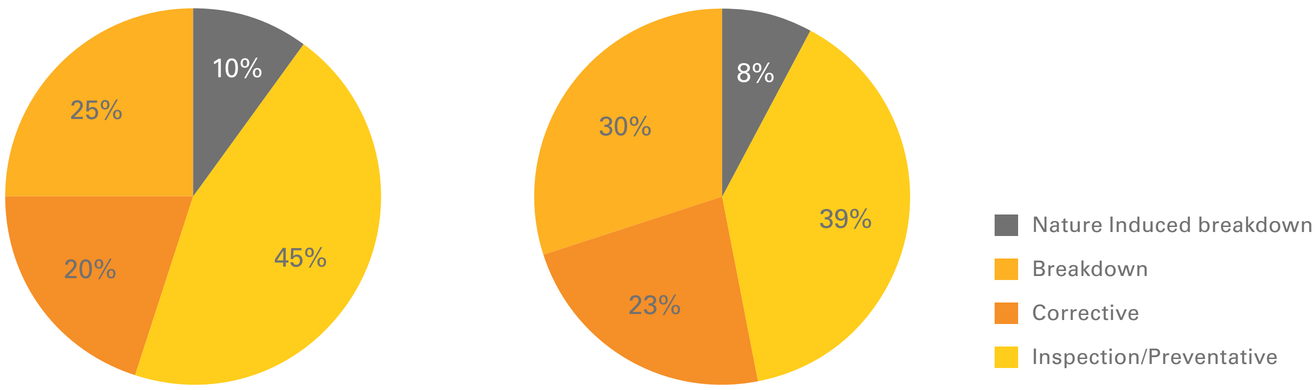


Figure 9.5: Projected maintenance division expenditure totals 2004-14, the regulatory allowance and the forecast provided in 2004 ($m constant)

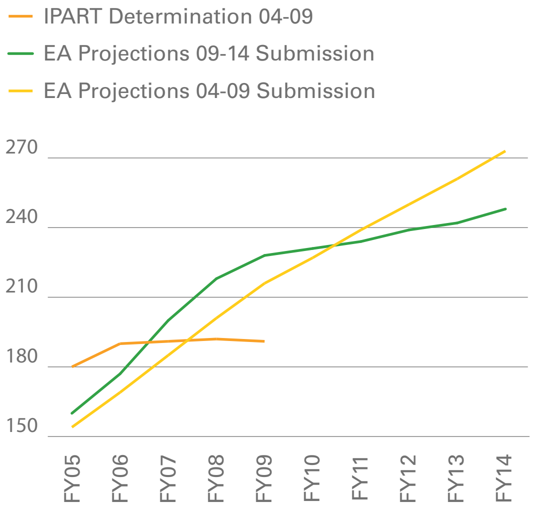
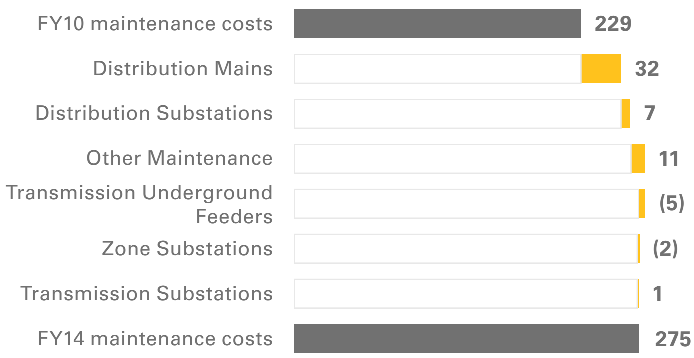


Figure 9.6: Changes in maintenance costs by asset class (FY09 $m real)



This approach uses three steps.

1. the weighted average age of each asset group is calculated as at June 2006 and together with recorded expenditure for 2005-06, is used to create the base asset age curves.
2. The planned asset changes, both removals and installations, as detailed within the various Area and Replacement Plans, are then incorporated into the model to determine the variation to weighted asset age in each year.
3. This new age value is then plotted onto the base age curve to determine the required maintenance expenditure associated with the asset group for a specific year or period.

The methodology uses weighted average age as a proxy for expected asset condition and in so doing, can be used to predict maintenance costs into the future.

Any variation to the timing of delivery of the capital plans will have an impact on the maintenance requirements due to the associated change to the average weighted age.

The new maintenance cost requirement can be recalculated within this model enabling the identification of the capital and operating expenditure impact of each Area and Replacement Plan individually.

Figure 9.7 shows this outcome at a single asset class level. In this example, the costs of maintaining overhead transmission mains continues to increase over time. This is consistent with the replacement plan which does not include large scale replacement in this asset class.

Bottom – up approach

In order to confirm the credibility of the outcomes from the top-down approach, EnergyAustralia has also undertaken a bottom-up assessment of its maintenance requirements. This involved analysis of historic numbers of completed planned inspection tasks and calculation of the associated costs per task. This cost was then compared to the actual recorded costs.

9. Operating expenditure forecast methodology (continued)

In this analysis future planned inspection costs have been adjusted to reflect the investments outlined in the Area and Replacement plans which, when implemented, will result in older assets being replaced with newer technology, which will reduce ongoing total maintenance costs.

The two approaches (top-down and bottom-up) used to forecast maintenance costs have been reconciled to ensure that the program is an accurate reflection of the system's needs into the future.[58]

Implications for forecasting costs

EnergyAustralia has developed a robust forecast of maintenance requirements that directly links to EnergyAustralia's capital investment proposal outlined in Chapter 5. We have applied two methodologies to ensure that at a high level we have projected requirements appropriately, and at a low level, the projections produce relevant real outcomes.

The methodology we have used to calculate the trade-off between capital and operating costs was accepted by the ACCC (now AER), by Wilson Cook, and by PB Associates in 2004 and has again been used in the development of the 2009-14 maintenance cost forecast. This analysis identifies the expected change in costs driven by the changing mix of maintenance workload over time.

Outcomes

EnergyAustralia believes that the forecast of maintenance costs will deliver levels of maintenance appropriate for an aging asset base and will successfully manage the lives of assets where possible and ensure that replacement decisions, when made, are optimal.

EnergyAustralia believes that its maintenance costs reflect the efficient costs of a DNSP operating in similar circumstances with a similarly aged asset base.

9.7 Network support costs

Network support costs are costs related to operation and management of the electrical network, but are not maintenance tasks. These costs are essential to the effective operation of the network and include the cost of the emergency and dispatch functions, costs associated with meter operations including meter reading, operational costs associated with system IT such as GIS, and iAMS, system property expenses (land tax and rates) and apprentice training.

Expenditure in network support is necessary to achieve each of the operating expenditure objectives. Objective 2 specifically recognises a DNSP must be provided with sufficient revenue to meet its obligations. However, the other three objectives recognise that expenditure will also be required to provide outcomes that are not directly driven by obligations.

Table 9.1 gives an indication of the most relevant obligations or objectives and how they link to the relevant cost category.

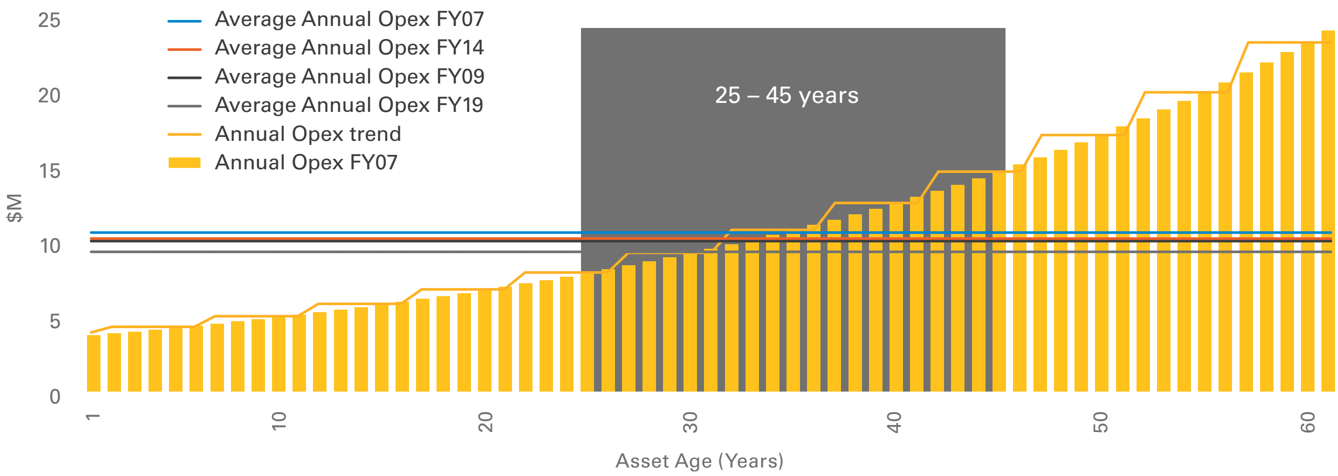
Implications for forecasting costs

Network support costs have been modelled at a granular, activity group level. The drivers of costs in each functional work group have been identified.

EnergyAustralia has identified the percentage of costs in each activity group that is fixed and the portion that varies with external factors such as customer numbers. This analysis enables operating costs at a granular level to link with assumptions made at a global level. It also shows how costs will change with drivers of workload.

58 It should be noted that this reconciliation can only occur in inspection costs as it is impossible to compare number of corrective and breakdown tasks in advance of those tasks occurring.

Figure 9.7: Impact of operating expenditure on timing of capital plans
Illustration: transmission overhead



For example, the cost of EnergyAustralia's call centre varies with the number of calls it receives – higher call volumes require greater numbers of people to answer calls. During normal operations (i.e. normal weather conditions), call volumes are driven by the number of customers connected to EnergyAustralia's network. Whilst there are fixed costs associated with the office and management of the call centre, the variable portion of costs can be linked to the assumed change in customer numbers over the period. Similar analysis of costs and cost drivers has been undertaken for all activities within EnergyAustralia's operating budget.

In addition, all operating costs have been divided into labour, contracted services and materials/other. This split allows EnergyAustralia to separately forecast the future cost movements in these generic costs, and apply appropriate real cost escalation to these elements to ensure that expected real costs movements in the future are accounted for. This is discussed further in Section 10.2.

EnergyAustralia uses the outcomes of this analysis and has quantified the impact of these outcomes against the price and volume escalators described in Section 10.2.

Table 9.1: Summary of network support costs

Network Support Cost Activity Grouping	Function/Activity	Outcome and related objective	Volume and Obligation changes affecting forecasts
Network Planning and Technology	• Network Design • Asset & Investment Management • Demand Management	• These operating activities assist EnergyAustralia in meeting and managing demand across the network (Objective 1) • Some costs associated with these activities are capitalised to investment projects. Operational components include developing systems and processes to ensure future planning and investment is carried out in the most prudent and efficient manner (all four objectives) • Network planning activities ensure that future changes to network do not affect the quality, reliability and security of our service provision (Objective 3) • Relevant obligations include compliance with annual planning report, network management plan and network reliability and performance standards (Objective 2)	• Planning and investment management costs are largely capitalised. However operating components associated with administration, monitoring and reporting are driven by the size of the capital program

9. Operating expenditure forecast methodology (continued)

Network Support Cost Activity Grouping	Function/Activity	Outcome and related objective	Volume and Obligation changes affecting forecasts
Emergency Planning and Response	• Contact centre • Business continuity and disaster planning • Response to customer outages • Emergency work associated with shock and hazards, network incidents • Connection/ Disconnection	• Emergency planning and response activities seek to minimise disruption to the service provided to our customers. Contact centres allow direct contact with customers who may be receiving a disruption to their service (Objective 3) • Appropriate response to customer outages ensures that reliability targets specified in our licence conditions can be maintained (Objective 2) • This activity grouping includes connection and disconnection activities which relate to a customers obligation to connect and our obligations to retailers in cases of disconnection (Objective 2)	• Customer related costs are highly correlated to the number of customers
Customer Connections	• Low voltage network planning • Processing load applications including field and network investigations • Connections management • GIS	• Operating activities associated with customer connections fundamentally driven by obligations to connect customers to the network. (Objective 2) • Low voltage network planning operations also seek to maintain the quality of the network and the service we provide (Objective 2)	Connection costs highly correlated to the number of customers
System IT and Telecommunications	• OMS • iAMS • Network automation • Network Telecommunications • Mobile computing	• Remote control, operational metering and monitoring devices help inform EnergyAustralia as to the drivers of investment across the network (Objective 1, 2 and 4) • Maintenance and support of network asset management, information and performance management systems (Objective 3 and 4) • Timely response to outages assists in us maintaining a quality service delivery (Objective 2 and 3)	Cost to maintain and support Network IT systems is driven by the IT capital program

Network Support Cost Activity Grouping	Function/Activity	Outcome and related objective	Volume and Obligation changes affecting forecasts
Apprentice Program	• Training • Management of apprentice progression and qualification	• A highly skilled workforce is essential to achieving operational expenditure (Objectives 3 and 4) • A proactive program for apprenticeships and training ensures that we have the capability to meet or manage demand and maintain the network through efficient delivery of the capital program. This complements EnergyAustralia's other delivery strategies in respect of its large capital expenditure requirement (Objective 1, 3 and 4)	Driven by network requirements
Insurance and Risk Management	• Licence and National Electricity Rules compliance • Development and monitoring of risk management systems/ internal control framework • Maintain appropriate levels of insurance	• EnergyAustralia prepares a licence and NER compliance database to ensure it maintains compliance with its range of obligations and requirements (Objective 2) • EnergyAustralia also follows prudent risk management practices to ensure a safe, reliable and secure delivery of services (Objective 3) • EnergyAustralia prudently manages some risk through insurance (Worker's compensation, property and general insurance) (Objective 3)	Driven by assessed risk associated with insured and self-insured events

System Property	• Land taxes and rates
	• Property maintenance
		• Land ownership and management is inherent in achieving all expenditure objectives in particular 1, 3 and 4. Consequently EnergyAustralia must forecast expenditure in relation to:
		  • Land development approvals
		  • Building upgrades
		  • Substation fences
			Land taxes and rates driven by increase in system property holdings.

Metering	• Meter reading • Meter services • AMI trials and technology • Meter maintenance	• Metering operations ensure that costs of providing the services are allocated to customers (Objective 3) • Technological advances mean that metering is also fulfilling a secondary purpose of meeting and managing demand (Objective 1) • Expenditure includes oversight of a suite of metering obligations contained in the National Electricity Rules and related instruments (these relate to installation, testing, maintenance, security) (Objective 2) • National Meterology Procedures (Objective 2)	Meter reading and maintenance costs driven by the number of meters in service

9. Operating expenditure forecast methodology (continued)

Outcomes

Expenditure to support the network enables EnergyAustralia to successfully meet its obligations to connect and manage its interface with customers, and also enables EnergyAustralia to plan for future network incidents and their recovery. Network support costs are critically important in regard to training staff to maintain and operate the system for future generations. Network support expenditure is consistent with the operating expenditure objectives.

9.8 Business support costs

Business support costs are those that relate to normal operation of a business such as Executive Management and Board costs, billing functions, operation of standard back office IT applications, and the regulation and pricing functions. Business support costs are costs faced by any non-network business in Australia.

Obligations

There are a wide range of obligations and expenditure objectives that drive business support costs. Table 9.2 gives an indication of those that are most relevant and demonstrates their relationship to the various cost categories.

EnergyAustralia's business support costs are essential to the provision of Standard Control Services.

Business support costs account for approximately 20 percent of EnergyAustralia's total operating costs in the 2009-14 period.

Like network support costs, business support costs have been modelled at a granular, activity group level. The same methodology has been used to identify the drivers of costs in each functional work group and the percentage of costs in each cost group that is fixed and the portion that varies with external factors.

A similar process of rolling forward costs has been used to forecast business support costs for the 2009-14 period, with adjustments for step change, workload and pricing factors.

Implications on forecasting costs

This forecast does not include costs of possible separation of EnergyAustralia's Retail and Network businesses. The implementation of a government decision to separate the retail and distribution activities of the organisation would result in a loss of synergies that the network business has enjoyed to date with its retail business and will therefore result in an increase in the costs of network as a stand alone business.

EnergyAustralia proposes that this cost be included as a specific pass through event. This is discussed further in Section 15.7.

Table 9.2: Summary of business support costs

Business Support Cost Activity	Function	Outcome and Related Objective	Volume and Obligation indicators affecting forecasts
Customer services	• Billing • Debtor management • Customer relations – EWON • Customer field support • Customer service centres	Customer service costs relate to the maintenance of the quality of Standard Control Services we provide to our customers. It is related to obligations surrounding billing, customer dispute resolution procedures, connections management and customer service standards (Objective 4)	Customer service costs highly correlated with the number of customers
Non-system IT and infrastructure	• Business support • Financial and related systems • Database & system support/help desk • License fees large component of costs	Operating activity largely driven by capital investment in IT systems which are used to ensure the quality and reliability of the system, meet or manage demand and better inform the business as to how to manage the network business (Objectives 1, 3, and 4)	IT infrastructure and support costs highly correlated with the number of PCs in operation
Non-System Property and Admin	• Land tax, rent and rates • Purchase of electricity • Water • Maintenance	These costs are necessary costs in accommodating staff to undertake network and operational functions in achieving operating expenditure objectives (Objective 4)	Business support property maintenances costs driven by the condition of office and depot premises
Corporate and Divisional Support	• Executive • Finance and Administration • Corporate HR • Media and internal communications • Legal	Corporate and executive functions are vital to a large business in order to maintain quality service to customers (Objective 4)	Base expenditure mostly constant with incremental cost impacts driven by specific initiatives
Regulation and Compliance	• Regulatory policy, pricing and preparation for 5 year review • Technical publications and printing • Internal Audit	Regulation and compliance activities inform the business of regulatory obligations and requirements. They also are a necessary cost in achieving the requirements of Chapter 6 of the National Electricity Rules (Objectives 2 and 4)	Regulatory submission costs driven by the five-year regulatory control cycle

9. Operating expenditure forecast methodology (continued)

Outcomes

The expenditure on business support will enable EnergyAustralia to successfully manage the interface with its customers, comply with regulatory obligations and to effectively operate sophisticated IT systems to deliver and report business and network outcomes to internal and external stakeholders. Therefore, business support expenditure is consistent with the operating expenditure objectives.

9.9 Conclusion

This chapter provided an overview of EnergyAustralia's approach to develop into the operating expenditure forecasts for its network, to achieve the objectives set out in the Rules.

The purpose of this chapter has been to:

- outline the required operating expenditure for EnergyAustralia to achieve the operating expenditure objectives over the period; and
- demonstrate the consistency between EnergyAustralia's obligations and the operating expenditure objectives at each category of cost.

EnergyAustralia's approach to forecasting the maintenance requirements of its network assets represents industry best practice. This methodology is founded on a detailed knowledge of equipment condition and assessment of the consequences of failure.

For other categories of operating cost, EnergyAustralia undertakes the forecasting process at a granular level by looking at individual cost activities, understanding their key price and volume drivers and forecasting operating expenditure based on the forecast movement of these drivers over the period. A description of the processes used for each category of operating cost has been provided.

10. Operating expenditure program

The purpose of this chapter is to:

- summarise the process for establishing the starting point for operating expenditure forecasts;
- explain the interaction of starting point expenditure, cost activities, cost categories and forecasts; and
- describe, for each cost category the main factors (volume or price escalators and step changes in obligation) which influence expenditure forecasts over the period.

10.1 Starting point for establishing operating expenditure forecasts

In the previous section EnergyAustralia outlines how operating expenditure is driven directly and indirectly by obligations, and how expenditure to meet these obligations delivers outcomes that achieve the operating expenditure objectives.

The next section outlines how and why EnergyAustralia has established a starting point for operating costs that is the basis for the operating expenditure forecast contained within this proposal.

10.1.1 Why a starting point for operating expenditure forecasts?

Operating expenditure differs from capital expenditure in that it typically comprises recurrent annual costs. In contrast, capital expenditure is time specific, lumpy, and driven by particular circumstances that trigger investments.

EnergyAustralia has used the 2006-07 operating costs as a starting point for future projections of operating costs. EnergyAustralia is able to demonstrate that this year represents a suitable and efficient starting point and, through detailed forecasting methodology, is able to deliver a forecast with considerable granularity and a high degree of forecast accuracy.

EnergyAustralia has used the most recent, complete and audited year of financial accounts (actual expenditure for 2006-07) as the basis for forecasting operating expenditure in the 2009-14 period. Not only is 2006-07 the most recent full year of accounts, it is the first year during which backlogs of preventative maintenance have been fully completed, and is also the first complete year that reflects the impact of EnergyAustralia's successful pass-through claim in 2005.

EnergyAustralia has operated under an ex-ante incentive framework for operating costs during the past two regulatory periods and understands the framework which penalises businesses that spend above their operating allowance.

EnergyAustralia has financial incentives to spend less than what the regulators allowed for operating expenditure during the 2004-09 period. During this period EnergyAustralia has taken steps to minimise the variance between actual costs and the allowance to the extent possible while still delivering outcomes in line with the operating expenditure objectives and our obligations. The actual operating costs in 2006-07 therefore reflect EnergyAustralia's efficient operating costs during that year.

The current five year control period should also be considered in setting expenditure for the next control period as the 2007-08 expenditure can be forecast with a high degree of certainty and the 2008-09 budget has been approved.

10.1.2 The starting point compared to the allowance

EnergyAustralia's 2006-07 operating costs are higher than the allowance granted to EnergyAustralia by IPART and ACCC. As a result, EnergyAustralia has lost value (i.e. the business will never be compensated for operating expenditure that is higher than the allowance) despite the fact that the costs are legitimate and reflect real network needs.

These losses have been absorbed by EnergyAustralia in the 2004-09 period because the additional costs were necessary for EnergyAustralia to operate its network business in a manner that meets its obligations and achieves the operating expenditure objectives.

The variance between the regulatory allowances and the actual 2006-07 expenditure (discussed in the following sections) is largely represented by changes in cost inputs and incidental increases in operating costs to support a higher than forecast capital program.

The most recent observation of cost inputs and operating expenditure requirements logically represents the most likely indicator of operating expenditure forecasts.

The inability of EnergyAustralia to recoup the costs associated with meeting the objectives in the current period is a timely reminder that incentive frameworks must firstly begin with forecasts that reasonably cater for a range of cost and volume outcomes over the period.

10. Operating cost forecast methodology (continued)

NERA notes that

"setting expenditure benchmarks by reference to 'perfect' efficiency runs the risk of establishing tariffs that are below the lowest sustainable cost of delivering the service that is practically achievable for all firms. Tariffs set by reference to 'perfectly efficient' costs risk undermining service providers' incentives to undertake efficient investment and may therefore be detrimental to dynamic efficiency and so to the long-term interests of consumers."[59].

The actual costs incurred by EnergyAustralia in 2006-07 in meeting the operating expenditure objectives represents an appropriate starting point for each category of operating costs.

10.1.3 Forecast operating expenditure assumed by IPART and ACCC in 2004

In 2004, in relation to the distribution network, IPART approved $1,555 million in operating expenditure over the 2004-09 period. This allowance was $59 million lower than that sought by EnergyAustralia. This allowance was considered by IPART at the time to represent "efficient operating and maintenance expenditure"[60].

In 2005, in relation to the transmission network, the ACCC approved $134 million in operating expenditure over the 2004-09 period. This allowance was $9 million lower than that sought by EnergyAustralia.

10.1.4 Cost pass through

As a result of the new DRP licence conditions, IPART approved a pass through of the incremental expenditure. This approval increased the distribution operating expenditure by $64 million.[61] The pass through resulted in an adjustment in revenue allowance for the operating expenditure of $15 million for 2006-07, increasing to $25 million in 2008-9 (nominal).

The total operating expenditure allowance approved for the distribution, distribution pass through and transmission determinations is summarised in Table 10.1.

Table 10.1 – Allowed operating expenditure ($m nominal actual CPI adjusted)

	FY05	FY06	FY07	FY08	FY09
Distribution	288	302	313	322	330
Distribution pass-through	0	4	15	20	25
Transmission	25	25	27	28	30
Total Allowance	312	331	354	371	384

10.1.5 Factors that drive variances in 2006-07 and impact forecasts

This section summarises the key differences between forecast operating expenditure assumed by IPART and ACCC (adjusted for pass through costs) and the actual operating expenditure in 2006-07.

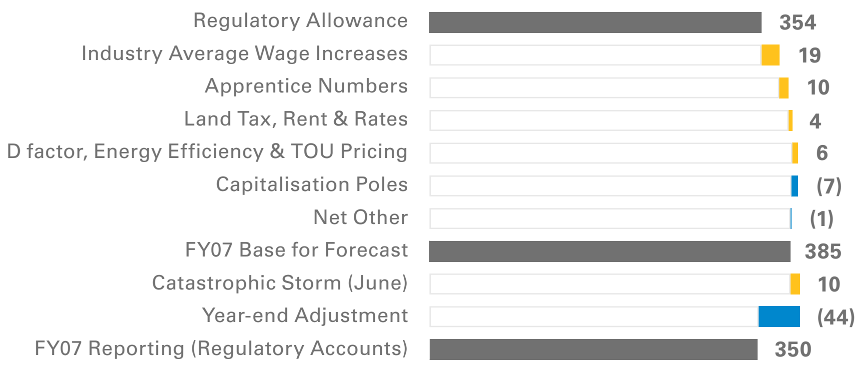
Excluding one off and year end adjustments the operating expenditure for 2006-07 was $385 million, which was used as the base to forecast operating expenditure for the 2009-14 regulatory period. Figure 10.1 shows major variances between the allowance and the actual reported results, both before and after one off and year end adjustments are taken into account (see Section 10.1.6).

59 NERA Economic Consulting economic interpretation of clauses 6.5.6 and 6.5.7 of the NER

60 IPART final determination, p55.

61 IPART, statement of reasons for decision, 4 May 2006

Figure 10.1: Explanation of variances in FY07 results ($m nominal)



Labour cost movements (industry average wage increases)

EnergyAustralia has faced higher rates of growth in labour costs than was forecast in the 2004 determination. Over half ($19 million) of the 2006-07 variance between actual expenditure and the allowance is as a result of compounding increases in unit labour costs since 2003-04.

Figure 10.2 shows the rate of increase of real labour costs (within the Australian economy) in respect of:

- the electricity, gas and water sectors;
- the construction sector; and
- average wages.

It is clear that wages, which drive the main portion of operating costs, have increased at a higher rate than general inflation.

Since 2004, wages in the electricity, gas and water sector have increased by at least two percent above CPI. This increases to over four percent above CPI in 2007.

This labour cost wedge has been the largest single factor driving variances between allowed and actual expenditure since 2004 and is forecast to continue to increase at a rate above CPI for the rest of the regulatory control period. Put simply, the IPART determination did not reflect the true cost of labour experienced by the industry in the current regulatory control period. It should have been reasonably foreseeable by IPART that wages would escalate well beyond CPI.

Apprentices

EnergyAustralia increased the annual intake of apprentices in the current regulatory control period as a result of analysis of workplace age, expected staff retirements and the increase in capital expenditure requirements. The extent of the apprentice program was not forecast at the time the 2004 determination was made and therefore not included in EnergyAustralia's underlying operating costs[61].

Some compensation for an increase in apprentice numbers was incorporated in the pass-through application sought by EnergyAustralia in response to the introduction of the DRP licence conditions. However, approximately $10 million of variance remains in the annual cost of the 550 apprentice strong program and the annual allowance for apprentice training.

The variance attributable to apprentices can therefore be regarded as efficient as it represents the actual cost of training new staff, ensuring that a sustainable workforce is available now and in future periods to achieve the operating expenditure objectives.

Property costs (land tax, rent and rates)

There was a variance above budget ($4 million) for property costs (land tax, rates and rent). This non-discretionary expenditure largely related to the increase in system land holdings to accommodate network expansion and the value of those land holdings increasing over time.

The trend of increasing costs associated with land is likely to continue as the network expands. Both volume escalation (increase in the portfolio of land) and price escalation (increase in the value of land) will increase the impost of rates and taxes that will be reflected in increasing real costs driven by property over the 2009-14 regulatory control period.

Demand management, energy efficiency and pricing initiatives

There was a slight variance above budget ($6 million) for demand management and ToU pricing initiatives which are functions directly aimed at meeting and managing expected demand on the network consistent with EnergyAustralia's obligations and objectives.

10. Operating expenditure program (continued)

EnergyAustralia is a strong advocate of demand management and recognises that demand management does not occur without proactive business investment. EnergyAustralia considers and makes provision for non-network alternatives as part of its forecasting, planning and capital governance processes.

Investment in non-network and other demand management initiatives above the regulatory allowance has been undertaken on the basis that it will contribute to EnergyAustralia's practical experience of implementing demand management programs. This will enable EnergyAustralia to implement innovative solutions in the future.

In the 2009-14 period, EnergyAustralia has successfully sought a Demand Management Innovation Allowance which will take account of this type of demand management activity and investment and ensure that, unlike the 2004-09 period, EnergyAustralia may be compensated for future demand management and pricing initiatives. Nevertheless, EnergyAustralia argues that current incentive arrangements fall short of what would be a realistic allowance for demand management initiatives (both network and non-network) in the context of a multi-billion dollar investment program. EnergyAustralia's argument for a better application of the demand management incentive scheme is found in Section 14.2.

Change in capitalisation policy (poles)

EnergyAustralia's pole replacement program was reviewed post 2004 to ensure that the program was effectively mitigating risks of pole failure. The proximity of poles to customers and the number of poles within EnergyAustralia's network (approx 500,000 poles) makes pole failure a particularly high risk for the business. Not only are the consequences of pole failure severe in terms of public safety, a systemic failure could have wide spread implications for reliability across the network.

As a consequence of EnergyAustralia's review, pole replacement activity increased significantly during the 2004-09 period. In moving towards a program of pole replacement over the period, EnergyAustralia changed the capitalisation policy to include pole replacement.

The change in accounting policy for pole replacement and the subsequent capitalisation of pole replacement during the 2004-09 removed $7 million per annum from operating costs with a consequent increase in capital expenditure.

10.1.6 One off year end adjustments

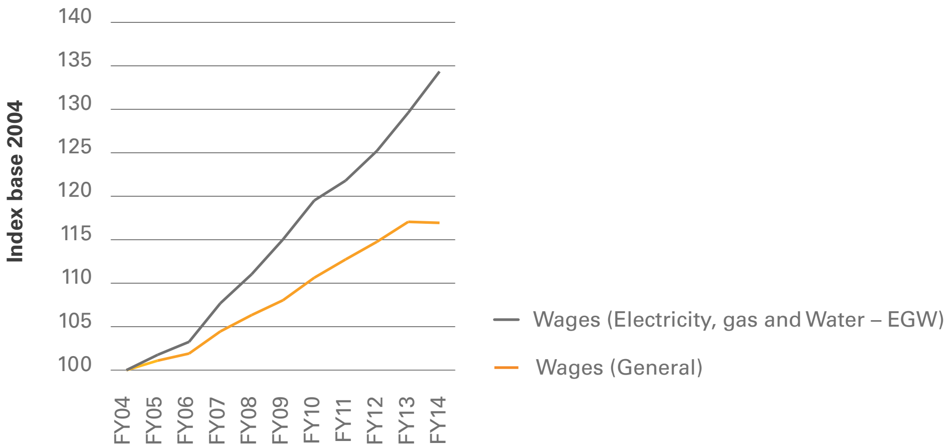
To ensure that the 2006-07 operating costs are a true reflection of ongoing costs, EnergyAustralia has taken out the impact of year end adjustments that were made to the financial accounts which did not represent recurrent costs.

In 2006-07 there was a one-off credit adjustment of $6 million to align employee retirement and labour on-cost provisions with expected future obligations. There was also a one-off $38 million credit recognised in relation to Energy Industry Superannuation Scheme (EISS) defined benefit fund balances based on actuarial assessment of future obligations. The annual superannuation adjustments fluctuate based on the earnings performance of the fund and are not representative of ongoing superannuation costs. Together these resulted in a year end adjustment of $44 million.

EnergyAustralia also faced significant additional expenditure as a result of the 2007 June long weekend storms that resulted in wide spread flooding and network damage in the Newcastle and Central Coast regions. A significant portion of expenditure resulting from the storm was capitalised where it resulted in the replacement of distribution mains. However, the storm contributed $10 million to increased operating costs which would not normally be incorporated into future budgets.

In summary, one-off expenditure items ($34 million) in the end year result are excluded from the starting point calculation.

Figure 10.2: Real labour cost trends 2003-2014[62]



10.1.7 Starting point for calculating forecast operating expenditure

It must be recognised that although EnergyAustralia has overspent its operating expenditure allowance this has been necessary to meet the preceding factors, many of which were not apparent at the time of the 2004-09 regulatory decisions. There was a very substantial incentive to reduce operating expenditure costs built into both the IPART and ACCC regulatory frameworks, in that each dollar of operating expenditure that was over-spent lowered shareholder returns. EnergyAustralia has therefore had a strong incentive to minimise operating expenditure.

EnergyAustralia believes that the actual 2006-07 operating cost (net of year end adjustments) of $385 million represents an appropriate starting point for the development of future operating expenditure forecasts. The reconciliation of costs back to the IPART and ACCC allowances, and the link to underlying operating obligations and objectives demonstrates why the 2006-07 actual expenditure is justified and why it is an appropriate basis for establishing operating cost forecasts for the 2009-14 period.

EnergyAustralia has used the starting point and the escalation assumptions to estimate the operating costs for the remainder of this regulatory control period.

The next section outlines the variance between forecast and estimated operating expenditure using this approach.

10.1.8 Impact of variance in 2008-09

The variance identified between allowance and actual operating expenditure in 2006-07 is exacerbated in 2008-09. Figure 10.3 shows how variations in the forecast at the start of the period are compounded during the period. Relatively minor variations at the start of the period become significantly larger as the period progresses. It also demonstrates the importance of accurately forecasting the starting point and the rate at which costs change over time. This is particularly true for the forecast of operating costs in the 2009-14 period as outcomes compared to allowances will have implications for future periods through the efficiency benefit sharing mechanism.

The variance of actual and allowed operating costs in 2008-09 can be explained by the variance in 2006-07, the application of price and volume escalators to the 2006-07 actual costs, and the impact of new factors in the 2008-09 starting point (for example IT capital expenditure and network automation).

Continuing factors from the FY07 starting point

The largest variance is associated with labour costs which contributed $19 million of the variance in 2006-07, and in 2008-09 is forecast to contribute $38 million. This reflects the impact of compounding labour indexation. It should be noted that the indexation applied relates to industry wide electricity, gas and water sector wages, which in general are below the levels paid by firms situated in Sydney's CBD. In general, it can be expected that given EnergyAustralia's industrial situation our wage rates would change at a rate at the high end of the range rather than the average. Therefore, inherent in the use of this industry wide average rate, is a built in efficiency measure.

Another large variation relates to land tax, rent and rates which also compounds over time. In 2006-07 the variance from the allowance was $4 million, however this item increases to $16 million by 2008-09 and is driven by both system and non-system land holdings.

D factor, energy efficiency and ToU metering variances at the end of the current period have contributed $9 million to the variation between actual and allowed expenditure. This is a key area of continued expenditure in the next period due to the move to cost reflective pricing.

10. Operating expenditure program (continued)

New factors in the 2008-09 starting point
Operating expenditure undertaken to automate the distribution network is also a major contributor to variation in forecast operating expenditures in 2008-09. The distribution network automation program was not foreseen at the time the operating expenditure allowance was granted by IPART but has become an important part of EnergyAustralia's reliability strategy since the introduction of the DRP licence conditions. The capital expenditure to deliver distribution network automation is accompanied by operating costs that represent legitimate costs of delivering improved reliability outcomes for customers by 2008-09. It is considered that this program is not discretionary in delivery of the DRP conditions.

Increased workload is also a significant factor in the area of system maintenance. Workload escalators applied to the 2006-07 starting point contribute $17 million of additional operating expenditure in 2008-09. This is driven by the addition of new assets to the system as well as a delay in replacement of poorly performing assets in the later part of the current period.

10.2 EnergyAustralia's operating cost model

EnergyAustralia has built a sophisticated operating cost model to forecast operating expenditure over the 2009-14 period.

The model has been used to derive the forecast operating costs EnergyAustralia requires to achieve the operating expenditure objectives. The model has also been built to track operational expenditure performance against the forecast. This will allow EnergyAustralia to evaluate the future performance against forecasts and will help identify how and why costs may change over time. This is particularly important in the context of the efficiency benefit sharing mechanism which effectively penalises businesses that overspend their allowances.

The model enables operating activities to be mapped to cost centres and in so doing, allows high level drivers of costs to be quantified in terms of their impact on costs over time.

10.2.1 Using the model to quantify the impact of escalators and step changes on cost categories

EnergyAustralia has started with the 2006-07 actual operating costs as the basis for its forecast. These costs have been examined to establish how they are likely to change over time taking account of factors that drive workload, input costs and step changes in activities that may result from external factors such as the introduction of a new obligation or business function (ie an assessment has been made of the fixed and variable component at activity levels). These escalators are applied to the variable portion of each activity cost. The following section discusses how this step is undertaken.

10.2.2 Step changes (function changes)

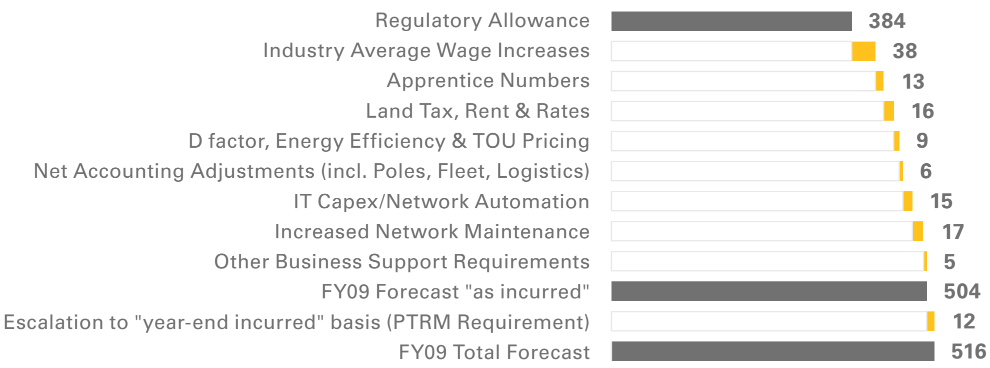
Step changes recognise incremental movements in costs which are expected to occur in changes to the efficient base cost of a particular activity. Costs changes can be both positive or negative and will occur where the function of an activity changes from the base year to the next (i.e. is broadened or curtailed).

For example:

- an increase in IT operating costs can be a consequence of acquiring a new IT system, such as EnergyAustralia's new Integrated Asset Management System (iAMS). Such cost increases can be driven by licensing fees, support costs and increased server box maintenance; and
- operational costs relating to property increase as land is added to EnergyAustralia's land portfolio driven by new substations. As the land 'footprint' grows there are impacts on property taxes, municipal rates, water rates and maintenance.

EnergyAustralia has investigated whether any step changes will occur prior to or during the 2009-14 and has included the costs that result from these changes.

Figure 10.3: Variance in operating expenditures compared to the allowance in FY09 ($m nominal)



Changes to obligations

The new national regulatory framework for distribution and transmission service providers delivers a business environment with greater certainty than the previous regime. However, the codified framework places a greater onus on the business to provide appropriately detailed information for the review. There are substantial penalties for a business that does not provide this information.

The change to the framework together with a general maturing of the regulatory review process has driven significant investment in information development and financial modelling. EnergyAustralia has forecast that the cost of the 2009 review process is approximately $3 million higher than the normal regulatory costs borne by the business on a daily basis. EnergyAustralia has therefore included a five yearly peak in regulatory spending to cater for additional costs.

Demand management

Demand management is generally used to defer capital investment. In 2004, it was thought that the costs of DM would be capitalised and therefore returned to the business over the life of the asset.

Experience during the 2004-09 period has revealed that in general, demand management costs are expended on generator lease fees, payments to customers for interruptible load, Compact Fluorescent Light (CFL) give-away campaigns and power factor correction subsidies, expenditure which is expensed rather than capitalised. EnergyAustralia has therefore included a provision to cover the expected costs of DM in its operating cost forecast.

10.2.3 Workload escalators (volume changes)

Workload drivers are factors which directly impact the volume of work (or number of tasks) which needs to take place. EnergyAustralia has identified workload drivers for each cost activity to ensure the volume change in a particular activity volume is captured in the forecast.

Workload escalation is only applied to the variable element of costs. It allows expected growth in the quantum of actual tasks performed to be incorporated in the forecast.

Capital program

The most significant influence of operating costs during the 2009-14 period is the proposed capital investment program. The program has both a negative and positive impact on operating. Asset replacement has a downward influence on maintenance costs where the volume of assets replaced has a marked impact on the weighted average age of the asset class. However, where the impact of replacement is not sufficient to prevent the weighted average age of the asset class from increasing, maintenance costs will continue to move up rather than down.

10.2.4 Price escalation (price changes)

Price escalation factors allow expected real increases in the costs of tasks to be incorporated. Price escalators are applied to both fixed and variable elements of an activity cost. Price escalation factors consist of:

- CPI;
- labour indexation; and
- contracted services indexation.

Real cost escalation (CPI)

Real cost escalation refers to the change in underlying costs even when normal inflation (CPI) is removed.

Historically, the regulatory framework has assumed that CPI is an appropriate proxy for the changes in costs faced by distribution network providers. However, there is ample evidence that shows the significant divergence between the CPI and the rate at which costs increase for distribution or transmission businesses.

The AER's revenue model uses a forecast for inflation (CPI) at the time the determination is made, and allows this forecast to be substituted with actual inflation during the period when calculating annual revenues.

10. Operating expenditure program (continued)

The model does not allow real cost movements relative to CPI to be represented in the model. Instead, in recent reviews, businesses have incorporated an estimate of the wedge between the rate distributors costs are increasing and the CPI. While this methodology helps mitigate the risk of real cost escalation, neither the framework, nor the model allow for the forecast of the real cost wedge to be calculated ex-post and substituted into the revenue calculation. As a result, businesses still bear the risk that their regulatory allowance will be eroded to the extent that the forecast of real cost inflation is different to actual.

EnergyAustralia experienced an erosion of value of its regulatory allowances as a result of real costs increasing at a higher rate than inflation during the 2004-09 period.

To mitigate this risk in the 2009-14 period, a forecast of real cost escalation has been added to the capital and operating costs included in this proposal. The indexation has been applied to ensure that, as far as possible, the forecast costs reflect real future costs. In addition, EnergyAustralia is seeking a pass-through of costs where actual real cost inflation varies compared to that incorporated in the forecast and the impact to the business meets a threshold.

EnergyAustralia engaged CEG to develop a methodology whereby real cost escalation can be forecast for the 2009-14 period. CEG's methodology and derivation of results is included in its report (Attachment 5.15).

Cost escalators

The escalation factors for labour and other cost movements recommended by CEG are summarised in Table 10.2

Table 10.2: Escalation factors

	FY10	FY11	FY12	FY13	FY14
Real rates (%)					
Copper	-6.30	-4.20	-2.80	-3.10	-3.10
Aluminium	-0.50	-0.20	0.30	0.00	0.00
Crude Oil	-3.80	-1.30	-0.50	-2.00	-0.90
Steel	0.30	0.20	0.20	0.20	0.20
EGW NSW Wages	3.90	1.90	2.80	3.50	3.70
Wages General	2.40	1.90	1.80	2.00	2.00
Construction costs	0.90	0.70	1.10	1.90	2.60
Producer's margin	6.10	7.60	0.00	0.00	0.00
Land & easements	4.10	4.10	4.10	4.10	4.10

Real labour costs in the electricity, gas and water sector are expected to increase at an average rate of 3.2 percent above the rate of forecast inflation. Given labour is the major component of operating costs, it is essential that adequate escalation is applied in order to maintain the underlying value of the forecast.

It should be noted that the labour escalation rates used by CEG and consequently EnergyAustralia are based on industry forecasts by the ABS and other professional forecasting bodies. These forecasts do not specifically link to EnergyAustralia's labour costs which may increase at a faster rate than industry forecasts as the business encourages workers to continue to work in Sydney where costs of living are highest. EnergyAustralia believes that the cost increases forecast for labour are at the low end when applied to its workforce, particularly given our industrial situation.

Cost escalators have been derived for materials and contracted services. Unlike labour, the cost escalators are a composite index of several indicators weighted by their contribution to cost.

EnergyAustralia believes that the inclusion of real cost escalation into the forecast of costs is critical to ensure that the forecast represents a realistic expectation of cost inputs. A failure to take account of these factors will destroy the purchasing power of the operating expenditure allowance and undermine EnergyAustralia's ability to meet the operating expenditure objectives.

10.3 Summary of forecast costs by category

10.3.1 Maintenance costs

EnergyAustralia's maintenance cost forecast for the five year period 2009-14 is shown below. This forecast is directly linked to the capital proposal and assumes that all works forecast are delivered within the period.

The forecast is a function of existing assets and their condition and ongoing condition based maintenance for the future network configuration.

Table 10.3: Maintenance costs (FY09 $m real)

	FY10	FY11	FY12	FY13	FY14
Fixed	27	28	29	30	32
Variable	202	208	219	230	243
Total	229	236	248	260	275

Figure 10.4: Factors that contribute to changes in maintenance cost over time

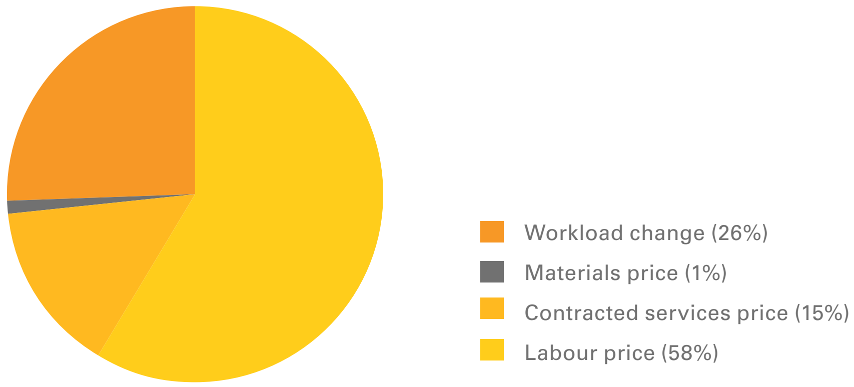


Figure 10.4 highlights the factors that are driving maintenance costs over time. This figure has been derived from the operating cost forecast model by removing price escalators and volume escalators sequentially to identify the contribution of each factor to changes in cost during the 2009-14 period compared to the base year.

The forecast change in labour costs to 2014 contributes 58 percent of the increase in maintenance costs compared to the base year. This is consistent with the shortage of skilled workers currently available in the Australian labour market, and the electricity, gas and water sectors in particular.

Workload change is also a significant contributor of additional costs and contributes 26 percent of the total increase in maintenance costs compared to the base year. This is due to both more assets being added to the system, but is predominantly due to an increase in tasks associated with corrective and breakdown maintenance as the weighted average age of asset classes increases. It is worth noting that the workload change is the net outcome after forecast decreases in maintenance expenditure in the zone substations, transmission substations and transmission mains categories as a result of significant replacement works.

10.3.2 Network support costs

EnergyAustralia's network support costs for the five year period from 2009-14 is forecast as follows

Table 10.4: Network support (FY09 $m real)

	FY10	FY11	FY12	FY13	FY14
Fixed	74	77	76	77	78
Variable	139	144	150	156	159
Total	213	221	226	233	237

This forecast is driven largely by labour cost increases, workload increases associated with an increase in numbers of assets, and increased customer numbers. Figure 10.5 shows the factors that drive changes to network support costs over time.

Changes in network support costs are driven by a variety of factors during the period. The forecast change in labour price is again the largest contributor of overall cost change when compared to the base year. The increase in labour prices also contributes to increased costs of contract services. However, the labour cost inputs incorporated in contract services are labour rates for unskilled labour and labour in the building and construction sector rather than the electricity, gas and water sectors.

It is worth noting that capital expenditure on IT and property also drives changes to network support costs. This inter-relationship was not captured in the 2004 forecast of operating costs and can be seen to be significant over time, particularly in the final years of the current regulatory period.

10.3.3 Business support costs

EnergyAustralia's business support costs for the five year period from 2009-14 is forecast as follows.

Table 10.5: Business support (FY09 $m real)

	FY10	FY11	FY12	FY13	FY14
Fixed	74	74	75	76	77
Variable	42	43	44	48	43
Total	116	117	119	123	120

Figure 10.6 shows the factors that drive changes to business support costs over time. Labour prices are again the most significant influence on the cost forecast compared to the base year. It is worth noting that the largest cost drivers of changes to network support costs are also significant drivers of change in business support costs.

Another key driver of business support costs is the substantial impact of property maintenance costs (14 percent) compared to the base year. Higher maintenance cost in this area are consistent with an aging portfolio of property assets which require renewal during the next decade.

10. Operating expenditure program (continued)

10.4 Additional costs to be considered

10.4.1 Self-insured and uninsured risks

In the context of insurance there are three categories of cost that need to be considered.

- insurance sought externally – for significant risks such as bushfires;
- self-insurance provided by EnergyAustralia – for risks that EnergyAustralia can credibly insure such as workers compensation; and
- uninsured risks – for risks that EnergyAustralia has either decided are not cost effective to insure or is unable to self-insure, such as the residual risks associated with insurance policy deductibles.

These three types of risks are business risks that all result in a legitimate and direct cost on EnergyAustralia. The cost of insured risks is the insurance premium paid to the broker. In relation to self-insured risks, the cost is the cost of claims made against that provision. In relation to uninsured risks, the cost is that which results from the risk, should such an event occur.

EnergyAustralia proposes that these legitimate costs should be recouped through the regulatory process. Insurance premiums are typically embedded in the operating expenditure base year and are thus not double counted here. The self insured and uninsured risks have been reported and quantified by SAHA International in Attachment 10.1.

The basic premise is that of "expected cost". That is, for the uninsured risks SAHA has calculated, using either EnergyAustralia's historical cost data or data sourced independently, the expected annual cost of each risk.

EnergyAustralia considers self-insurance to be a necessary expenditure to achieve the operating expenditure objectives, in particular Objective 3 which provides for businesses to be able to maintain the quality, reliability and security of supply of Standard Control Services. EnergyAustralia believes that risk management is part of the necessary steps a prudent operator would take in their provision of Standard Control Services.

10.4.2 Debt and equity raising costs

EnergyAustralia has a significant program of capital investment forecast in the 2009-14 period. This program will require EnergyAustralia to source large levels of debt and equity financing over the period to generate cash flow to facilitate the program.

Recent regulatory decisions made by the AER consistently apply a policy of allowing businesses to recover debt and equity raising costs. EnergyAustralia notes these decisions have been made using an assumed debt/equity ratio of 60:40.

EnergyAustralia believes that the debt raising costs should reflect actual debt levels but has decided to defer this debate to the 2009 review of the WACC parameters.

EnergyAustralia engaged CEG to provide a methodology for establishing the costs of raising debt and equity (Attachment 8.2).

Based on the CEG recommendation, EnergyAustralia has incorporated an allowance of 12.5bppa (basis points per annum) for direct debt raising costs plus a three bppa allowance for indirect costs.

CEG has estimated the cost of equity raising to be $230 million over the 2009-14 period. The methodology for determining how much capital has to be raised follows ACG's methodology submitted on behalf of ElectraNet[62]. If recovered during the 5 year regulatory period this $230 million allowance would result in the recovery of around $55 million per annum.

However EnergyAustralia has adopted the approach of amortising the cost of raising equity in perpetuity starting in the year in which the cost will be incurred. Under this approach real operating costs are increased by $230 million times real WACC each year after the capital was raised. Based on an assumption of the capital being raised at the end of the second year and a real WACC of 7.04 percent, this translates to $16 million per annum from 2011-12 to 2013-14

EnergyAustralia considers debt raising costs to be a necessary expenditure to achieve the operating expenditure objectives. Debt raising costs are costs incurred when obtaining debt used to finance capital investment. Expenditure that is a necessary part of investment required

62 Memorandum dated 29 May 2007 from ACG to ElectraNet titled "Estimation of ElectraNets equity raising transaction cost allowance".

Figure 10.5: Factors that contribute to changes in network support cost over time

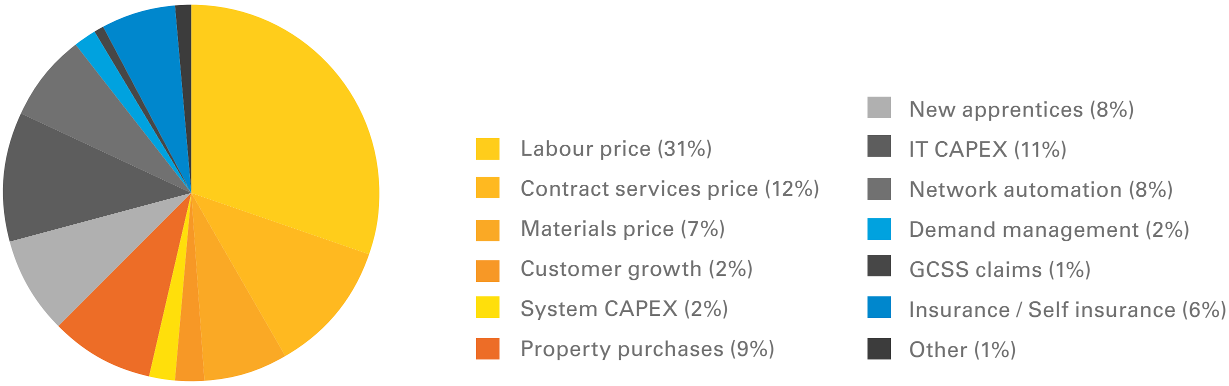
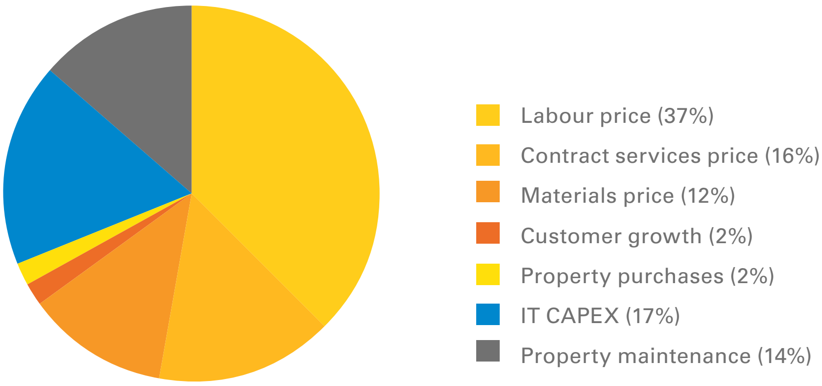


Figure 10.6: Factors that contribute to changes in business support cost over time



by obligations and by the capital expenditure objectives is also consistent with the operating expenditure objectives, because they are in fact the same.

EnergyAustralia believes that debt raising costs are incurred by the business in its endeavour to meet the capital expenditure objectives and is therefore an efficient cost that a prudent operator would incorporate in operating expenditure forecasts used to supply Standard Control Services.

10.5 Operating expenditure for the 2009-14 regulatory period

The many cost activities have been summarised into three main cost categories – maintenance, network support and business support. These are to meet key obligations and are modified by escalation factors. The combination of forecasts across these three categories along with business costs associated with self insurance and capital raising form the operating expenditure forecasts for the period, as summarised in Table 10.6.

Table 10.6: Operating expenditure (FY09 $m real)

FY10	FY11	FY12	FY13	FY14
558	574	593	616	632
Total: $2.97billion				

10.6 Conclusion

The purpose of this chapter was to establish the operating expenditure forecasts to meet the associated objectives. To achieve this;

- the starting point was established in 2006-07, which is demonstrated to be an efficient base from which to forecast;
- escalation of costs based on price and volume escalators (using key inputs and assumptions) was undertaken; and
- any further adjustments to reflect impacts on costs driven by the way EnergyAustralia will meet obligations (step changes) is incorporated.

The cost categories were calculated by applying price and volume escalators and any further adjustments required to determine expenditure by year. The result is an operating expenditure requirement for the control period of $2.97 billion, or $3.07 billion including debt and equity raising costs (FY09 real).

11. Aligning operating expenditure forecasts to rule requirements

11.1 Summary

The purpose of this chapter is to:

- explain how EnergyAustralia has considered Transitional Rule 6.5.6 in our processes and our forecasts; and
- provide further information to enable the AER to satisfy itself that the forecast operating expenditure EnergyAustralia considers is required to achieve the operating expenditure objectives, reasonably reflects the capital expenditure criteria as outlined in the Rules.

RULE REQUIREMENTS

(TRANSITIONAL RULE 6.5.6)

A Building Block Proposal must include the total forecast operating expenditure for the relevant regulatory control period which EnergyAustralia considers is required in order to achieve the operating expenditure objectives.

The AER must accept EnergyAustralia's forecast of required operating expenditure if the AER is satisfied that the total of the forecast operating expenditure reasonably reflects (the operating expenditure criteria):

(1) the efficient costs of achieving the operating expenditure that is included in a Building Block proposal objectives;

(2) the costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In deciding whether or not it is satisfied , the AER must have regard to the following operating expenditure factors:

(1) the information included in or accompanying the Building Block Proposal;

(2) submissions received in the course of consulting on the Building Block Proposal;

(3) analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;

(5) EnergyAustralia's actual and expected operating expenditure during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent EnergyAustralia's forecast of required operating expenditure is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent EnergyAustralia has considered, and made provision for, efficient non-network alternatives.

In Chapters 9 and 10, EnergyAustralia demonstrated the link between:

- the operating expenditure objectives upon which the forecast of operating costs is based;
- the factors that influence operating expenditure over time; and
- the process used to establish the operating expenditure forecast.

The purpose of this chapter is to focus specifically on the AER's considerations relevant to making its decision under 6.12.1(4) of the Rules.

Forecasts that meet the operating expenditure objectives

To achieve the operating expenditure objectives, EnergyAustralia needs to exhibit the following practical characteristics:

- sufficient capability, personnel and systems to manage customer inquiries, customer connections and customer interface including billing. The capability must also extend to an ability to forecast the expected demand for Standard Control Services and the provision of demand management initiatives;
- capabilities to identify and implement compliance strategies for all its regulatory obligations, including obligations that fall outside the NEL's definition of a regulatory obligation or requirements;
- capabilities and systems to monitor the quality, reliability and security of supplies of Standard Control Services;
- capabilities, personnel and systems in place to identify business and system maintenance requirements, and implementation of strategies to ensure the network itself is reliable, safe to operate, safe to work around and is a secure network; and
- has sufficient systems and structures in place to deliver these outcomes.

In order to achieve the practical outcomes that the operating expenditure objectives describe, EnergyAustralia has reviewed its operating expenditure using 2006-07 as a base year, and has considered how costs of delivering outcomes consistent with the objectives is likely to change over time as a result of input cost changes, workload changes or changes to obligations or business functions.

EnergyAustralia has used independent verification of likely cost changes and has linked its operating costs to the capital forecast to ensure that workload factors are taken into account.

Table 11.1 shows the practical outcomes and capabilities that will be delivered at the end of the 2009-14 period that meet the operating expenditure objectives.

EnergyAustralia believes that the maintenance forecast for the 2009-14 period represents a sufficient level of maintenance to meet the operating expenditure objectives.

Section 9.6 notes that EnergyAustralia's maintenance cost requirements are primarily aimed at achieving Objective 4 (maintain the reliability, safety and security of the distribution system through the supply of Standard Control Services). However there are a number of related objectives that maintenance activities support:

- without appropriate levels of system maintenance, EnergyAustralia will fail to meet its obligations and as a consequence, not meet Objective 2; and
- without well targeted maintenance programs, asset failure will become unpredictable and eventually unmanageable. Network reliability will suffer and the quality, reliability and security of supply of Standard Control Services (Objective 3) will be compromised.

11. Aligning operating expenditure forecasts to rule requirements (continued)

Table 11.1: Operating expenditure objectives and outcomes

Meet or manage demand
Capability of meeting customer inquiries
Capability of meeting customer connection inquiries
Accurate billing capability
Capability for investigating and implementing DM
System dis/re-connection to facilitate customer load and demand requirements
Capability for forecasting load & metering of load
Apprentice training
Meet obligations
Identification of obligations, and implementation of compliance strategies:
Systems and capability in place to meet obligations
System maintenance in line with obligations such as Work Cover and safety obligations
Meet obligations such as environmental and OH&S
Maintain quality, reliability and security of supply of services
Capability to implement and operate systems to monitor the quality, reliability and security of services
Restoration and management of outages through emergency works
Emergency call response capability
Appropriate emergency response
Maintain reliability, security and safety of network
Capability to identify maintenance requirements,
Appropriate maintenance of the system to ensure it remains reliable, secure and safe
Apprentice training
GIS data complete and up to date
Response to breakdown failure
Control room operation & network safety

In addition, a failure to adequately maintain network assets will jeopardise public and worker safety and in so doing, EnergyAustralia will not meet its obligations under the OH&S Act, nor its obligations to meet SAIFI reliability targets outlined in the DRP licence conditions.

Both **network and business** support costs achieve all four operating expenditure objectives through various cost activities.

Tables 9.1 and 9.2 show in considerable detail how activities that make up both network support and business support costs link to objectives. The table provides a clear link between cost categories, expenditure objectives, and the drivers of cost change over the period.

Network support costs are also a critical part of the successful operation of a network distribution business. Network support costs are required to:

- operate systems used by engineers to meet or manage the demand for Standard Control Services (Objective 1);
- to operate the system itself so that the network assets themselves will remain protected (objective 4); and
- successfully deliver quality Standard Control Services (objective 3).

Business support costs are critical to the operation of a business the size and scope of EnergyAustralia, which must meet general and specific requirements as a State Owned Corporation. EnergyAustralia cannot function successfully without a corporate finance and executive function (all objectives). Nor can it recoup revenues used to fund investment without appropriate business IT and billing systems. Similarly, the business cannot operate without appropriate accommodation for staff or without appropriate expertise to deliver compliance with regulatory requirements (all objectives).

11.2 Satisfying operating expenditure criteria

Under Transitional Rule 6.12.1(4) the AER is required to either:

(i) accept the total of the forecast operating expenditure for the regulatory control period that is included in the current Building Block Proposal; or

(ii) not accept the total of the forecast operating expenditure for the regulatory control period that is included in the current Building Block Proposal.

If the AER does not accept the total forecast, the AER is required to set out its reasons for that decision and an estimate of the total of EnergyAustralia's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

The AER, therefore, acting in accordance with Transitional Rule 6.5.6 must decide whether it is satisfied that EnergyAustralia's forecast of operating expenditure reasonably reflects the operating expenditure criteria. If it is not satisfied, the AER must determine and substitute an estimate which it considers does reasonably reflect the operating expenditure criteria.

In deciding whether or not the AER is satisfied the AER must have regard to the *operating expenditure factors* (referred to in the beginning of the chapter).

In order to provide sufficient information for the AER to make its decision in accordance with Transitional Rule 6.12.1(4) EnergyAustralia has set out in this chapter to explain how it has taken account of these factors in preparing the forecast.

As mentioned in Chapter 6, EnergyAustralia sought guidance from past AER determinations and from the Rules itself regarding the application of the terms "prudent" and "efficient".

EnergyAustralia also sought an independent opinion from NERA Consulting as to how, from an economic perspective, the Regulatory Proposal should be approached and structured in the context of the above considerations.

EnergyAustralia has reviewed the process used to forecast operating expenditure to identify whether it reasonably reflects the criteria and the factors in light of NERA's advice. NERA's advice and EnergyAustralia's review of its process is summarised against the factors and the criteria in the following sections. NERA's report is included as part of this Regulatory Proposal (Attachment 6.1).

EnergyAustralia's analysis therefore follows the same structure as Chapter 6 which addresses the issues of prudence and efficiency in relation to capital expenditure. It should be noted that objectives, criteria and factors are common to both capital and operating expenditure objectives.

11.3 Having regard to operating expenditure factors

Transitional Rule 6.5.7(e) sets out 10 factors that the AER must have regard to when making a decision as to whether it is satisfied that the forecasts reasonably reflect the operating expenditure criteria.

Some of these factors are not relevant to the preparation of the Regulatory Proposal. Factors 2-3 will be considered by the AER following the submission of our proposal. Factor 8 refers to the incentives inherent in a service target performance incentive scheme in which financial incentives are not to apply in the next period.

Operating expenditure factors specifically considered in the demonstration of prudent and efficient processes include:

- 6.5.7(e)(6) relevant prices of capital and operating inputs;
- 6.5.7(e)(7) substitution possibilities between operating and operating expenditure; and
- 6.5.7(10) the extent EnergyAustralia has specifically considered and made provision for efficient non-network alternatives.

Operating expenditure factors considered in forecasting efficient levels of expenditure include:

- 6.5.7(e)(4) benchmark operating expenditure that would be incurred by an efficient DNSP over the period;
- 6.5.7(e)(5) EnergyAustralia's actual and expected operating expenditure during any preceding periods; and
- 6.5.7(e)(9) the extent the forecast of required operating expenditure is referable to arrangements with a person other than EnergyAustralia that, in the opinion of the AER do not reflect arms length terms.

11. Aligning operating expenditure forecasts to rule requirements (continued)

EnergyAustralia, having regard to the operating expenditure factors outlined in Rule 6.5.6, demonstrates that its forecasts reflect the operating expenditure criteria in three ways:

- our planning, forecasting and decision making processes, which are geared to reflect our circumstances, are grounded in prudent considerations and motivated towards delivering efficient outcomes – see Section 11.4;
- our processes lead to prudent and efficient outcomes through observation of the indicators of an efficient level of expenditure – see Section 11.5; and
- demonstration that our demand forecasts and cost inputs reflect a realistic expectation of future circumstances – see Section 11.6.

11.4 Reflecting the operating expenditure criteria through our planning and forecasting processes

11.4.1 Consideration of key uncertainties including potential adverse consequences

EnergyAustralia has demonstrated that it has a systematic approach to analysing network risk. EnergyAustralia's maintenance program is based on concepts of FMECA and RCM which are designed to balance the risk and consequence of asset failure[63]. A structured approach to managing risk and use of analysis of long term consequences of failure is inherent in the maintenance program and is critical to adequate maintenance and management of network assets.

EnergyAustralia reliability centred maintenance strategy has paid dividends since its implementation. The asset condition and performance information gathered during maintenance has informed critical investment decisions upon which EnergyAustralia has based its capital and operating forecasts.

11.4.2 The approach to forecasting for difference expenditure categories

EnergyAustralia also regards consideration and use of a variety of approaches to forecasting to reflect a prudent and efficient process.

EnergyAustralia has used a common approach across all three operating cost categories to establish a starting point for operating cost forecasts. The manner in which cost changes over time have been applied to forecasts is also consistent across the three categories.

However, maintenance costs have been forecast using a detailed examination of the replacement program which forms part of the capital forecast. This is because asset replacement has a direct impact on the level and nature of maintenance that will be required in the future.

The trade-off between replacement expenditure and maintenance costs has been explicitly modelled using the forecast change in weighted average age of asset classes to determine the change in maintenance costs over time. This approach has not been considered for network support and business support costs as these costs are impacted by the capital program as a whole, rather than a single part of the capital program. Furthermore, there is no trade-off between capital and operating costs in these categories – rather network and business support expenditure move in the same direction as capital expenditure.

11.4.3 Recognition of a DNSP's circumstances

EnergyAustralia's operating expenditure forecast is related to the specific circumstances of its network. The method by which maintenance costs are forecast relies on the application of a reliability centred maintenance philosophy to the particular network assets and thereby takes account of issues such as asset condition, asset age, asset reliability and asset accessibility. All of these factors are specific to EnergyAustralia's network.

EnergyAustralia's subtransmission and distribution networks are characterised by a large number of underground assets. These assets are hard to inspect, difficult to maintain and very costly to replace. The capital investment decisions to replace significant lengths of underground subtransmission feeders has not been made lightly and despite the significant capital costs involved, has been shown to have a beneficial impact on operating costs annually, as well as improvement to reliability and network security.

EnergyAustralia operates within a highly congested residential and commercial area that is characterised by high labour and operating costs. EnergyAustralia has taken account of these factors in its forecast to ensure that the forecast reflects a realistic expectation of cost inputs driven by factors that are specific to EnergyAustralia's circumstances.

63 Failure Modes Effects Critically Analysis (FMECA) and Reliability Centred Maintenance (RCM) are discussed in Section 9.6.

11.4.4 Consideration of the efficiency of the total forecast expenditure, distinct from the efficiency of each individual component of that expenditure

As noted in Chapter 10, the most significant influences on operating costs during the 2009-14 period are our proposed capital investment program and the characteristics of our existing asset base.

An increase in the capital program will affect the workload of resources in each cost activity level. This is offset to some extent, where the capital program results in the replacement of aged assets with relatively higher maintenance requirements. The tightening of the labour market to meet the demand for resourcing in a strong investment cycle will also drive up the cost of labour and flow through to operating expenditure over the period.

All of these effects have been taken into account by EnergyAustralia in framing its forecast of operating costs for the 2009-14 period, which reflects the state of the network assets and the requirement to significantly invest in new assets within the period. EnergyAustralia notes in absolute terms, operating expenditure increases over the period are significant. However, relative to the strong capital expenditure pressures (driving a significant ramp up in costs) operating cost increases are moderate.

Our operating costs must be therefore be considered in the context of the total cost forecast, particularly in the current investment cycle.

Arbitrary operating cost reduction targets when delivering a large investment program would be imprudent. In our current circumstance, efficiency is demonstrated by doing more in a better way, a reason why EnergyAustralia has invested prudently in network and business support initiatives which will allow the organisation to deliver the necessary operational efficiencies to support the large investment program.

11.4.5 Consideration of alternatives

EnergyAustralla has demonstrated in its proposal how it has considered alternative ways of meeting the operating expenditure objectives including reference to the following factors:

- relative prices of operating and capital inputs (Factor 6);
- substititution opportunities between operating and capital expenditure (Factor 7); and
- the extent to which modern network alternatives have been considered and provided for (Factor 10).

EnergyAustralia has considered a range of maintenance approaches and has concluded that a reliability centred maintenance program is essential to preserve the integrity and performance of an aging asset base. This sentiment is supported by SAHA International in their benchmarking report which agreed that the maintenance philosophy chosen by EnergyAustralia was appropriate and in fact optimal given the characteristics of its network.[64]

Relative prices of operating and capital inputs and substitution possibilities (operating expenditure Factors 6 and 7)

EnergyAustralia has explicitly considered the substitution possibilities between capital and operating expenditures. The analysis of the capex/opex trade-off quantifies the growing annual real increase in operating costs that will occur in the absence of the capital investment program, specifically the replacement program.

EnergyAustralia has considered the long term impacts of continuing to substitute operating expenditure for asset replacement and has determined that the outcomes are not consistent with achieving the operating expenditure objectives of maintaining the quality, reliability and security of services, nor with maintaining the reliability, safety and security of the distribution system. This is particularly true in the area of underground subtransmission feeder replacement which is a significant driver of capital expenditure in the 2009-14 period.

64 SAHA International Electricity Distribution Operational Expenditure Review, p58.

11. Aligning operating expenditure forecasts to rule requirements (continued)

SAHA International agrees and states that

"With an increasing proportion of the network exceeding standard lives, … exponentially increasing failure rates are likely and the inability of maintenance to absorb this increase any further is inevitable at some point. The only mitigation strategy for this event is to replace selected assets. Without making any statement on the practicality or cost of replacing underground network assets, it is clear that without replacement, EnergyAustralia's underground network will continue to degrade – leading to increasing maintenance expenditure and/or decreasing reliability."[65]

EnergyAustralia believes that its operating expenditure forecast represents an efficient balance between capital investment and ongoing operational costs.

Consideration and provision for non-network alternatives (capital expenditure Factor 10)

EnergyAustralia has specifically considered the impact of demand management on the capital forecast. The effect of both tariff based and project based demand management is a deferral of approximately $50 million worth of capital investment during the 2009-14 period.

These demand management activities come at a cost in operational terms which EnergyAustralia has factored in to its operating cost forecast. This does not conflict with the operation of the D factor during the period, as the D factor is designed to provide a positive incentive for businesses to seek non-network solutions. The operation of the D factor in its current form presents networks with an over-recovery of costs as the incentive.

If capital deferral is already incorporated into the capital forecast and consequently, the revenue, EnergyAustralia's revenue will be lower than it otherwise would be in the absence of demand management, which is contrary to the incentive. It follows therefore that operating costs should be incorporated in the forecast to ensure that revenue remains unchanged as a result of this forecast demand management activity. The positive incentive payment to networks will be derived from the operation of the D factor mechanism during the period as per its usual operation.

11.4.6 Consideration of the efficiency of the forecast in a medium and long term context

EnergyAustralia's operating expenditure program is designed with consideration of the efficiency of the expenditures in the longer term.

EnergyAustralia's maintenance program is designed to maximise the reliability and performance of an asset over its life which is typically between 45 and 60 years.

EnergyAustralia's apprenticeship training program is designed specifically to meet the needs of an ageing network and workforce in future regulatory control periods. Investing in this type of activity now will ensure sustainability of a quality and reliable service delivery in the medium and long term.

EnergyAustralia's initiatives in demand management, intelligent network and AMI are driven towards managing expected demand in future periods.

11.5 Reflecting operating expenditure criteria through observing indicators of an efficient level of expenditure

11.5.1 Benchmarking of DNSP costs (operating expenditure Factor 4)

The fourth expenditure factor that the AER is required to have regard to is the benchmark expenditure that would be incurred by an efficient DNSP over the regulatory control period. NERA notes in its report that the reference to the "efficient" DNSP should be interpreted as a reference to an "averagely" efficient DNSP rather than a "perfectly" efficient DNSP.

NERA goes on to explain that when comparing the costs of one DNSP against another, one must take account of the factors affecting one DNSP's costs against those to which the DNSP may be compared. NERA notes that

"…once all of the particular characteristics of each DNSPs' business and operating environment are considered, there may be little that can be said about the relative efficiency of the business."[66]

65 SAHA International Electricity Distribution Operational Expenditure Review, p40.

66 NERA Economic Consulting economic interpretation of clauses 6.5.6 and 6.5.7 of the NER, p29.

EnergyAustralia has taken the issue of benchmarking operating costs seriously and engaged SAHA International to undertake a benchmark study of maintenance and other operating costs among Australian DNSPs.

SAHA's study examined maintenance philosophies and practices of EnergyAustralia and five of its peer organisations. SAHA examined the controllable and uncontrollable costs of each business in order to determine relative efficiencies.

The framework used by SAHA recognises costs as one of the following four categories:

Inherent: Inherent costs are those costs that are borne by an organisation due to some third party or environmental influence that cannot be removed – that is, the costs are beyond the ability of the distribution business to change. For example, within a distribution business, geography will be a major driver of inherent costs – due to the fixed nature of the infrastructure.

Structural: Structural costs are those costs that are borne by an organisation due to socio-economic influence or as a legacy of historical events.

Systemic: Systemic costs are those costs that are borne by an organisation due to its own business rules and policies. These costs are generally driven by organisational structures and operating policies and practices.

Realised: Realised costs are those costs that are borne by an organisation due to its own work and labour force management practices. These costs are generally driven by frontline management, labour relations and workforce capacity and capability.

SAHA found that the maintenance philosophies used by peer organisations were different, but that each distributor's methodology was appropriate for its given circumstances and had been applied on the basis of a thorough understanding of its network characteristics. For example, a run-to-fail asset management methodology was shown to be more appropriate for a relatively young network, in contrast to a condition based monitoring regime which may lead to higher costs but have similar reliability outcomes. In contrast, a run-to-fail methodology applied to a network like EnergyAustralia's would be disastrous because failure rates of equipment are significantly higher than peer organisations. For a network operator with an aging asset base, SAHA agreed that condition based maintenance practices produced optimal maintenance outcomes.

As a result of the study SAHA International concluded that

"In terms of OPEX prudence and efficiency, EnergyAustralia achieve similar operating cost outcomes as peer organisations whilst:

- *maintaining higher workloads across most asset classes; and*
- *maintaining lower costs across most asset classes. With respect to the higher workloads, the main drivers appear to be a combination of a number of factors including:*
- *older assets with higher failure rates, leading to more maintenance and targeted preventative maintenance programs;*
- *an RCM based maintenance methodology which leads to the extension of assets past their standard lives (where the condition permits), but at a cost of monitoring assets;*
- *a lower proportion of maintenance repair capitalised, leading to more labour hours recorded against OPEX; and*
- *the proportion of the network in CBD and Urban areas with limited accessibility – leading to greater labour hours due to larger crew sizes for confined space entry and underground access and longer maintenance times related to difficult-to-reach equipment.*

With respect to the lower unit costs, EnergyAustralia enjoy the benefits of the RCM based maintenance strategy process, including:

- *a higher proportion of planned maintenance – leading to a lower cost per maintenance activity/task; and*
- *a greater proportion of direct costs – due to more focussed maintenance programs."* [67]

67 Electricity Distribution Business Operational Expenditure Review, SAHA International, 2008, p52

11. Aligning operating expenditure forecasts to rule requirements (continued)

EnergyAustralia believes that the report written by SAHA represents the first benchmarking report undertaken for Australian DNSPs that is sufficiently detailed to provide meaningful results. Importantly, SAHA recognised the presence of both controllable and uncontrollable costs as a significant factor in reaching its conclusions. This is consistent with NERA's view regarding the importance of accounting for DNSP specific factors.

11.5.2 Comparison with past forecasts and actuals (operating expenditure Factor 5)

One of the factors that the AER must take into account when considering the reasonableness of the operating expenditure forecast is past operating expenditures. NERA, in its report stated that

"to the extent that the regulatory regime is considered to be effective in providing firms with an incentive to become more efficient, the level of costs that a firm has been able to achieve in the preceding regulatory period may be a good starting point in considering what may be the efficient level of costs going forward.

This is particularly the case where the obligations a firm faces in a particular area have not changed between regulatory periods and where the scope of activities required to meet those obligations is therefore expected to remain the same".[68]

EnergyAustralia's approach is similar to that suggested by NERA. EnergyAustralia has developed a starting point from which to forecast operating expenditures for the 2009-14 period. The starting point is based on the last auditable and complete year of financial accounts which is 2006-07. Thus, the level of past operating expenditure fundamentally underpins forecast costs.

EnergyAustralia has taken steps to ensure that the operating expenditure forecasts represent a realistic expectation of demand and cost inputs and has used a process whereby activity costs at the starting point are rolled forward but adjusted for factors that are likely to change the type of obligations or functions required (step changes), the price of cost inputs (price change) or the number of tasks required (volume change). These three drivers of change are linked to external factors as much as possible.

Operating costs overall increase over the period. However, the changes over the regulatory period can be mostly attributable to the change in the forecast price of labour. The labour market for the electricity, gas and water sectors is tight and labour costs are expected to increase at a faster rate than CPI leading to a real increase in labour costs. EnergyAustralia is a price taker in this market and must keep pace with market trends in order to retain skilled staff to meet the capital and operating expenditure objectives. Chapter 10 reconciles differences between forecast and actual operating expenditure in 2006-07. Further explanation of variances between forecast and historic operating expenditure can be found in Attachement 11.1.

11.5.3 Outsourcing to non-related parties (operating expenditure factor 9)

EnergyAustralia does not consider that any part of its forecast operating expenditure is referable to arrangements (with another party) that do not reflect arm's length terms.

EnergyAustralia outsources portions of its maintenance program to external contractors at arm's length. All vegetation management is undertaken by third party contractors who sign outcomes based contracts to deliver vegetation management services. EnergyAustralia spends approximately $20 million on vegetation management per annum, the costs of which can be considered efficient as they are sourced from the market directly.

Pole inspection, pole re-inforcement and meter reading activities are also outsourced on outcomes based contracts.

68 NERA Economic consulting Economic interpretation of clauses 6.5.6 and 6.5.7 of the NER, p27.

11.6 A realistic expectation of demand forecasts and cost inputs

The regulatory framework is such that forecasts of operating costs are not reviewed at the end of the regulatory period. Expenditure above the allowance is not able to be recouped and represents a negative impact on business profitability.

Given the lack of flexibility within the framework, the forecast of operating expenditures must take account of all likely influences on future costs in order for it to represent a prudent forecast. This is supported by the National Electricity Rules which require EnergyAustralia to base its forecast of operating costs on a realistic expectation of demand forecasts.

EnergyAustralia's forecast process has been designed to ensure that it represents a realistic expectation of forecasts of demand for services.

First, EnergyAustralia has assessed all existing expenditure and linked this expenditure to requirements to ensure that EnergyAustralia's starting point is sufficient to meet current obligations and the operating expenditure objectives.

Second, influences on future volumes of work have been assessed and linked to global factors such as growth in customer numbers, or internal factors such as higher maintenance tasks driven by a larger assets base. This step ensures that the scope of the operating expenditure forecast keeps pace with growing requirements during the period.

Third, the program has been split by material, labour and contracted services to enable cost escalation factors to be applied and thereby protect the real value of the proposal.

11.6.1 Demand forecasts

The forecast of demand for Standard Control Services drives capital investment and may also show an increase in customer numbers. Capital investment, together with customer numbers impacts both maintenance and non-maintenance operating expenditure. It is therefore important that the forecast of operating costs takes into account the impact of these drivers.

EnergyAustralia has incorporated the proposed capital investment program as an input to its maintenance program. This has been done using the net increase/decrease of assets that make up the network assuming the forecast capital investment program has been implemented. As the capital program incorporates both new and replacement assets, it is important to consider the impact the programs have on the weighted average age of the population in each asset class in order to establish whether average maintenance costs for a category of assets will go up or down.

The impact of the demand forecast and resulting capital investment program on network support and business support costs is more straight forward. In some cases a direct link can be made. An example is the forecast costs of data creation in the financial system which directly correlates to customer connection applications.

In other cases the link is less direct but nevertheless the demand forecast can be used to inform forecasts of how operating costs will change over time. An example is the costs of EnergyAustralia's call centre which can be linked generally to customer numbers.

11. Aligning operating expenditure forecasts to rule requirements (continued)

11.7 Realistic expectation of cost inputs

Forecasts of operating costs are not reviewed at the end of the regulatory period and therefore, forecasts of operating expenditures must take account of all likely influences on future costs including input cost changes.

EnergyAustralia's methodology and approach to quantifying cost inputs is described in Chapter 10. This is a robust approach that examines volume and price drivers on cost activities. EnergyAustralia's justification of its cost inputs is summarised in Section 10.2 and detailed in EnergyAustralia's Cost Escalation Procedure and the Operational Expenditure Forecasting report.

11.8 Conclusion

The purpose of this chapter was to focus specifically on the considerations the AER must undertake when making a decision under 6.12.1(4) of the Rules. This requires that the total operating expenditure forecast reasonably reflects the efficient costs of a prudent operator in the circumstances and is founded on realistic forecasts, having regard to 10 operating expenditure factors.

As with capital expenditure in Chapter 6, the analysis in this chapter is underpinned by a review of the discretion afforded to the AER in making a decision on its satisfaction with the efficiency and prudency of EnergyAustralia's operating expenditure forecast.

EnergyAustralia has reviewed its operating expenditure forecast process to ensure that the elements of prudence and efficiency have been utilised during the process. EnergyAustralia has demonstrated that it has:

- developed a prudent approach to estimating future operating expenditure needs, built up from a cost activity level;
- developed prudent processes to forecast maintenance requirements over the regulatory control period;
- used benchmarked and independently assessed cost inputs to determine movements in cost requirements over the period;
- prudently considered alternative approaches for service delivery, particularly in the area of maintenance where it has modelled the implications of various capex-opex trade-off alternatives; and
- considered implications of capital and operating expenditure requirements in future periods when considering operating requirements in the current period.

EnergyAustralia is confident that its operating expenditure forecast will achieve the operating expenditure objectives in a manner that reflects the operating expenditure criteria.

12. Corporate income tax

The purpose of this chapter is to demonstrate that EnergyAustralia's estimate of its cost of corporate income tax for each year of the regulatory control period is calculated in accordance with the Rules[69]:

RULE REQUIREMENTS

(TRANSITIONAL RULES 6.5.3, 6.12.1(7))

A distribution determination is predicated on a decision on the estimated cost of corporate income tax to the provider for each year of the regulatory control period in accordance with clause 6.5.3.[70]

EnergyAustralia's estimate of the cost of corporate income tax for each year of the regulatory control period must be included in its Building Block Proposal.

The Rules require that the estimated cost of corporate income tax be based on:

- an estimate of taxable income that would be earned by a benchmark efficient entity as a result of the provision of Standard Control Services if such an entity (rather than EnergyAustralia) operated the business;
- the expected statutory tax rate;
- the assumed utilisation of imputation credits prescribed in the Rules; and
- the cost of debt and the estimated depreciation for tax purposes based on that of a benchmark DNSP.

12.1 Summary

Using the assumptions and forecasts set out below and in accordance with EnergyAustralia's completed PTRM, the annual forecast corporate income tax expense for each year of the regulatory control period is set out in the table below.

Table 12.1: Estimated corporate income tax ($m nominal)

	FY10	2011	2012	2013	FY14
Income tax liability	87	152	176	203	217
Less: Value of Imputation Credits	44	76	88	102	109
Revenue allowance for tax payable	44	76	88	102	109

12.2 Taxable income of a benchmark (efficient) entity

EnergyAustralia is a tax paying entity similar to any other legally incorporated business entity in Australia and through the application of the National Tax Equivalent Regime (NTER), which in turn is based on the Income Tax Assessment Act (ITAA), is subject to the same rules, regulations and principles laid down by the ITAA.

12.3 Benchmark cost of debt

The key benchmark assumption for calculating the forecast corporate income tax expense is the assumed capital structure.

The AER's PTRM uses the same assumed benchmark capital structure prescribed in the Rules for the calculation of the rate of return: 40 percent equity and 60 percent debt financing.

The benchmark interest expense (also sourced from the rate of return calculation) on capital invested is used to derive the forecast corporate income tax expense.

69 Transitional Rule 6.5.3

70 Transitional Rule 6.12.1(7)

12. Corporate income tax (continued)

12.4 Estimated depreciation for tax purposes

The decline in value or tax depreciation deductible depends on the rate permissible under tax law at the time and the calculation method used.

In order to calculate a separate allowance for tax payable under the post tax nominal framework, the tax value of assets constituting the RAB needs to be established as at 1 July 2009.

EnergyAustralia maintains an asset register that details and calculates the tax depreciation and values of all of EnergyAustralia's assets that had been claimed as a deduction in EnergyAustralia's annual tax return.

EnergyAustralia has used the details of assets existing as at 30 June 2007 as maintained in the asset register as well as forecast asset additions to establish the tax values of all of its regulated network assets as at 1 July 2009.

The table below sets out EnergyAustralia's annual forecast income tax depreciation deductions for each year of the regulatory control period.

Table 12.2 Estimated tax depreciation ($m nominal)

	FY10	FY11	FY12	FY13	FY14
Estimated Tax Depreciation	319	251	292	338	389

These forecasts have been calculated:

- using income tax depreciation methods previously elected in EnergyAustralia's annual corporate income tax returns; and
- assuming the prime cost method being applied to all forecast capital expenditure.

EnergyAustralia's forecast tax depreciation on forecast capital expenditure is based on capitalisation and depreciation assumptions which are consistent with the PTRM.

Details of the methodology used to arrive at the opening asset value for tax purposes are found in Attachment 12.1: EnergyAustralia's methodology for calculating the opening tax base.

12.5 Conclusion

EnergyAustralia is a tax paying entity and subject to the same accounting and tax obligations as other businesses. This chapter proposed an estimate of corporate income tax for inclusion in the PTRM based upon the benchmark capital structure prescribed in the Rules. A forecast allowance for the tax depreciation has been provided for the 2009-14 regulatory period. This is in accordance with the Rule requirements.

13. Revenue or price limits (X factors)

In this section EnergyAustralia demonstrates that the proposed X factors for Standard Control Services are consistent with the Rules.

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(11), 6.5.9)

A distribution determination is predicated on a decision on the control mechanism (including the X factor) for Standard Control Services[71].

The Rules require that a Building Block Proposal include the X factor for each control mechanism for each year of the regulatory control period. These X factors[72]:

1. must be set using EnergyAustralia's total revenue requirement;
2. must be set in a way that minimises the variance between the annual revenue requirement in the last year of the regulatory control period and the expected revenue in the last year using the X factors; and
3. must be designed so that the NPV of the expected revenues using the X factor equal the NPV of the total revenue requirement.

X factors are directly related to the control mechanism for the services provided.

As discussed in EnergyAustralia's Service Classification and Control Mechanism Proposal, the Rules prescribe a control mechanism that is substantially the same as the one that applies to the current period[73].

EnergyAustralia proposes that, consistent with Clause 6.2.6(a) of the Transitional Rules, both distribution (DUoS) services and Miscellaneous and Monopoly Services come under the one weighted average price cap (WAPC) control mechanism, with Emergency Recoverable Works excluded.

It is also proposed that Emergency Recoverable Works do not require regulation and therefore do not need a control mechanism (this is discussed further in Part II of the Regulatory Proposal).

Note that in this chapter two sets of X factors are presented: one set for the distribution control mechanism (Section 13.1), and a second set for the transmission control mechanism (at Section 13.4). Two sets of X factors are required to apply to the relevant control mechanisms for pricing purposes.

13.1 X factors for standard control distribution (use of system) services

EnergyAustralia has calculated the following X factors which would apply to EnergyAustralia's distribution use of system (DUoS) Standard Control Services for the next regulatory control period. The X factors were calculated using the PTRM and are shown in Table 13.1. The first year represents the price movement from the previous regulatory control period. The remaining years represent the X value in the formula CPI-X.

Table 13.1: X factors for distribution Standard Control Services

	FY10	FY11	FY12	FY13	FY14
X factor	-29.41	-10.43	-10.43	-10.43	-10.43

Note: a negative X factor represents a real increase in distribution prices.

In accordance with Clause 6.5.9, the proposed X factors have been set to minimise the variance between total annual revenue requirement and total revenues to be earned under the control mechanism. They have also been set to minimise the variance between the annual revenue requirement for the final year and the revenue expected in the final year using the X factors.

71 Transitional Rules 6.12.1(11)

72 Transitional Rule 6.5.9

73 Transitional Rules 6.2.5(c1)

13. Revenue or price limits (X factors) (continued)

Consistent with the AER's convention, the X factor for the first year of the regulatory control period has been set to equal the annual revenue requirement for that year. With the first year's X factor set, the remaining X factors have been set equal to each other, and such that the total annual revenue requirement and total revenues to be earned under the control mechanism are equal in NPV terms. With the X factors calculated, the variance between the annual revenue requirement for the final year, and the revenue expected in the final year using the X factors above is 3.5 percent. That is, the X factor revenue is 3.5 percent above the annual revenue requirement in the final year. This variance is considered immaterial, and satisfies the need to minimise the revenue difference in the final year as discussed above.

13.2 X factors for standard control (miscellaneous and monopoly charges) services

As discussed in Part II of the Regulatory Proposal, Miscellaneous and Monopoly fees and DUoS services are bundled together under a single WAPC control mechanism and are therefore accounted for in the X factors presented above.

EnergyAustralia notes in its service classification and control mechanism proposal that Miscellaneous and Monopoly Services form part of the same set of services as DUoS services. Together these services provide the suite of monopoly distribution services to end use customers. In an end to end view of a new customer wishing to receive supply from the electrical network, most Miscellaneous and Monopoly Services are a necessary first step (or sometimes last step) in that service provision.

As such, it is appropriate that these services are placed under the same umbrella as DUoS tariff services. Such an approach also reduces administrative burden, reducing the number of price caps that would otherwise require separate management, historic volume and price auditing and sign off, both by EnergyAustralia and the AER.

The permissible charges for Miscellaneous and Monopoly Services were originally set by IPART in 1997 and were carried forward unchanged into the 1999 determination. In the current determination, there was a one-off adjustment of approximately 17 percent in 2004, for the change in CPI over five years, but no review of the actual cost of providing these services was carried out.

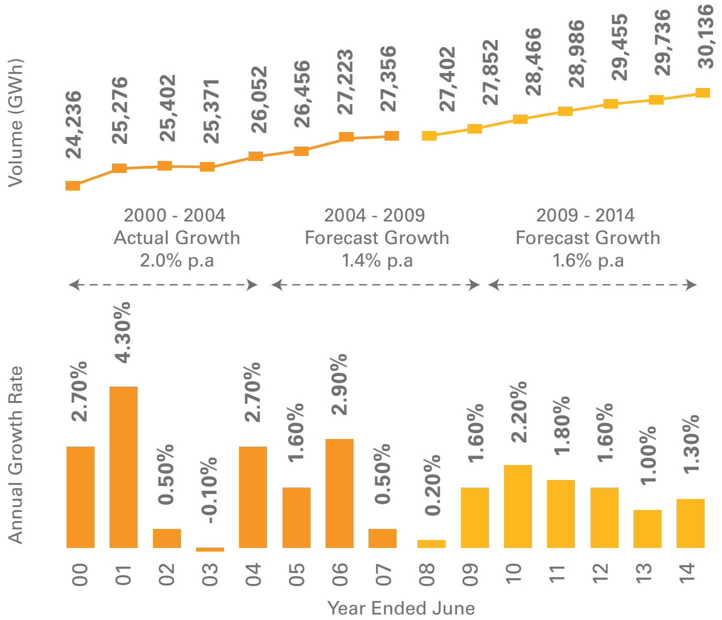
In its 2004 determination, IPART restated an exhaustive schedule of maximum charges for Miscellaneous and Monopoly Services. These charges were not permitted to vary over the period of the determination and no additional charges were permitted to be introduced for new services that might be required.

EnergyAustralia therefore proposes not to establish a separate X factor for Miscellaneous and Monopoly Services. Instead, we propose that:

- the AER's determination would include a schedule of maximum charges for all Miscellaneous and Monopoly Services for the start of the regulatory control period;
- these charges should be cost reflective based on a review of the resources required for each service and would need to recognise the fact there has not been a review of the cost reflectivity of these services in over 10 years;
- during the regulatory control period, each Miscellaneous and Monopoly Service would be considered as an element of the WAPC in the same way as tariffs for the use of the network;
- this would include Miscellaneous and Monopoly Services being subject to the same pricing side constraint as DUoS tariffs and would permit the introduction of new or modified services (where it emerges that the market requires such services), subject to the same reasonable estimates provisions and consultation and approval process as new network tariffs; and
- as part of its determination on the distribution pricing proposal (separate from this distribution determination). the AER could accept or reject any proposed new Miscellaneous and Monopoly Service charges in the same way as any new proposed network tariffs.

A full list of Miscellaneous and Monopoly Services, their functions and indicative prices is found in Attachment 13.1: Applying the control mechanism to Miscellaneous and Monopoly Services.

Figure 13.1 Energy sales – actual and forecast



13.3 Methodology for determining inputs to the X factor calculation

Details of the WAPC calculation can be found in the *PTRM*. EnergyAustralia's assumptions for the WAPC calculation can be found in the notes to the PTRM.

Integral to the calculation is an assumption on volume forecasts over the regulatory control period.

EnergyAustralia's forecast volume growth is outlined in Figure 13.1: Energy Sales - Actual and Forecast above.

EnergyAustralia's proposed volume forecasts are based on robust models which factor in expected trends in the key drivers of electricity usage. The details behind the volume forecasts are set out in Attachment 13.2: Energy and Global Peak Demand forecasts to 2014.

It should be noted that while the methodology for establishing energy growth is specific for the purpose of establishing the volume forecasts, the methodology used incorporates assumptions (as to economic activity, customer behaviour, appliance penetration etc) that are common with those used in establishing peak demand forecasts (referred to in Section 4.2.1).

Therefore any change to an assumption in one methodology must be applied consistently to other methodologies to ensure consistency across the different forecasting models.

EnergyAustralia's volume forecast for each tariff component, together with forecast tariff transfers is contained in EnergyAustralia's completed PTRM (Attachment 1.1), submitted as part of this Regulatory Proposal.

13.4 X factors for standard control (transmission support network) services

As noted in EnergyAustralia's Service Classification and Control Mechanism Proposal, transmission revenues are subject to a revenue cap form of price control[74].

The X factors for EnergyAustralia's transmission support network are shown in Table 13.2.

Table 13.2: X factors for transmission services

	FY10	FY11	FY12	FY13	FY14
X factor	-8.42	-15.77	-15.77	-15.77	-15.77

Consistent with the AER's convention, the X factor for the first year of the regulatory control period has been set to equal the annual revenue requirement for that year. With the first year's X factor set, the remaining X factors have been set equal to each other, and such that the total annual revenue requirement and total revenues to be earned under the control mechnaism are equal. With the X factors calculated, the variance between the annual revenue requirement for the final year, and the revenue expected in the final year using the X factors above is 3.4 percent. That is, the X factor revenue is 3.4 percent above the annual revenue requirement for the final year. This variance is considered sufficiently small to avoid the need to explore other approaches in setting the X factors.

This is consistent with the approach adopted in the ACCC determination in 2004-09.

13.5 Developing X factors using the post tax revenue model

EnergyAustralia is in the unique position of owning both transmission and network infrastructure which are separately priced. Modifications are required to establish the X factors for the transmission and distribution networks.

Details of this division of revenue are found in Chapter 6 of EnergyAustralia's Service Classification and Control Mechanism Proposal. For calculation of the X factor, the PTRM must be established for the separate revenue amounts (for transmission and distribution) so that the X factors for each service can be established.

EnergyAustralia specifically identified system assets as transmission or distribution when populating the PTRM to determine annual revenue requirement. Two separate models were then generated, one with the transmission asset classes deleted, and one with the distribution asset classes deleted.

74 Transitional Rules 6.2.5(c1) notes that the control mechanism for EnergyAustralia's Prescribed (Transmission) Standard Control Services provided in the regulatory control period 2009-14 must be substantially the same as that previously determined by the ACCC in 2005.

13. Revenue or price limits (X factors) (continued)

At this point, operating expenditure and other non-system costs are apportioned using the cost allocation method, and the relevant X factors can be calculated directly from these models. This approach must be applied because EnergyAustralia's Cost Allocation Method for Operating Expenditure relies on splitting operating expenditure at an asset class level. This approach does not lend itself to being applied to the revenue outputs of the PTRM, but must be accounted for in the asset class inputs. This therefore requires building two PTRM models to deliver two revenue outcomes to determine two sets of X factors.

In this way, three PTRM models are presented, one as a whole of business and two as the separate business components. This allows for transparency from the revenue proposal to the setting of X factors for pricing purposes.

13.6 Adjustments to X factors

The X factors determined at the beginning of the regulatory control period in accordance with 6.5.9 are adjusted on a yearly basis to reflect the following mechanisms required under the Rules:

- D factor;
- DM Innovation Fund; and
- any other incentive mechanism.

These adjustments when made to the determined X factors represent the CPI – X limitation referred to in Part I of the Transitional Rules. Adjustments to the X factors is further discussed in Part II Service Classification and Control Mechanism proposal.

13.7 Increments/decrements to the annual revenue requirement

EnergyAustralia has identified that increments and decrements to the annual revenue requirement that may occur due to Pass Through Events.

It should be noted that a revocation and substitution event acts to establish a new set of X factors, and does not act to modify the X factors determined at the beginning of the regulatory control period. Application of pass through events to the control mechanism is discussed in EnergyAustralia's Service Classification and Control Mechanism proposal.

13.8 Conclusion

This chapter deals with the X factors, which it is proposed would apply to prices or revenue for the duration of the regulatory period. X factors arise from the application of the PTRM to the underlying building block cost components.

EnergyAustralia's situation is complicated by the need for separate X factors to apply to transmission and distribution Standard Control Services. These services are subject to different price control formulae: a revenue cap, in the case of transmission; and the WAPC, in the case of distribution. In each case, the X factor has been chosen to be compliant with the Rule requirements in respect of NPV neutrality and final year price level.

Adjustments to the X factors are proposed for a range of mechanisms required under the Rules and for the pass through events described in Chapter 15.

14. Application of incentive mechanisms

In this chapter EnergyAustralia demonstrates:

- how EnergyAustralia proposes incentive schemes will apply during the regulatory control period; and
- that EnergyAustralia's preferred methodology for establishing the RAB at the commencement of the following regulatory control period is consistent with the revenue and pricing principles[75].

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(8), 6.12.1(9))

A distribution determination is predicated on:

- a decision on whether depreciation for establishing the RAB as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure[76].
- a decision on how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme is to apply to the DNSP[77].

14.1 Capital expenditure incentive

The national framework applies incentive mechanisms aimed at rewarding businesses for spending below forecast operating and capital expenditure (and consequently penalising businesses spending above forecast).

In respect of incentive arrangements for capital expenditure, the AER must make a decision, at the time of the determination, whether the regulatory asset base at the end of the next regulatory control period will be adjusted for:

(a) actual depreciation; or

(b) regulatory depreciation.

This decision will affect the strength of the incentive for EnergyAustralia to reduce capital expenditure during the regulatory control period.

In either case, prices during the period of the determination remain unaffected, regardless of whether the capital expenditure allowance is under or over-spent. Prices include an allowance for the return on and return of the approved capital expenditure allowance.

The difference in the strength of the capital expenditure incentive arises from the treatment of assets at the end of the determination, when they are rolled into the RAB. This is as follows:

(a) Actual depreciation "high powered incentive":

- Asset over expenditure is depreciated to the end of the period and added to the RAB. The DNSP loses both the return on and of capital for the period of the determination.
- With under expenditure, the DNSP retains both return on and of capital for the period of the determination and the RAB is adjusted for actual depreciated capital expenditure.

(b) Regulatory depreciation "low powered incentive":

- Asset over expenditure is added to the RAB at cost. Effectively the DNSP loses just the return on capital for the determination period.
- With under expenditure, the DNSP retains the return on capital for the period of the determination and the RAB is adjusted for actual capital expenditure and regulatory depreciation.

If the AER decides that the closing RAB will be adjusted for actual depreciation (high powered incentive), rather than regulatory depreciation (low powered), then:

- EnergyAustralia would benefit more, where lower than forecast capital expenditure results in actual depreciation being lower than forecast revenue allowance for depreciation in any regulatory year; or
- EnergyAustralia would be penalised where higher than forecast capital expenditure results in actual depreciation being higher than the forecast revenue allowance for depreciation in any regulatory year.

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75 Section 7A National Electricity Law: establishes the revenue and pricing principles the AER must take into account when exercising a discretion under the Rules

76 Transitional Rule 6.12.1(8)

77 Transitional Rule 6.12.1(9)

EnergyAustralia believes the AER has discretion in respect of the compounding "power" of the incentive, to ensure that it promotes economic efficiency in accordance with Section 7A of the NEL[78].

EnergyAustralia proposes a low powered methodology apply for the 2009-14 regulatory control period. This is similar to the approach taken by IPART in recent distribution determinations.

As mentioned in our discussion on capital expenditure, EnergyAustralia is in the position of needing to invest to meet our regulatory obligations and requirements and meet the demand of the network during a time of significant replacement need. There are significant uncertainties that EnergyAustralia must face during the regulatory control period (cost escalation, resourcing etc) that would warrant a lower powered methodology.

In short, EnergyAustralia believes that higher powered methodologies are more appropriate where costs of the business are better known and investment in the network is more stable. Where costs and deliverability are less certain, incentives to defer expenditure are not effective in promoting overall economic efficiency.

EnergyAustralia believes that, consistent with Section 7A of the NEL, a lower powered mechanism is one that is that is more likely to promote economic efficiency. It reduces the incentive to defer investment at the risk of network performance and removes windfall gains or losses on deliverability of the capital program which are not met or exceeded.

14.2 Demand management incentive scheme

The transitional Demand Management Incentive Scheme (DMIS) published by the AER for this review contains two main elements, a D factor and an Innovation Allowance. EnergyAustralia's proposal on how these should apply are set out below.

14.2.1 D factor

The AER guideline on the Demand Management Incentive Scheme released on 1 March 2008 sets out that the Demand Management Incentive Scheme will include a D factor arrangement consistent with the scheme applied by IPART in the current regulatory control period.

The IPART D factor provides for the recovery of economic demand management activities and the recovery of lost revenues associated with economic non-network constraint activities to remove any disincentives to undertake efficient demand management. EnergyAustralia supports this approach, and the continued application of the processes, procedures and assessment criteria employed by IPART over the 2004 to 2009 regulatory control period (as attached to the AER's 29 February 2008 decision).

To assist the AER in ensuring consistent application of the D factor over the 2009-14 regulatory period EnergyAustralia has included as Attachment 14.1 to this proposal the D factor submissions and independent expert reports submitted to IPART over the current regulatory period.

14.2.2 Demand management innovation allowance

The AER has also proposed a "Demand Management Innovation Allowance Scheme" to operate parallel to the D factor over the next regulatory control period with a maximum annual amount of $1 million being claimable by EnergyAustralia.

While maintaining its preference for a more generous incentive scheme, EnergyAustralia nevertheless welcomes the AER's proactive approach to encouraging innovation in the area of demand management.

78 Section 7A of the NEL described revenue and pricing principles which include the principle that the DNSP be provided with effective incentives in order to promote economic efficiency.

EnergyAustralia notes and appreciates the AER's efforts to minimise the administrative burden of implementing the Innovation Allowance. However, EnergyAustralia has proposed how the allowance should be applied to EnergyAustralia over the 2009-14 regulatory period. This includes procedural and administrative proposals to enable its effective and consistent application.

This is discussed more fully in Attachment 14.2 – Application of the Demand Management Incentive Allowance.

14.2.3 Enhancing the application of the innovation allowance for EnergyAustralia

EnergyAustralia believes that the AER has a real opportunity under the Transitional Rules to play a leading role in establishing short term incentives with the potential to drive longer term efficiencies.

The incentive under the current ex ante regulatory framework and the associated Efficiency Benefit Sharing Scheme is to contain both capital and operating costs to below the regulatory allowance. There is a clear disincentive for a DNSP to engage in activities of an experimental nature which may have the potential of reducing longer term operating or capital costs.

Therefore, as an extension to the Demand Management Incentive Scheme, EnergyAustralia proposes that a further $5 million per annum be made available for network based innovations that are not readily foreseeable or quantifiable at the beginning of the regulatory control period. This arrangement is proposed as an I factor which would operate in the same way, but be in addition to the $1 million per annum made available under the AER's demand management innovation allowance and provisions of the D factor scheme.

Under the I factor arrangement, the majority of proposed projects would be directed at broad based network related demand management innovations and could include projects such as asset management and communications improvement, and other more general areas of improved products and network management designed to deliver customer benefits.

EnergyAustralia's proposed I factor arrangement is not untested. The public interest that can be achieved through technological and process innovations has been a matter of some debate in recent times in the UK. It has been clearly demonstrated in the UK that investment in research and development activities all but ceased with the introduction of incentive regulation.

To address this concern and to provide the basis for future efficiencies, the UK energy regulator Ofgem has initiated a new scheme that provides significant allowances to network related innovations by use of an innovation funding incentive (an I factor). Examples of the myriad of types of projects contemplated by this scheme were first outlined in a 2004 Ofgem report (Attachment 14.3).

Since introducing the scheme, innovation investment by infrastructure businesses has increased rapidly, demonstrating the significant scope for researching better and cheaper ways of delivering infrastructure services.

EnergyAustralia also believes that such an arrangement is entirely consistent with the Transitional Rules framework and the guideline.

EnergyAustralia's Demand Management Innovation Allowance states that projects eligible for recovery will fall within the following criteria which the AER will consider when reviewing DNSPs' applications:

- demand management programs claimed under the scheme should not be recoverable under categories of the D factor;
- costs recovered under the scheme must not be recovered under any other state or Australian government schemes;
- demand management programs to be recovered under the scheme should be innovative, and/or target broad–based demand reductions across the DNSPs' networks; and
- recoverable programs may be tariff or non–tariff based, however the foregone revenue of tariff based demand management will not be recoverable under the scheme.

14. Application of incentive mechanisms (continued)

EnergyAustralia therefore submits that, as an extension to the Demand Management Incentive Scheme applied to EnergyAustralia, that the innovation allowance (an I factor) be expanded by an additional $5 million per annum to allow EnergyAustralia to undertake demand management programs which have a network focus. Programs to be recovered under the scheme should be innovative, and/or target broad–based demand reductions across the DNSPs' networks.

The administration of the allowance would be similar to the arrangements proposed under the guideline. However, at the time of application, EnergyAustralia should state whether the proposed innovation program is targeting network or non-network solutions.

14.2.4 Carry forward of existing scheme

To give full effect to the D factor mechanism, foregone revenues attributed to DM projects undertaken in the current regulatory period must be provided for in applying the D factor scheme. The IPART scheme as adopted by the AER was the initial application of the scheme and as a result was not drafted to take into account inter-regulatory period considerations.

EnergyAustralia interprets the definition of Regulatory Control Period in clause 11.1 of the D factor scheme to mean any regulatory control period. This would facilitate the inclusion of estimates of foregone revenues from DM measures implemented in the current regulatory period to be included in D factor calculations over the 2009-14 regulatory period, consistent with the intention and historic operation of the D factor scheme.

Consistent with historic application of the D factor EnergyAustralia will seek and submit independent experts' reports to demonstrate the reasonableness of any ongoing foregone revenue impacts associated with previous DM measures.

14.3 Efficiency benefit sharing scheme

The AER has introduced a scheme (Efficiency Benefit Sharing Scheme) with the primary purpose of ensuring that DNSPs have the same incentives to seek operating expenditure efficiencies in each year of the regulatory period. However the scheme introduced by the AER and the extent to which the application of the scheme meets this purpose is untested.

EnergyAustralia has reviewed the AER's model. It is clear that the model supports the sharing of benefits from one-off savings and ongoing saving programs. However, what is unclear is how the balance and magnitude of sharing will be affected by the setting of efficient operating expenditure allowances in future regulatory periods.

EnergyAustralia's modelling has shown anomalous outcomes from the model under certain conditions that are set out in Attachment 14.4: EnergyAustralia's Analysis of the Efficiency Benefit Shairng Scheme. In recognition of these results, and the uncertainty of how the operating expenditure building block will be set for future regulatory periods, EnergyAustralia proposes a safety net application of the scheme that would allow it to be suspended by setting all carry over amounts to zero at the mutual agreement of EnergyAustralia and the AER.

The EBSS explicitly assumes that, unless otherwise adjusted, all variances between forecast and actual operating expenditure are efficiency driven. To provide support to this necessary assumption, the EBSS provides for adjustments to be made to the forecast operating expenditure to restate the forecast costs based on changes in scale and scope.

In its final decision the AER defined changes of scale and scope to be variances in peak demand and changes to statutory obligations respectively.

EnergyAustralia proposes to engage with the AER to develop a process by which changes of scale and scope can be accounted for the calculation of the EBSS incentive amounts.

Furthermore, the AER has made two provisions for operating expenditures to be excluded from the EBSS. To provide neutral incentives relating to non-network alternatives, all expenditures relating to such activities are to be explicitly excluded. In recognition of the Victorian appeal panel's decision that the Office of the Regulator-General's (ORG's) carry-over mechanism must reflect actual efficiency gains and losses the AER's EBSS provides for the DNSP to include a list of "uncontrollable" costs that will be excluded from the operation of the EBSS.

In this proposal EnergyAustralia has not forecast any operating expenditure related to the funding of non-network alternatives. EnergyAustralia proposes to identify any such operating expenditure to the AER during the annual regulatory account processes for their exclusion from the calculation of the EBSS.

EnergyAustralia has not sought exclusion for uncontrollable costs at this time and therefore information defining uncontrollable costs has not been provided as part of this proposal.

14.4 Service target performance incentive scheme

The AER has established that the *Service Target Performance Incentive Scheme (STPIS)* to apply for the 2009-14 regulatory period is to be a paper trial. EnergyAustralia has been strongly supportive of commencing the regime by first capturing data and undertaking prudent analysis to identify the implications and operation of the scheme.

EnergyAustralia has long held that a scheme that relies solely on average measures is less likely to deliver the appropriate incentives to manage poor performance for all customers, and that such measures are likely to be overly sensitive to exogenous factors, reducing the ability of DNSPs to effectively respond to the incentive.

However, at the time of promulgating the *STPIS* under the Transitional Rules, the AER was not in a position to establish the measures that would be reported under the data collection exercise.

Furthermore, the AER is undertaking a review to develop a national STIPIS. The transitional STPIS decision indicated that the AER would utilise the outcomes of the national STPIS process, occurring concurrently with the regulatory review, to inform its decision on the measures to be reported in the data collection exercise.

EnergyAustralia holds reservations that the transitional STPIS does not identify a minimum set of reporting measures. EnergyAustralia is particularly concerned that the national scheme is being developed concurrently to the development of this proposal, and therefore the ability for EnergyAustralia to engage in the process is limited. Further, EnergyAustralia is concerned that the information issues identified and accepted by the AER in the transitional STPIS may not be adequately reflected by simple adoption of a national scheme.

Therefore, EnergyAustralia proposes that the data collection exercise constituting the transitional STPIS applying to EnergyAustralia should include a minimum set of measures that may be reviewed at a later date. EnergyAustralia believes that the most appropriate measures are those that:

- will be common to all NSW DNSPs;
- are applied using consistent definitions; and
- that will demonstrate sufficient data integrity.

EnergyAustralia proposes that the reliability measures contained within the DRP licence conditions[79] satisfy these requirements. In addition, the licence conditions promote greater granularity of reliability information at the feeder category and individual feeder levels as set out below.

The DRP licence conditions contain requirements relating to SAIDI and SAIFI measures of reliability applied to both feeder categories and to individual feeders.

Schedule 2 – Reliability Standards specifies the categorisation of feeder types that EnergyAustralia must report against and the prescribed standards that EnergyAustralia should achieve for each category between 2005/06 and 2010/11.

79 Attachment 4.4 – Design, Reliability and Performance licence conditions

14. Application of incentive mechanisms (continued)

Schedule 3 – Individual Reliability Standards specifies the strict performance standard values for SAIDI and SAIFI that all feeders should achieve within each feeder category.

Schedule 4 – Excluded Interruptions defines an exhaustive list of interruptions that may be excluded from the reported reliability outcomes. Schedule 4, in combination with the definitions established in the licence conditions, ensure consistent reporting of the reliability outcomes over time and across the NSW DNSPs.

EnergyAustralia is required to report on these measures in its annual Network Performance Report. The 2006-07 report is available on EnergyAustralia's website. EnergyAustralia notes that the reliability data included in this report has been subject to independent audit in accordance with clause 18.7 of the licence conditions.

EnergyAustralia proposes that in implementing the STPIS the AER uses the annual Network Performance Report as the official audited public source for the data capture process.

14.4.1 Carry forward of existing scheme

As noted in Chapter 5 of Part II of this proposal, the Maximum Allowed Revenue relating to the transmission portion of our annual revenue requirement will be adjusted by any carry forward of adjustments arising from the application of the Service Target Performance Incentive Scheme for Transmission in the current regulatory control period.

14.5 Conclusion

This chapter proposed how the incentive mechanisms associated with the regulatory framework will apply in the 2009-14 regulatory period.

The AER must make a decision on whether actual or forecast depreciation is to be included in the RAB at the end of the regulatory period. EnergyAustralia proposes that forecast or regulatory depreciation would be more efficient, to avoid magnifying the already significant uncertainties associated with EnergyAustralia's expanded capital expenditure program.

The Demand Management scheme proposed by the AER is similar to that imposed by IPART in the 2004-09 regulatory period, with minor enhancement. EnergyAustralia is advocating the further extension of this scheme to encourage business innovation, in much the same manner as the "I factor" scheme currently in operation in the United Kingdom.

The Efficiency Benefit Sharing Scheme proposed by the AER is believed to produce anomalous outcomes under some conditions and we propose that this mechanism should be refined.

Finally, we look forward to working with the AER to develop the Service Target Performance Scheme, which will initially operate as a paper trial. We view its harmonisation with jurisdictional planning, performance and reporting requirements as highly desirable.

15. Pass through events

In this chapter EnergyAustralia proposes additional pass through events for the purposes of the determination.

> **RULE REQUIREMENTS**
> (TRANSITIONAL RULE 6.12.1(14))
>
> Section 6.12.1(14) of the Transitional Rules provides that a distribution determination is predicated on a decision on the additional pass through events that are to apply for the regulatory control period[80].
>
> Schedule 6.1.3 of the Transitional Rules provides that a Building Block Proposal must contain a proposed pass through clause with a proposal as to the events that should be defined as pass through events.

Chapter 10 of the Rules defines four events as pass through events. In summary, these are:

Regulatory Change Event: is a change in a regulatory obligation or requirement[81] that falls within no other category of *pass through event* and occurs during the course of a regulatory control period. In addition, the change in the regulatory obligation or requirement must substantially affect the manner in which a TNSP provides Prescribed Transmission Services or a DNSP provides Direct Control Services. The change must also materially increase or decrease the cost of providing those services.

Service Standard Event: is a legislative or administrative act or decision that has the effect of:

- substantially varying the manner in which a TNSP is required to provide a Prescribed Transmission Service, or a DNSP is required to provide a Direct Control Service; or
- imposing, removing or varying minimum service standards applicable to Prescribed Transmission Services or Direct Control Services; or
- altering the nature and scope of the Prescribed Transmission Services or Direct Control Services.

The act or decision must also materially increase or decrease the costs to the service provider of providing Prescribed Transmission Services or Direct Control Services.

Tax Change Event: is a change in, or removal or imposition of, a relevant tax payable by a TNSP or a DNSP which materially increases or decreases the cost to the service provider of providing Prescribed Transmission Services or Direct Control Services.

Terrorism Event: is an act of any person or group which, from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons, which materially increases the costs of providing Direct Control Services or Prescribed Transmission Services.

Under the Transitional Rules, each of the above events could be the subject of a pass through application under clause 6.6.1 of the Rules if they entail materially higher or lower costs in providing Direct Control Services or Prescribed Transmission Services. This chapter focuses on the additional pass through events EnergyAustralia proposes for the determination.

80 Transitional Rule 6.12.1(14)

81 National Electricity Law, Section 2D

15. Pass through events (continued)

EnergyAustralia considers that acceptance of these additional pass through events is critical to the fair and equitable operation of the incentive scheme that is proposed to apply to EnergyAustralia's operating expenditure during the 2009-14 period. The occurence of any of the following events in the absence of a pass through mechanism will have the effect of penalising EnergyAustralia for expenditure it is obliged to incur above the forecast allowance determined by the AER. Given that this expenditure is driven by events over which EnergyAustralia has little or no ability to control, the effect would be to undermine the fair operation of an operating expenditure incentive mechanism designed to positively influence business behaviour to deliver efficient operating expenditure outcomes, the benefits of which are shared by both the business and customers.The additional pass through events proposed by EnergyAustralia have added importance given the rigidity of the current framework applying to EnergyAustralia's distribution and transmission networks in the 2009-14 regulatory control period, which does not allow for contingent projects, re-openers or ex-post review.

By way of explanation, EnergyAustralia is both a TNSP and a DNSP for the purposes of the Rules. Section 6.1.6 of the Rules applies specifically to EnergyAustralia and provides, in summary, that for the purposes of the 2009–14 regulatory control period, EnergyAustralia's transmission support network is deemed to be part of EnergyAustralia's distribution network for the purposes of Chapters 6 and 6A of the Rules. It also provides that services provided in connection with EnergyAustralia's transmission support network that would otherwise be "Prescribed Transmission Services" are classified as Standard Control Services and referred to as "EnergyAustralia Prescribed (Transmission) Standard Control Services".

Accordingly, for the purposes of EnergyAustralia's pass through clause for the 2009–14 regulatory control period, and the proposed pass through events addressed in that clause, EnergyAustralia has used the term "EnergyAustralia Prescribed (Transmission) Standard Control Services" to refer to services that would otherwise be classified as "Prescribed Transmission Services" under the Rules.

15.1 Pass through events occuring prior to 30 June 2009 (dead zone events)

Each of the defined pass through events must occur during the 2009–14 regulatory control period to fall within the definition of *pass through event* in the Rules. This means that any event occurring during the final year of the current regulatory control period, which has a cost impact in the next regulatory control period (but has not been included in the operating and capital expenditure forecasts) is not captured as a pass through event under the Transitional Rules.

EnergyAustralia has discussed this issue with the AER, principally in the context of a mandated roll out of AMI during the current regulatory control period. In those discussions, the real possibility of a decision being made to mandate the roll out of AMI by DNSPs during the last year of the current regulatory control period was canvassed. In those circumstances, virtually all of the AMI cost impacts would take place in the next regulatory control period, but the event would not be a pass through event for the purposes of that regulatory control period. Based on those discussions, EnergyAustralia proposes the following additional pass through events for the determination:

Dead zone event: is any pass through event that occurs during the 2004–09 regulatory control period and has a cost impact in the next regulatory control period, that has not been included in EnergyAustralia's capital and operating expenditure forecasts (as accepted or substituted by the AER) for that period.

Including a dead zone event as a specific pass through event in the determination ensures that otherwise legitimate cost pass throughs for the 2009–14 regulatory control period are not precluded purely on the basis of the timing of the event.

15.2 Force majeure event

EnergyAustralia also proposes that the determination include a pass through for unforeseen weather related and other "act of God" type events beyond the reasonable control of EnergyAustralia. EnergyAustralia proposes a specific pass through event covering force majeure events such as major storms, earthquakes and fire and other events beyond EnergyAustralia's reasonable control.

EnergyAustralia experienced major network damage as a result of the once in a 100 year storm that hit Newcastle and the Central Coast on the June long weekend in 2007. Although much of the recovery was capitalised, the storm resulted in an additional $10 million in operating costs in 2006-07 which could not be recovered through pricing. A similar major event, and in particular two or more such events during a regulatory control period, would seriously compromise EnergyAustralia's ability to work within its operational expenditure forecast.

EnergyAustralia therefore proposes the following additional pass through event (in summary) for the determination:

Force majeure event: is any fire, flood, earthquake, storm or other weather-related event or natural disaster, act of God, riot, civil disorder or rebellion or other similar cause beyond the reasonable control of EnergyAustralia that occurs during a regulatory control period and materially increases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

15.3 Cost or demand input variance event

EnergyAustralia proposes that the variance in actual cost movements or demand for the regulatory control period from cost movements or demand forecasts used in the capital and operating expenditure forecasts for that period should be included as a pass through event.

Effectively, EnergyAustralia is requesting a pass-through event to cover unexpected or unforeseeable changes in demand or cost movements that either trigger new investments or materially alter the costs of current or planned investments. The proposed pass through event is symmetrical, so that any material decrease in the cost of providing services is also subject to a pass through. Given that unexpected or unforeseeable changes in demand or cost inputs are beyond EnergyAustralia's control, EnergyAustralia considers it reasonable for risk in relation to these events to be shared with customers. EnergyAustralia will bear the risk of changes in demand or variances in cost movements with an impact below the proposed materiality threshold, but seeks a pass through of the costs of providing services above this materiality threshold.

EnergyAustralia therefore proposes the following additional pass through clause (in summary) for the determination:

Cost or demand input variance event: is an event involving any change in actual cost movements or demand during the regulatory control period from cost movements or demand forecasts used in EnergyAustralia's expenditure forecasts (as accepted or substituted by the AER) that materially increases or decreases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

15.4 Joint planning event

EnergyAustralia conducts joint planning with TransGrid and other NSW DNSPs to comply with joint planning requirements applicable to EnergyAustralia under Chapter 5 of the Rules.

Where a jointly planned capital project is delayed by another party to joint planning, a new project requirement is identified, or there is a change in allocation of responsibilities as between EnergyAustralia and a party to joint planning in relation to an existing project, an additional cost burden can be imposed on EnergyAustralia. Where these additional costs arise solely as the result of actions of another organisation, EnergyAustralia is not able to control or manage these costs.

EnergyAustralia also relies on TransGrid and other DNSPs to provide timely information on new projects relevant to joint planning. This information informs EnergyAustralia's network planning approach in the relevant network area, and is used by EnergyAustralia to plan prudent and efficient outcomes. To the extent that joint planning requirements for the next regulatory control period change, or new joint planning requirements emerge, EnergyAustralia seeks a pass through of any material increases of decreases in the cost of providing services arising as a result of these new, or changed, requirements.

EnergyAustralia therefore proposes the following pass through event (in summary) for the determination:

Joint planning event: is an event involving a change to a capital project the subject of joint planning between EnergyAustralia and TransGrid, or EnergyAustralia and another NSW DNSP, or a new project relevant to joint planning that is beyond EnergyAustralia's reasonable control and materially increases or decreases the costs to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

15.5 Compliance event

The definitions of *regulatory change event* and *service change event* in the Rules do not capture all of the legislative and other obligations that apply to EnergyAustralia in running its business and its network. A *regulatory change event* is defined by reference to regulatory obligations or requirements as defined in Section 2D of the National Electricity Law. This definition is relatively limited in its application. Similarly, a *service standard event* does not cover changes in compliance obligations other than those arising from a legislative or administrative act or decision.

To address this gap, EnergyAustralia proposes a pass through event to address changes to its compliance obligations outside the definitions of *regulatory change event* and *service change event*. EnergyAustralia's proposed pass through event (in summary) is set out below.

Compliance event: is an event other than a *service standard event or a regulatory change event* involving:

- a change in a compliance obligation (meaning a general law obligation or a requirement of a non-mandatory code, standard or guideline which represents standards acceptable to the workforce or to the community); or
- a change in the way a compliance obligation is interpreted; or
- any new compliance obligation, which materially increases or decreases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

EnergyAustralia considers that there may be a number of changes with a compliance impact for EnergyAustralia that may fall within this category, including potential obligations in relation to electro-magnetic fields, greenhouse gas emissions and biobanking. As EnergyAustralia is not aware of the scope or impact of these obligations at this stage, it is unable to cost them. To the extent that these changes, if implemented, do not fall within the categories of r*egulatory change event or service change event*, EnergyAustralia seeks comfort that any material increases in the cost to EnergyAustralia of supplying services as a result of these obligations will be covered by the *compliance event* pass through event category.

15.6 Customer connection event

EnergyAustralia proposes that any material increases in costs associated with the augmentation of the network to meet a large transmission or subtransmission network connection requirement or to establish a new substation to supply load requested by a developer or end use customer be included as a specific pass through event in the determination. As these requirements are initiated by customers or developers on an "as needs" basis during the regulatory control period, EnergyAustralia is not able to accurately forecast these types of customer connection requirements in advance. So that it does not bear the full risk of increases in costs beyond its control, EnergyAustralia seeks to be able to pass through increases in the cost of supplying services beyond an agreed materiality threshold arising from customer connections.

EnergyAustralia proposes the following pass through event (in summary) for the determination:

Customer connection event: is a transmission or subtransmission network connection for a developer, an end-use customer or a generator, or a requirement for EnergyAustralia to establish a new substation to supply load requested by a developer or end-use customer that materially increases or decreases the costs, relative to those allowed in the proposal, to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

15.7 Separation event

The New South Wales Government is currently considering whether EnergyAustralia's retail business should be separated from its network and other businesses, and the form any such business separation should take. At this stage, as the form of any business separation has not been finalised, EnergyAustralia is unable to scope or cost a separation event.

EnergyAustralia proposes a pass through event to address material increases or decreases in costs arising from business separation as follows:

Separation event: A separation event is any legislative or administrative act or decision to separate any business or function of EnergyAustralia in whole or in part from any other business or function of EnergyAustralia, which materially increases or decreases the costs to EnergyAustralia of providing Standard Control Services, including EnergyAustralia Prescribed (Transmission) Standard Control Services.

15.8 Proposed pass through clause

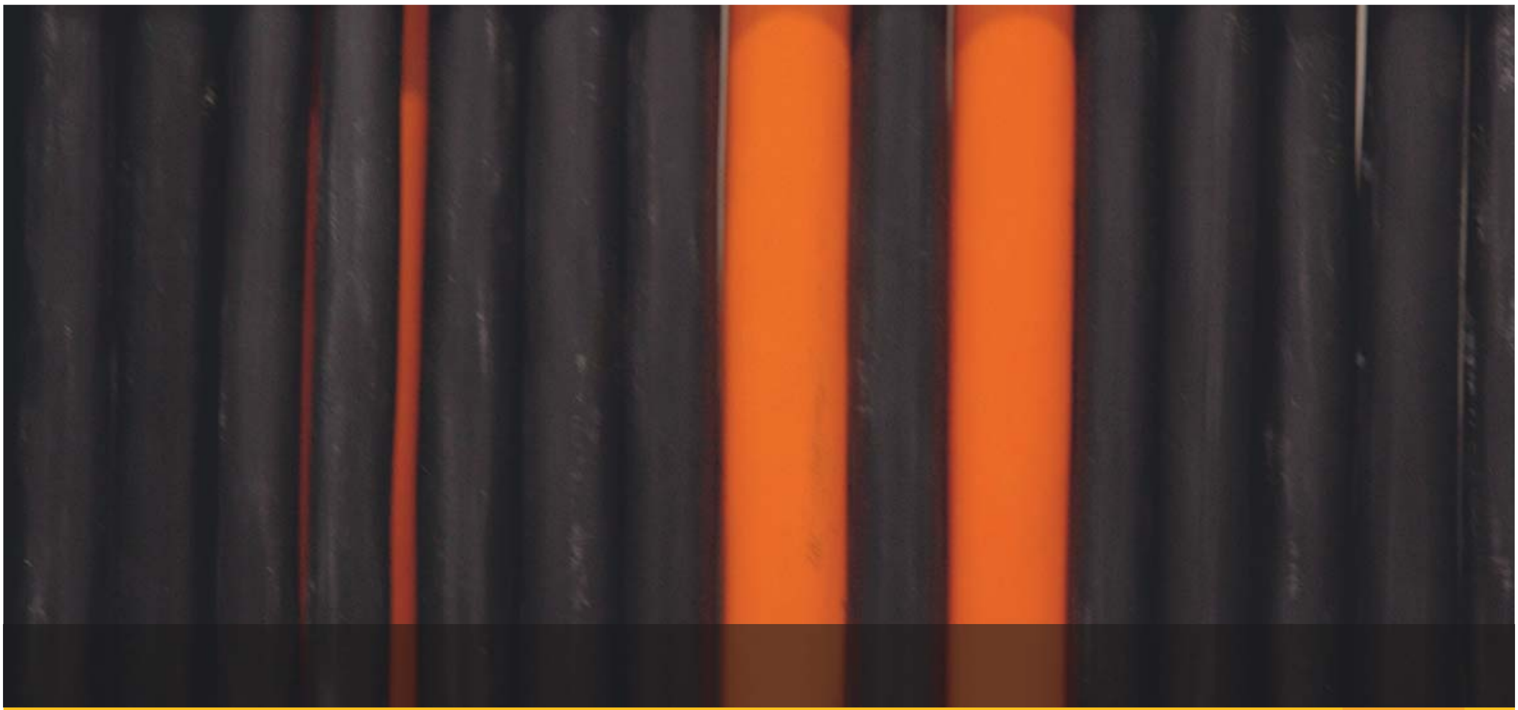
Schedule 6.1.3 requires EnergyAustralia to prepare a pass through clause in respect of the events that should be defined as pass through events for the determination. This clause is attached as Attachment 15.1.

15.9 Conclusion

The Rules define a number of events which cannot be reasonably forecast at the time of the determination, for which a pass through of costs (positive or negative) would apply. In addition to these, EnergyAustralia has identified a number of other material events which could take place during the 2009-14 determination period, where the cost impacts are uncertain.

The pass through events described in this chapter are as follows:

- any material event taking place during the 2004-09 regulatory period which cannot be reflected in the prices for that period (a dead zone event);
- a Force Majeur event;
- a material variance in cost or demand inputs to those assumed at the time of the determination;
- variation in capital expenditure jointly planned with TransGrid or other DNSP;
- changes to compliance obligations;
- the connection of a large customer; and
- costs associated with the separation of EnergyAustralia's Retail business.



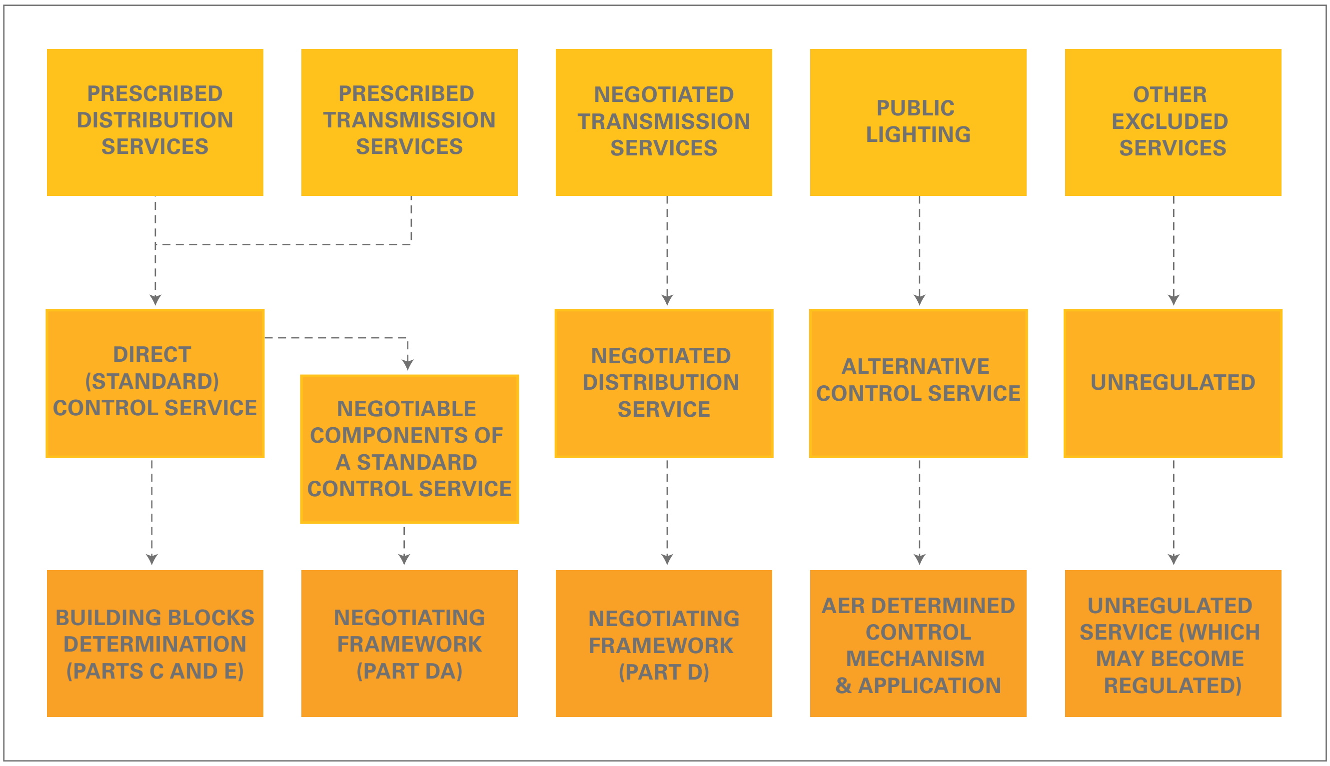
Regulatory Proposal part II

Service Classification and Control Mechanism Proposal June 2008

Contents

1. Service classification

Figure 1.1: Description of service classification



RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(1))

A distribution determination is predicated on a decision on the classification of the services to be provided by the DNSP[1].

In this chapter, EnergyAustralia demonstrates the deemed classifications under the Transitional Rules.

1.1 Classification of services under the rules

Parts A and B of the Rules deem a classification to apply to each of EnergyAustralia's Direct Control Services. The Rules also provide for the AER to vary the deemed classification with the agreement of EnergyAustralia[2].

The deemed classification applied by the Transitional Rules to EnergyAustralia's distribution services is shown diagrammatically in Figure 1.1 and explained further in the remainder of this section.

1.2 Direct (standard) control services

Under Part B of the Transitional Rules, distribution services that IPART previously classified as a prescribed distribution service are deemed to be classified as a Direct Control Service and further classified as a Standard Control Service in the next regulatory control period[3].

In its 2004-09 determination, IPART determined that all distribution services provided by the DNSP, except those listed by the Tribunal as excluded distribution services (see definition of excluded services below), were prescribed distribution services for the purposes of the (then) Code.

In Clause 2.2 of its determination[4], IPART (without limiting the generality of the catch all description of "all distribution services") specifically included the following types of services as prescribed services:

- DUoS services;
- private power line inspections and customer installation inspections;
- Emergency Recoverable Works;
- Monopoly services (ie. those relating to extensions, augmentations or connections to the network that only DNSPs can perform – eg. design checking, installation inspection and energising/de-energising the network) – these are discussed further at Section 1.2.2 below);
- Miscellaneous services (ie. "non-routine" services related to the distribution of electricity, such as meter readings, meter testing and disconnection for non-payment) - these are discussed further at Section 1.2.2 below; and

Consequently each of the above services are now deemed to be classified as Direct Control Services and further classified as Standard Control Services.

1.2.1 Inclusion of EnergyAustralia's transmission network

The Transitional Rules deem EnergyAustralia's transmission support network for the 2009-14 period:

- to be part of its distribution network for the purposes of economic regulation under Chapters 6 and 6A of the Rules;
- to be classified as a Direct Control Service; and
- to be further classified as a Standard Control Service.[5]

Notwithstanding the deemed classification of EnergyAustralia's transmission support network to be distribution Standard Control Services for the purposes of these Transitional Rules, Section 6.1.6(e) notes that Part J of Chapter 6A will apply to the exclusion of Parts I, J and K of the Transitional Rules.

1 Transitional Rule 6.12.1(1)
2 Transitional Rule 6.2.3B(i)
3 Transitional Rule 6.2.3B(a)
4 IPART Determination No2, 2004
5 Transitional Rule 6.1.6(b)

This means that EnergyAustralia's Building Block Proposal includes a revenue requirement in respect of both transmission and distribution network assets, but both the control mechanism and pricing arrangements will be treated separately. This is discussed further in Section 6.

1.2.2 Miscellaneous and monopoly services

Miscellaneous services are 'non-routine' services related to the distribution of electricity. They include special meter readings, meter testing and disconnection for non payment.

Monopoly services are those services only a DNSP can perform related to customer funded extensions, augmentations or connections to the network. For example, when a customer is required to pay for an extension to the network, that is to make a capital contribution, the customer can choose to have the DNSP or an independent ASP perform the work. However, to maintain the safety and integrity of the network, some of the services involved in this work can only be performed by DNSPs. These monopoly services include design checking, installation inspection and energising/de-energising the network.

One addition required to the Miscellaneous and Monopoly Services provided by DNSPs is around defining different disconnection types on customer move-out. When requested to provide a *disconnection at meter box* service by a retailer, EnergyAustralia has historically carried out the disconnection via switching off the main supply and placing a disconnection sticker across the switch.

One retailer in particular has requested that EnergyAustralia disconnect sites via removal of the service fuse. This is more expensive as it requires a second visit by electrically qualified staff to safely carry out the reconnection. Disconnection via turning off the main switch is cheaper, not requiring the return of electrically qualified staff to perform the task.

In response to this market need, EnergyAustralia therefore proposes that the service of *Disconnection at Meter Box*, be broken out in to two types of service:

1. disconnection at meter box via main switch; and
2. disconnection at meter box via fuse removal

By providing distinct disconnection services, the true cost to provide these services can be reflected, improving market efficiency for these services. This will also allow EnergyAustralia to optimise its resources in providing these services and allow retailers to decide what level of service they require, in line with their own cost drivers.

Retailers require disconnection on move out to reduce the financial risk associated with unauthorised energy use. Some retailers prefer a higher level of certainty around the disconnection method to reduce this risk. Attachment 4.2: *Applying the control mechanism to Miscellaneous and Monopoly Charges* details the costs of providing these services for the 2009-14 period.

To put Miscellaneous and Monopoly Services and their associated charges into perspective, the revenue from these services, at approximately $8.5 million in 2006-07, represents about 0.8 percent of total network revenue. The control mechanism associated with Miscellaneous and Monopoly Services is found in Chapter 4.

1.2.3 Negotiable components of direct control services:

EnergyAustralia is required to include in its Regulatory Proposal any Direct Control Services that have negotiable components[6].

Chapter 3 details aspects of distribution service provision which are still 'negotiated' even within Direct Control Services[7]. Negotiable components of a direct control service will be subject to a negotiating framework under Part DA of the Transitional Rules. EnergyAustralia's proposed negotiating framework is addressed in Part III of the Regulatory Proposal.

6 Transitional Rule 6.8.2(c)(8).

7 Transitional Rule 6.2.7A

1.3 Alternative control services.

EnergyAustralia's public lighting services comprise a number of individual business operations that are packaged as a consolidated offering for customers – generally local councils.

In this context, it is important to distinguish the three components of the composite public lighting service:

1. The provision of energy to the public lights (a retail service);
2. The delivery of energy to the public lights (a network service – NUoS); and
3. The construction and maintenance of public lighting assets (street lighting use of system – "SLUoS")

The Transitional Rules deem the construction and maintenance of public lighting to be classified as a Direct Control Service and further classified as an alternative control service[8]. The control mechanism proposed by EnergyAustralia for public lighting services is set out in chapter 7.

1.4 Negotiated distribution services

EnergyAustralia is required to include in its Regulatory Proposal a proposed negotiating framework for negotiated services provided in respect of EnergyAustralia's transmission support network (deemed to be a negotiated distribution service in the Transitional Rules)[9].

This means that any service that (but for the operation of these Transitional Rules) would be classified as negotiated transmission services will be deemed to be negotiated distribution services and subject to the arrangements of Part D of the Transitional Rules[10].

As at June 2008, EnergyAustralia does not provide any Negotiated Distribution Services. There is scope, however, for such services to be provided in the 2009-14 regulatory control period. This is dependant on the agreed network configuration following discussions with the customer once they request a service to be provided.

EnergyAustralia has given detailed consideration to determining whether a service is negotiated. Further detail on EnergyAustralia's approach to classifying and delineating negotiated services from other services can be found in Attachment 1.1 EnergyAustralia's Negotiated Distribution Services.

1.5 Unregulated services

The Transitional Rules deem services previously classified by IPART as excluded services (except for public lighting) to be unregulated services[11]. However, the Excluded Services Rule is still subject to oversight by the AER. Unregulated services can be converted to an alternative control service if the AER forms the view that EnergyAustralia has not substantially complied with the Excluded Services Rule 2004/1[12].

Excluded distribution services which are subject to this classification are:

- customer funded connections (i.e. design and construction of generator funded or customer funded connections);
- works and design and construction of generator funded or customer funded network augmentations;
- customer specific services (i.e. services requested by the customer including asset relocation works, conversion to aerial-bundled cable, temporary, stand-by, reserve or duplicate supplies, and other non-standard, customer requested services); and
- metering services for types 1-4 meters (including meter supply, installation and maintenance, meter reading, meter tests).

EnergyAustralia notes that the Excluded Services Rule will continue to apply in respect of the next regulatory control period as if references to the IPART were references to the AER and references to the regulatory control period 2004-09 were references to the regulatory control period 2009-14, and with any other necessary modifications[13].

Subject to the AER's agreement to EnergyAustralia's proposal to vary the classification of these services (explained in Chapter 2), EnergyAustralia will comply with the Excluded Services Rule during the next regulatory control period.

8 Transitional Rule 6.2.3B(b)(1)

9 Transitional Rule 6.2.7 A

10 Transitional Rule 6.2.7

11 Transitional Rule 6.2.3B(b)(2)

12 Transitional Rules 6.2.3B(c)-(h))

13 Transitional Rule 6.2.3B(d)

2. Seeking agreement to vary the deemed classification of some services

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(1), 6.2.3B(I)

A distribution determination is predicated on a decision on the classification of the services to be provided by the DNSP[14].

The Rules allow the AER to vary the deemed classification of any of the services outlined in Part B of the Transitional Rules, with agreement of the DNSP[15].

In this chapter EnergyAustralia demonstrates:

- why some services classified as excluded should be unclassified and no longer regulated under the Rules; and
- why other services should no longer be classified as a separate service but form part of the basic NUoS service EnergyAustralia provides.

EnergyAustralia also demonstrates why this change in classification is allowed under the Rules.

2.1 Services currently classified as unregulated

The Rules deem services previously classified by IPART as excluded services (except for public lighting) to be unregulated services. EnergyAustralia is required to comply substantially with the Excluded Services Rule 2004/1 in respect of its unregulated services[16].

As noted in Chapter 1, excluded distribution services which are subject to this classification are:

- customer funded connections (i.e. design and construction of generator funded or customer funded connection works and design and construction of generator funded or customer funded network augmentations);
- customer specific services (i.e. services requested by the customer including asset relocation works, conversion to aerial-bundled cable, temporary, stand-by, reserve or duplicate supplies, and other non-standard, customer-requested services); and
- metering services for types 1-4 meters (including meter supply, installation and maintenance, meter reading, meter tests).

While the regulation of unregulated services is relatively "light-handed" the AER may reclassify an unregulated service as an alternative control service if it determines that EnergyAustralia has failed to comply substantially with Excluded Services Rule 2004/01 during the regulatory control period[17].

14 Transitional Rule 6.12.1(1)
15 Transitional Rule 6.2.3B(i)
16 Transitional Rule 6.2.3B(c)
17 Transitional Rule 6.2.3B(e)

The Rules allow the AER to vary the deemed classification of any of the services outlined in Part B of the Transitional Rules, with agreement of the DNSP[18]. In this context "vary" can include removal of the classification altogether so that the service is unclassified. This is supported by the notes to clauses 6.2.3B(b) and (c) which form part of the Rules (see specifically Note 1 to the Transitional Rule 6.2.3B(b) which states "other distribution services provided by a Distribution Network Service Provider are unclassified and not regulated under the Rules"). EnergyAustralia has obtained specific legal advice on this issue which it can provide to the AER if required.

EnergyAustralia proposes that the AER change the deemed classification of unregulated services (services classified as excluded except for public lighting) in the following ways:

2.1.1 Metering services

Services for types 1-4 metering are contestable and should not be regulated. A strong market already exists for these services in EnergyAustralia's network area.

There are six metering providers who actively contest metering provision across the NEM and there has been no evidence of dominance by a particular provider, nor any evidence of collusion to establish dominance.

Notwithstanding that NEMMCO does not publish or make available data which would allow metering providers to establish their market share, the six providers mentioned above are believed to have approximately equal market shares, based upon the observation of transfer statistics.

EnergyAustralia therefore submits that a robust market exists in the provision of types 1-4 meters and that any regulation applied to EnergyAustralia's metering business is not only unnecessary but would potentially act to disadvantage one participant in the market.

2.1.2 Customer funded connections

These services are contestable and in EnergyAustralia's network subject to sufficient competition to render additional regulation of these services unnecessary. Therefore design and construction works specific to the connection should be unclassified.

Customer funded connections are carried out by Accredited Service Providers (ASPs). Currently there are 40 Level 1 ASP companies with 536 authorised employees engaging in contestable subtransmission and distribution construction and 318 Level 2 ASP companies with 426 employees carrying out contestable service line and metering work. EnergyAustralia monitors ASPs compliance with construction standards and safety on an audit basis.

The construction of connection assets has been a contestable activity in NSW since 1998 and the proportion of work carried out by ASPs has progressively increased in recent years. Currently, 75 percent of the connection assets that EnergyAustralia receives are assets designed and constructed by ASPs on behalf of customers (under contestable arrangements)[19]. The remainder are constructed on a competitive basis by EnergyAustralia's construction arm.

The contestable work which is carried out by EnergyAustralia is ring fenced from the regulated functions of EnergyAustralia, in accordance with IPART's requirements.

As with metering types 1-4, EnergyAustralia submits that a robust market exists in the design and construction of connections and that the regulation of EnergyAustralia's contestable construction activities is both unnecessary and potentially damaging.

Contribution of these assets once constructed forms part of the Standard Control Service and Part K of the Transitional Rules applies. Any elements of design of connection works required by EnergyAustralia to best satisfy the connection to the shared network which may be negotiated with the customer would fall under the negotiable components of a Standard Control Service.

18 Transitional Rule 6.2.3B(i)

19 Proportion of provision of assets for 07/08 financial year, Evans and Peck Report, Figure 7.1

2. Seeking agreement to vary the deemed classification of some services (continued)

2.1.3 Customer specific services

"Customer specific services" are essentially an optional service requested by a distribution customer. The two types of service specified in the relevant definition are:

- asset relocation works; and
- conversion to aerial bundled cable.

The IPART definition applied in the Transitional Rules also has a catch all provision relating to any other services relating to the connection of the Distribution Customer to a DNSP's distribution system, the scope of these services are not considered here.

In EnergyAustralia's view no asset relocation works or conversion to aerial bundled cable works undertaken at a person's request (if these works refer to works in relation to a DNSP's own assets) are distribution services as defined under the Rules, where they are requested by a third party (network user or some other person).

It is important to note that a DNSP's own decision to undertake asset relocation works or conversion to aerial bundled cable would be a distribution service (and a Standard Control Service). It is also important to note that if a DNSP undertakes such works on request of a network user, the assets upon completion of the works are contributed and eventually form part of the asset base which provides the distribution service.

The point of issue is that the original request should not be seen as a part of the right of access to the network. The terms and conditions or price of a conversion to aerial bundled cable or relocation works initiated at the request of a network user should not be subject to regulation under an access regime.

Consequently EnergyAustralia submits that the AER either:

(a) notes and confirms that asset relocation works and conversion to aerial bundled cable (made at the request of a person) are not distribution services at all, and hence are not capable of regulation under the Rules; or

(b) in the alternative, if the AER considers that these services are distribution services, decide:

  (i) that such services are only distribution services if they are requested by a network user and only to the extent that they relate to or impact on the network services received by that person; and

  (i) that such services when requested by a person other than a network user are not distribution services.

This would effectively involve the AER noting that as a matter of law:

(i) Asset relocation works and conversion to aerial bundled cable do not fall within the definition of "distribution services";

(ii) Services can only be classified and regulated under the Rules if they fall within the definition of "distribution services";

(iii) The deemed classification under 6.2.3B of the Transitional Rules does not alter this principle (and therefore, despite IPART's previous determination that asset relocation works and conversion to aerial bundled cable were excluded distribution services, and the reference to this in clause 6.2.3B(b), this does not have the legal effect of providing that asset relocation works and conversion to aerial bundled cable are in fact distribution services or of classifying them as excluded services); and

(iv) Therefore, network user or third party requested asset relocation works and conversion to aerial bundled cable, have no classification, are not capable of classification and are not capable of regulation by the AER.

Reasoning: Why asset relocation works and conversion to aerial bundled cable are not distribution services.

Distribution Services are defined under the Rules as:

"A service provided by means of, or in connection with a distribution system".

"By means of" a distribution system: Asset relocation works and conversion to aerial bundled cable are not services provided "by means of" a distribution system. This wording is similar to the wording in Part IIIA of the Trade Practices Act 1974 (Cth) (TPA), which refers to a service provided "by means of a facility". Moving or changing the facility itself (other than, for example, to accommodate a connection) would not in EnergyAustralia's view fall within this definition.

"In connection with" a distribution system: The words "in connection with", are broader and are not contained in the equivalent TPA definition. However, it is difficult to see how a request to move part of the distribution system that is lawfully placed on land is a service provided in connection with the distribution system. These words imply more than that the service is about or somehow related to the distribution system. For example, if a person requested a DNSP to paint its poles pink, this would not be a service "in connection with" the distribution system, simply because the subject matter of the request concerns the distribution system.

Not distribution services: For the above reasons, EnergyAustralia submits that neither asset relocation services, nor conversion to aerial bundled cable (which are of a similar nature), when done at the request of a third party, are "distribution services" as defined by the Rules, whether or not the request is made by a network user.

Distribution customer: Part of IPART's definition was that the services were undertaken at the request of a "Distribution Customer". "Distribution Customer" is defined in the Rules as follows (which is substantially identical to the Code definition at the time of the IPART determination):

"A Customer, Distribution Network Service Provider, Non-Registered Customer or franchise customer having a connection point with a distribution network."

The limitation of the definition of "Customer Specific Services" to those requested by Distribution Customers may have been a reflection of IPART's view of its jurisdictional limitations; for example, that such services would only be "distribution services", and hence capable of regulation by IPART, to the extent that they were provided to Distribution Customers.

Capacity in which the request is made: However, this is a strange distinction in the context of asset relocation works or conversion to aerial bundled cable. For example, many such requests are made by local councils as the distribution assets in question are on council owned or controlled land. The local council will in many cases also be a distribution customer of the DNSP's, but the request is not necessarily made in the council's capacity as a Distribution Customer. For example, it might not relate at all to the service received by the council at its connection point. The request would more usually be made by the council in its capacity as the owner or occupier of the land on which the works are currently located (which could be at a point quite geographically distinct from the council's own connection point). From this point of view, it would seem strange to distinguish between a request made by a landowner who also happens to be a Distribution Customer, and a request made by a landowner who is not. In either case, the request is made by the person in its capacity as landowner, and if the relocation work is performed, the person who made the request is a "customer" for the purpose of the relocation service.

2. Seeking agreement to vary the deemed classification of some services (continued)

Finally, the access implications of something being a "distribution service" is a relevant factor in determining the intended meaning of "distribution service". From a policy point of view it is difficult to see why, for example, a DNSP should be required to move its assets that are lawfully placed on land simply because a person (whether or not a network user) requests the DNSP to do so. The DNSP is in no more a monopoly position in this regard than any other asset owner. With any other asset owner, if a person wishes the owner to move its assets, this would simply be a matter of commercial negotiations, which may or may not result in an agreement to do so. If it does result in an agreement, then it might be said that the asset owner is providing a "service" to the person requesting it, but this does not mean that this is the intended meaning of "service" in the context of an access regime (noting that "services" in such contexts are usually of a more significant or essential nature).

If, contrary to the arguments above, the AER forms the view that such services are distribution services, EnergyAustralia submits that the services are only distribution services to the extent that they are requested by a person who is a network user, and only to the extent that they relate to or impact upon the network services received by that network user. If they are requested by a person who is not a network user, they are not distribution services.

2.2 Emergency recoverable works

EnergyAustralia has analysed whether Emergency Recoverable Works are distribution services provided by a DNSP and has concluded that they are not such services.

EnergyAustralia therefore proposes that the AER either:

(a) notes and confirms that Emergency Recoverable Works are not distribution services at all, and hence are not capable of regulation under the Rules; or

(b) in the alternative, if the AER considers that Emergency Recoverable Works are distribution services, decides that the deemed classification which applies to those services by virtue of clause 6.2.3B of the Transitional Rules be varied so that the services are unclassified and hence not regulated under the Rules.

EnergyAustralia's preference is (a), as EnergyAustralia believes that this is the legally correct view. EnergyAustralia's analysis and reasoning to support this proposal are set out in Attachment 2.1 – Variation of Classification of Emergency Recoverable Works.

Option (a) would effectively involve the AER noting that, as a matter of law:

(i) Emergency Recoverable Works do not fall within the definition of "distribution services";

(ii) services can only be classified and regulated under the Rules if they fall within the definition of "distribution services";

(iii) the deemed classification under clause 6.2.3B of the Transitional Rules does not alter this principle (and therefore, despite IPART's previous determination that Emergency Recoverable Works were Prescribed Distribution Services, and the reference to this in clause 6.2.3B(a), this does not have the legal effect of providing that Emergency Recoverable Works are in fact distribution services or of classifying them as Standard Control Services); and

(iv) therefore, Emergency Recoverable Works are not distribution services, have no classification, are not capable of classification and are not capable of regulation by the AER."

3. Negotiable components of Direct Control Services

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(16A))

The AER's distribution determination is predicated on a decision in which the AER decides which, if any, components of Direct Control Services are negotiable components[20].

In this chapter, EnergyAustralia demonstrates those components of its overall direct service provision which are negotiable components.

3.1 Negotiable components of standard control services

The provision of all distribution services under an access regime needs to be seen in the context of access to a network which involves customers and networks settling on price and non-price terms and conditions.

In this context, Part L of Chapter 6 establishes that there may be access disputes as an enforcement mechanism in respect of all Direct Control and Negotiated Distribution Services. These access disputes are determined by the AER under Part 10 of the NEL and Part L of the Transitional Rules and may involve questions of price and non price aspects of access.

In most circumstances access disputes with respect to Direct Control Services will be determined by applying the AER's determination on revenue and pricing (for price aspects) or by applying (as relevant) Chapters 4,5, 6 and 7 of the Rules and any other applicable regulatory instruments (for non-price terms and conditions). However, where applicable regulatory instruments allow for some form of negotiation between customer and service provider, the Rules require that negotiation, be subject to a negotiating framework.

Consequently EnergyAustralia is now required to include in its Regulatory Proposal any (and if so which) components of Direct Control Services should be negotiable components[21].

Negotiable components of a Direct Control Service will be subject to a negotiating framework under Part DA of the Transitional Rules.

While negotiation may occur as part of any connection, in reality the number of circumstances in which negotiation does occur is extremely small and the negotiated aspect of that negotiated service is usually minor in nature.

Many of the conditions for these services are regulated in separate jurisdictional instruments. However, at the margin there is scope for negotiation of the service provided. It would be very difficult to excise the "negotiable" part of the service from the rest of the service provided. Similarly, there would be uncertainty if a framework did not allow a negotiation framework to apply in these instances merely because the service is not characterised as such.

EnergyAustralia's proposed approach to describing the negotiable components of Direct Control Services will be based on a set of criteria against which the component can be tested and will include an indicative list. The proposed criteria is as follows:

A negotiable component of a Direct Control Service will be any component of that service (or a condition of the service) where some variability can be applied to the provision of the Direct Control Service without interfering with or in any way compromising EnergyAustralia's ability to comply with any regulatory obligation or requirement as that term is defined in the National Electricity Law and may include the following types of matters:

- *location of substation to support customer load;*
- *location of customer's connection to network and point of entry to the premises, and location of metering*
- *voltage level of customer's connection;*
- *assessment of customers load requirement;*
- *availability of standby supply from the EnergyAustralia grid when on-site generation unavailable;*
- *capacity of customer's connection before augmentation or other works will be required; and*
- *design planning criteria which exceeds the applicable security standard.*

20 Transitional Rule 6.12.1(16A)

21 Transitional Rule 6.8.2(c)(8)

3. Negotiable components of Direct Control Services (continued)

This is consistent with Section 6.1.3 of the Transitional Rules which requires the DNSP to provide Direct Control Services on terms and conditions consistent with Chapters 4-7 of the Rules and the provisions of Part DA of the Transitional Rules. EnergyAustralia's approach will allow flexibility to negotiate terms and conditions where the Rules allow.

3.1.1 Explanation of negotiable components in the context of connections

The most common example of Direct Control Services which will have a negotiable component is for connection service. There are many instances where the initial connection to the shared network may involve negotiation of sorts at the margin for the service provided. This negotiation arrangement lasts only for the period of connection.

Once connected most assets operate and are maintained no differently from other parts of the shared network.

The process of connecting a new customer or generator ("user") may involve:

- the DNSP undertaking technical studies to assess the suitability of the connection (at the user's cost);
- information exchange between the DNSP and the user regarding which new assets will be constructed to accommodate the connection and which of those assets are to be funded by the user;
- establishment of the various commercial and technical aspects of the connection agreement (which may involve aspects of negotiation);
- the DNSP preparing a design brief for new assets to be constructed (at the user's cost);
- design and construction of new capital works (at the user's cost) by an ASP (for contestable works) or the DNSP (for certain works that are non-contestable for reasons of safety or security);
- design and construction of new capital works (at the DNSP's cost) by the DNSP; and
- allowing the user to import and export power to and from the distribution system via existing and new assets (once the new assets are commissioned)[22].

A user, upon connection, effectively does not see a series of different services, but one connection service.

However, there is a complex layering of services before connection is provided.

For example, the preparation of the design brief is a monopoly service. The design and construction of assets is a contestable service. However, both of these services are essentially conditions of connection.

The regulatory framework separates contestable from non-contestable services but at the margin will allow for discussions around some parts of this overall connection. This will necessarily be done in the context of EnergyAustralia's obligations to all network customers. There is no negotiation around a requested service which threatens the reliability, safety or security for all network customers.

Therefore discussions (in terms of the process mentioned above) cross various aspects of connection, such as on the commercial terms and conditions would often benefit from a negotiating framework.

In summary it is important to note that:

- while negotiations can occur with a broad spectrum of services they are likely only to apply to a small number of circumstances;
- of those circumstances only a small element of the total service is likely to be the negotiable component; and
- the precise nature, timing or quantum of total services is uncertain and likely to vary.

22 Transitional Rule 6.1.4 requires precludes a DSNP from charging customers for the export of energy but does not preclude charges associated with connection.

3.1.2 Other examples of standard control services which may have negotiable components

The scope of negotiable services within the existing shared network is even more difficult to define but is expected to be limited.

The most obvious negotiable component of the use of system service would be where the customer is seeking a level of security or reliability that exceeds that which would ordinarily apply to that customer's point of supply.

Clause 6.7A.1 (8) of the Transitional Rules contemplates that negotiated services will include those which are the subject of access charges negotiated under clause 5.5(f)(4)(ii) and (iii) of the Rules (relating to financially firm access and negotiated compensation for constraint). Similarly, see clause 6.7.4(a) (1) (ii).

Transitional Rule 6.7A.1 (8) states that negotiated services will include those the subject of access charges negotiated under clause 5.5(f)(4)(ii) and (iii) of the Rules (relating to financially firm access and negotiated compensation for constraint). Similarly, see Transitional Rule 6.7.4(a) (1) (ii).

There are a number of difficulties in applying clause 5.5(f)(4)(ii) and (iii) of the Rules. There are ambiguities regarding what constitutes the "standard" level of service for generators. It is also difficult to pin-point what constitutes an "above-standard" service under Chapter 5.

3.2 Negotiable components in respect of public lighting

Clause 2.3(g) of IPART's Excluded Service Rule notes that the control mechanisms and regulatory arrangements applying to charges for the construction and maintenance of public lighting do not apply where:

- an agreement is the result of negotiations only between the DNSP and the public lighting infrastructure customer; and
- the agreement applies only to the construction and maintenance of public lighting infrastructure.

While the form of control is ultimately determined by the AER as part of a distribution determination, EnergyAustralia submits that a negotiable component of Direct Control Services should extend to the negotiable components of alternative control services to the extent that the AER's determination on control mechanisms and approach allow.

4. Control mechanism for Standard Control (DUoS) Services

In this section EnergyAustralia demonstrates:

- the control mechanism that applies to each separate category of Standard Control Service; and
- how the control mechanism will apply differently for different services.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(11))

A distribution determination is predicated on a decision on the control mechanism (including the X factor) for Standard Control Services.

4.1 Control mechanism for standard control services

The Rules require that the control mechanism for EnergyAustralia's Standard Control Services (with the exception of its transmission related Standard Control Services) should be substantially the same as that determined by IPART for the corresponding prescribed distribution services in the current regulatory control period[23].

In 2004, IPART determined that EnergyAustralia's DUoS Tariffs, miscellaneous charges and monopoly services and charges for recoverable works for emergency services were prescribed distribution services.

The AER has produced guidelines aimed at applying formulas for Standard Control Services that are consistent with the formula applied in IPART's determination.

In summary, the AER's guidelines propose the following control mechanism apply to the 2009-14 regulatory control period.

- a WAPC for the distribution component of network prices;
- a pass through of the transmission components of network prices; and
- a schedule of fees and/or charges for specific Miscellaneous and Monopoly Services and Emergency Recoverable Works within the WAPC.

EnergyAustralia has reviewed the guidelines and has prepared its control mechanism in accordance with that guideline with a minor variation in the case of the treatment of miscellaneous fees and monopoly charges.

4.2 Application of a weighted average price cap

The WAPC is a control mechanism that controls price, rather than revenue. Tariffs are constrained in how much they can vary in any given year, on a weighted average basis, without consideration of forecast volumes.

- If volumes rise above those anticipated at the time of setting the X factors, then EnergyAustralia can expect above forecast revenues.
- Similarly, if volumes fall below that anticipated, EnergyAustralia can expect below forecast revenues.

These expected volume/revenue considerations apply to each component of each distribution network tariff.

The following sections outline some more detailed aspects surrounding the application of the control mechanism as noted in the AER's guideline.

4.2.1 IPART approach to setting WAPC

The application of a WAPC consistent with the AER's guideline and similar to the IPART approach is as follows:

- after establishing the annual revenue requirement, a smoothing exercise is carried out and a set of X factors is derived for each year of the regulatory period. The smoothing and X factors are derived using the forecast consumption of each tariff component over the regulatory period;
- the X factors thereby form the basis for the CPI – X form of constraint on weighted average price increases;
- each year (year t-1), the WAPC formula is used to determine prices for the year ahead (year t). The DNSP is required to submit prices which are compliant with the WAPC formula, for approval by the regulator;
- to execute the WAPC, each proposed tariff component is weighted against historic volumes (in year t-2). The notional revenue sums using this volume and prices for years t-1 and t reflect the proportional increase in proposed prices against current prices; and

23 Transitional Rule 6.2.5(c1)(1) The control mechanism adopted by IPART previously was consistent with Transitional Rule 6.2.6(a)

- the change in revenue sum from this calculation must be less than or equal to CPI – X + D for the relevant year. The D variable relates the D factor incentive, which is discussed further below.

4.2.2 Timing in setting volumes

The volumes for the WAPC are reported from billed volumes in late November to early December each year, rather than those reported at the time of the Regulatory Accounts in August.

The reporting is deliberately carried out later to allow for billing related to the previous financial year to finalise. If volumes were reported closer to the completion of the financial year with the Regulatory Accounts in August, approximately half of the quarterly read accounts would not have completed their billing cycle. Reporting of actual billing would heavily skew the volumes to monthly billed business tariffs, creating perverse outcomes in setting prices using those volumes. Thus, an estimate (accrual) of the unbilled volumes and revenue would be required.

Alternatively, the DNSP could propose an accrual method at a tariff level to estimate the unbilled quarterly volumes, but these accrual estimates have proven in practice to be quite inaccurate. At a tariff component level of granularity, there is great uncertainty and the volumes cannot be 'audited' by an independent party. The use of an accrual method at a tariff level to report on energy volume estimates would be subject to extensive dispute since it would have a material impact on price outcomes from application of the WAPC.

It is proposed that for during the 2009-14 regulatory period, the same timing and reporting of tariff volumes for the WAPC established by IPART be applied by the AER:

1. Volumes of billed tariff component quantities to be established in late November to early December (year t-2);
2. EnergyAustralia to seek a negative assurance review by an independent party on the accuracy of the volumes in early January; and
3. EnergyAustralia provide the assurance advice together with the volumes to the AER in mid March for review and approval, before prices are set using thoses quantities.

4.2.3 Reasonable estimates

IPART's application of the WAPC accounted for new tariffs and expected transfers of customers from one tariff to another using "reasonable estimates".

Reasonable estimates involve estimation of the expected future volume 'creation' from new tariffs or mandated movements between tariffs. These reasonable estimates are applied as adjustments to the historic t-2 quantities used in the WAPC.

The rationale of this mechanism is that the DNSP should remain effectively revenue neutral if it proposes to move customers between two differently priced tariffs. This has been a consideration for EnergyAustralia, particularly in relation to moving customers from obsolete tariffs to new tariffs where metering has been upgraded.

If no reasonable estimate mechanism was in place, any proposed future tariff transfers would potentially create revenue gains or losses for the DNSP, since the WAPC is based on historic volumes.

The Rules surrounding tariff transfers are discussed further in the Pricing and Negotiating Frameworks Proposal (Part III).

Further details on the application of the control mechanism for Standard Control Services are found in the Building Block Proposal (Part I).

Finally a more detailed demonstration of the WAPC calculation can be found in Attachment 4.1 – EnergyAustralia's Calculation of the Weighted Average Price Cap.

4.2.4 Adjustment to control mechanism during the regulatory control period

During the 2009-14 regulatory control period, adjustments are to be made:

- as an increment or decrement to the annual revenue requirement (which will follow through to the control mechanism and prices to customers) as required by the Rules[24];

24 Transitional Rule 6.4.3

- directly to the control mechanism (which will follow through to prices to customers) as a result of an increment or decrement to the annual revenue requirement required by the Rules[25]; or
- separate to the control mechanism but incorporated in the DUoS charges to customers.

Increments and decrements:

Transitional Rule 6.4.3 notes that building blocks include several increments and decrements:

- arising from the application of the Demand Management Incentive Scheme (DMIS) and Service Target Performance Incentive Scheme (STPIS); or
- other increments/decrements arising from the application of the control mechanism from the previous period.

In respect of DMIS, the approach taken by the AER in implementing the DMIS to NSW businesses is consistent with IPART's approach in the current determination. This means that adjustments relating to the application of the D factor arrangements in the current regulatory control period or the DMIS in the next period are made directly to the control mechanism (explained below). Therefore, there are no increments and decrements to the annual revenue requirement flowing from the application of DMIS in the next regulatory control period.

In respect of STPIS, there will be no revenue implications arising from the application of STPIS in this period. Increments and decrements are therefore limited to the carry-over of the STPIS for transmission.

Nevertheless, EnergyAustralia has identified that increments and decrements to the annual revenue requirement would be triggered as a result of an approved pass through amount.

As noted in our Building Block Proposal, approved costs associated with pass through events under Transitional Rule 6.6 will adjust the annual revenue requirement for each relevant year.

A pass through event may involve costs associated with our distribution network, transmission network, or both.

Where the pass through event relates to the provision of **distribution** control services, it is proposed that adjustments to the annual revenue requirement be treated separately to the control mechanism established at the beginning of the period. This is consistent with the current approach under the IPART framework[26], where revenue recovery of pass through events is carried out through what might be described as a "one shot revenue cap". The one shot revenue cap acts independently of the WAPC.

It is proposed that the same mechanism be adopted for the 2009-14 regulatory period, consistent with the current IPART framework.

Under this approach, the adjustment to the annual revenue requirement associated with the approved pass though is not included in the standard calculation of the control mechanism. Instead, using a separate control mechanism prices for any given year are allocated a portion of the additional revenue requirement based on the most recently audited financial year's billed quantities (Q(t-2) volumes)[27].

To achieve approved pass through costs for a given year t prices P(f) are therefore set based on:

Notional Revenue for Year(t) = P(t) x Q(t-2)

Historic billed quantities are used as a proxy for forecast quantities. Real revenues of course will be delivered through Q(t) volume[28]. Under this approach, there is more likelihood of EnergyAustralia being able to recover (only) the costs associated with the pass through event.

Such an arrangement also reduces regulatory oversight, and is generally in keeping with the principle of volume risk inherent in the price cap.

25 ibid

26 IPART Final Report on NSW Electricty Distribution Pricing 2004/05 to 2008/09, p132 cl 11.3.4

27 It should be noted that while IPART proposed the use of forecast quantities Q(t) to base prices on (consistent with price setting for transmission cost recovery), this was not reflected in the determination document, and IPART decided to use Q(t-1) in their compliance model.

28 Consistent with the Transitional Rules, year t is the next upcoming regulatory year, year t-1 is the current regulatory year, and year t-2 is the most recently completed regulatory year.

By having a separate control mechanism to the WAPC, price components for distribution pass through events can be explicitly identified. Explicit identification allows for the ready exclusion of those components when assessing compliance to tariff side constraints, as required by the Transitional Rules[29].

Where the pass through event relates to the provision of **transmission** control services, it is proposed that any adjustments be treated consistent with the AER guidelines[30].

That is, approved pass through costs will act as a simple adjustment to the the Maximum Allowable Revenue (MAR) for the relevant regulatory year.

Carry-over of the Service Performance Incentive Scheme from 2004-09 for transmission is proposed consistent with the AER Guidelines[31]. Performance under the scheme for the calendar year 2008 will be applied through adjustments to the MAR for 2009-10. For the calendar year 2009, the scheme will only apply for the first six months, so it is proposed that the relevant MAR for the second six months be set to zero, and the resulting figure apply as an adjustment to the MAR for 2010/11. This is consistent with the AER guidelines. No other carry-over in to 2009-14 is required, as adjustments to the transmission revenue path X factors. It is not anticipated that price components related to the pass though costs would need to be explicitly identified, as is the case with distribution pass through.

Where an adjustment due to pass through relates to both transmission and distribution networks (for example, a service standard event impacting both), allocation of the increment/decrement to distribution and transmission control services is proposed, based on the Cost Allocation Methodology approved by the AER.

Adjustments directly to the control mechanism

X factors determined at the beginning of the regulatory control period in accordance with Transitional Rule 6.5.9 are adjusted on a yearly basis to reflect the following mechanisms required under the Rules:

- D Factor;
- DM Innovation Fund; and
- any other incentive mechanism.

These adjustments, when applied to the X factors established at the time of the determination, represent the CPI – X limitation referred to in Part I of the Transitional Rules (including Transitional Rule 6.18.6).

This is consistent with the AER guidelines where the CPI – X formula is modified by other adjustments factors, such as the D factor, such that[32]:

Weighted Average Price Increase $\leq$ CPI – X + D Factor

It is proposed that to maintain consistency with the tariff side constraint formula, that the CPI – X formula, thus modified for any incentive mechanisms becomes:

$\text{CPI} - \text{X} + \text{D Factor} = \text{CPI} - \text{X}_{\text{ADJ}}$

That is, the CPI – X formula is modified to derive a new CPI – X, which has relevant adjustments embedded within it. The CPI – X_{ADJ} is then applied to the weighted average price cap, and used in the 1 + ΔCPI + L side constraint formula[33] on DUoS tariffs. This approach is consistent with the Rules and the AER Guidelines, and allows for appropriate pass through of costs related to any incentive mechanism proposed by the AER without being inappropriately constrained by the tariff side constraints.

In the absence of this approach, any increases from an incentive mechanism would need to be accommodated within the side constraints. This may potentially constrain revenues that the DNSP is entitled to recover.

29 Transitional Rules 6.18.6(d)(1)

30 AER Guideline on Control Mechanisms for Direct Control Services for ACT and NSW 2009 distribution services, February 2008, Clause 2.2

31 ibid

32 ibid, clause 2.3.1, p9: "The AER may allow adjustments to this formula to recognise any demand management incentives and/or service target performance incentives".

33 ibid, Appendix A: Side Constraints, p10

4. Control mechanism for Standard Control (DUoS) Services (continued)

This approach ensures that these adjustments can be made to the basic CPI-X control mechanism for DUoS services so that each year the control mechanism is consistent with what is established in the current period.

In determining adjustments to the CPI – X formula during the regulatory control period, it is also proposed that the method currently used in determining the D factor be applied[34].

Like the current approach for D factor conversion, any revenue figure adjustment would be converted to a percent adjustment to the CPI – X formula on the same basis that is used for the D factor conversion.

The carry forward of the D factor from the 2004-09 regulatory period to the 2009-14 period will be done consistently with the current application of the D factor. Approved revenue recovery under the D factor from year t-2, will be applied to the control mechanism in year t. As such, approved revenues from 2007-08, will be applied to the control mechanism for setting prices for year 2009-10. Similarly year 2008-09 will be applied in year 2010-11.

Adjustments outside the control mechanism

With respect to EnergyAustralia as a DNSP, charges related with TUoS services are proposed to be recovered consistent with the AERs guidelines[35], and as detailed in the Pricing and Negotiating Framework part of this proposal[36].

In NSW, each DNSP is required to contribute to the Climate Change Fund, as administered by the NSW Department of Water and Energy. Recovery of costs associated with this fund is done through a levy on DUoS tariffs. Recovery of this levy is not related to the provision of Standard Control Services, and therefore falls outside of the control mechanism for these services. Any other levy or tax imposed by the state or commonwealth government will likewise fall outside the control mechanism. It is proposed that the Climate Change Fund, and any other tax or levy will be recovered using the same mechanism as applied to recovery of transmission cost recovery tariffs.

4.2.5 Application of side constraints

The AER will be aware of the consequence of having inappropriate structures and levels associated with side constraints, as demonstrated by the IPART price approval process in 2008. The side constraint of IPART's determination was required to be varied, to permit unanticipated transmission cost increases to be passed through.

EnergyAustralia is therefore keen to ensure that, whilst the consumer protection features of a side constraint regime are retained, necessary cost changes can be passed through at the time they are incurred.

While not specifically part of the control mechanism, the Rules establish side constraints which are to apply to the DUoS component of tariffs, restricting the movement of any given tariff by CPI – X + 2 percent. The side constraint formulation is in essence a simplified version of the WAPC formula, but applying to each tariff rather than to individual tariff components.

EnergyAustralia proposes the application of the side constraint mechanism consistent with the AER Guidelines[37].

It should be noted that the Climate Change Fund, together with any other tax and levy are not included in the calculation of the movement in weighted average revenue for standard control services[38].

34 IPART Determination No 2, 2004, Clause 11.3 Calculation of D factor

35 AER Guidelines for Control Mechanisms for Direct Control Services for the ACT and NSW 2009 distribution determinations, Appendix B, February 2008: Transmission Cost Recovery Tariffs

36 Part III: Pricing & Negotiating Framework, Chapter 3: Treatment of TUoS Recovery in Distribution Pricing.

37 AER Guidelines for Control Mechanisms for Direct Control Services for the ACT and NSW 2009 distribution determinations: Appendix A, February 2008.

38 Transitional Rule, clause 6.18.6(a)

However, any other incentive mechanism proposed by the AER will not be excluded in assessing compliance with the side constraints, but would be accounted for as an adjustment to the CPI – X formula, consistent with the AER guidelines, and this adjusted CPI – X formula would be used to apply the side constraint formula detailed in the Rules[39]. This would be consistent with the WAPC control mechanism.

4.2.6 Control mechanism for standard control (miscellaneous and monopoly services)

IPART has considered Miscellaneous and Monopoly Services to be part of the monopoly business (termed "Prescribed Services") and the cost of their provision included in the regulated price path.

The revenue attributed to Miscellaneous and Monopoly Services is currently dealt with in pricing as an adjustment to the allowed revenue under the WAPC. These services are effectively regulated as though a price component, but IPART determined in 2004 that the maximum price would not vary over the period.

The AER's guidelines adopt a similar approach where they determine a schedule of fees and/or charges for specific Miscellaneous Services, Monopoly Services and Emergency Recoverable Works. These charges are fixed for the period.

However, to cater for the emergence of new and altered services during the period of the determination, EnergyAustralia is proposing that Miscellaneous and Monopoly Services be considered as elements of the WAPC in the same way as tariffs for the use of the network. This would include Miscellaneous and Monopoly Services being subject to the pricing side constraint and would permit the introduction of new Miscellaneous and Monopoly components, subject to the same reasonable estimates provisions as network tariffs and AER approval.

Details on EnergyAustralia's proposed calculation of Miscellaneous and Monopoly Charges and explanation of this calculation is provided in Attachment 13.1 *Applying the control mechanism to Miscellaneous and Monopoly Services*.

39 Transitional Rule, clause 6.18.6(c)(1)

5. Control mechanism for standard control (TUoS) services

In this section EnergyAustralia demonstrates the control mechanism for its transmission support network and how it complies with the Rules.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.2.5(c1))

The Rules require the control mechanism for EnergyAustralia's prescribed (Transmission) services to be substantially the same as that determined by the ACCC for the corresponding Prescribed Transmission Services provided in the 2004-09 regulatory control period[40].

The ACCC determination applied a revenue cap control mechanism to EnergyAustralia's transmission business, consistent with the Code at that time and the AER's own Statement of Regulatory Principles.

The ACCC noted in its determination that its role under the Code was limited to:

- determining annual revenue, using an accrual building block assessment of the underlying costs of the business;
- deriving an unsmoothed revenue trajectory;
- calculating a smoothed revenue trajectory for the years of the regulatory control period; and
- converting that smoothed revenue requirement to a maximum allowed revenue.

As the maximum annual revenue will be determined by the Annual Revenue Requirement established under the Transitional Rules, EnergyAustralia proposes each year to establish the revenue to be recovered through tariffs, consistent with the formula in the ACCC determination and the requirements of Transitional Rule 6.5.9:

$$MAR = AR_t + [(AR_{t-1} + AR_{t-2})/2 \times S_{ct}] \pm \text{pass through}$$

where $AR_t = AR_{t-1} \times (1 + CPI) \times (1 - X)$

where:

AR = annual revenue

t = time period/financial year

ct = calendar year t

S = service standards factor

CPI = actual CPI

X = smoothing factor

For the 2009-14 regulatory control period, the "S" adjustment reflects the carry over of adjustments arising from the application of the Service Target Performance Incentive Scheme for transmission in the current regulatory control period.

This approach is consistent with that adopted by the AER in Section 2.2 of its guideline on the control mechanism for Standard Control Services.

Based on this formula and the application of the control mechanism in accordance with the previous ACCC determination, the MAR that will apply to EnergyAustralia's transmission network is as follows:

Table 5.1: Maximum allowed revenue ($m nominal)

	FY10	FY11	FY12	FY13	FY14
Unsmoothed MAR	143.93	178.92	204.06	238.23	276.50
Smoothed MAR	**143.93**	**170.87**	**202.83**	**240.78**	**285.84**

Details of EnergyAustralia's calculation of the MAR for the transmission business is found in Part I Attachment 1.1: Post Tax Revenue Model (PTRM).

5.1 Administration of overs/unders

It is proposed that the current revenue cap mechanism for the transmission business be maintained.

40 Transitional Rules 6.2.5(c1)

6. Division of revenue between transmission and distribution

In this section EnergyAustralia demonstrates:

- how revenue is apportioned into distribution and transmission components; and
- the link between this apportionment, the X factor, and the building blocks proposal.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1A)

The Rules require that the AER divide EnergyAustralia's revenue calculated under Part C of the rules into the following two portions[41]:

- A portion relevant to EnergyAustralia's Prescribed (Transmission) Standard Control Services; and
- A portion relevant to other Standard Control Services provided by EnergyAustralia.

Based on EnergyAustralia's approved cost allocation methodology.

6.1 EnergyAustralia's approach to apportioning revenue between transmission and distribution components

The Transitional Rules do not distinguish between transmission and distribution network assets for the purposes of determining the annual revenue requirement. Therefore, there is no need for the continuance of separate roll forward models for the distribution and transmission parts of EnergyAustralia's business.

Nevertheless, in order to divide revenues into respective portions for pricing purposes, the Rules indicate the following transitional arrangements:

- the opening RAB is established in accordance with Schedule 6.2 using the models of IPART and the ACCC respectively to arrive at an opening RAB value for all Standard Control Services in 2009;
- the annual revenue requirement for Standard Control Services will be based on both transmission and distribution components and determined in accordance with Transitional Rule 6.3.2;
- the AER will impose controls on Standard Control Services in a manner which is substantially the same as that which currently applies under the existing IPART and ACCC determinations[42];
- the AER must then divide the Aggregate Annual Revenue Requirement (AARR) between Standard Control Distribution and Transmission Services[43]. This apportionment will be based on EnergyAustralia's approved cost allocation method; and
- pricing rules for transmission and distribution will be subject to the appropriate provisions in Part J of Chapter 6A and Part I of Chapter 6 respectively.

EnergyAustralia's approach in respect of this has been to modify the PTRM to cater for derivation of separate revenue amounts for the transmission and distribution network.

Essentially this has involved developing separate PTRM models for transmission and distribution networks, the inputs of which represent costs and assets directly attributable to transmission or distribution or otherwise allocated in accordance with the cost allocation methodology. The revenue build up of both the transmission and distribution amounts is reconciled to the revenue requirement for all Standard Control Services.

Details of this approach are found in EnergyAustralia's completed PTRM.

6.2 Transfer of assets between transmission and distribution categories

EnergyAustralia plans, maintains and operates its network as a single business. From a technical perspective however, the Rules categorise some of EnergyAustralia's assets as transmission and many assets will move in and out of that category over time. Over the 2004-09 period, a number of assets have changed classification between transmission and distribution.

41 Transitional Rule 6.12.1A

42 Transitional Rule 6.2.5(c1)

43 Transitional Rule 6.12.1A(a)

6. Division of revenue between transmission and distribution (continued)

As a result of the changing classification of assets, the RABs for the two businesses must be adjusted, and the basis for allocating shared costs must be recalculated.

Consistent with the approach in the last determination, EnergyAustralia proposes that the "reclassification" of such assets occur between regulatory control periods (ie at the time of establishing the regulatory asset base at the beginning of the next regulatory control period) rather than within a regulatory control period.

6.3 Allocation of costs between transmission and distribution categories

Historically, EnergyAustralia has allocated costs shared by the distribution and transmission businesses using an allocation based on the relative asset values of the distribution and transmission RABs. As the RABs for distribution and transmission would have changed during the 2004-09 period, the relative asset values, and therefore the basis (percentage) used for allocation of shared costs will also change.

To allocate the network costs between prescribed transmission and distribution services, EnergyAustralia has applied the same allocation approach as that approved by the ACCC in its 2004-09 determination, and as subsequently used for annual regulatory reporting over the current regulatory period.

Where possible, EnergyAustralia attributes system operating expenditure to the assets that are directly linked to the provision of distribution and transmission services. The contribution of system operating costs to identifiable transmission assets for each cost category is calculated in percentage terms. This relationship of causality is then applied in fixed proportions over the course of the regulatory control period.

Non-system operating expenditure does not share the same causal relationship to asset categories. EnergyAustralia therefore establishes a percentage allocation for shared costs so that they can be allocated between the distribution and transmission businesses for pricing purposes. The allocation is based on the relative proportions of distribution and transmission assets to the total RAB and also remains fixed for the regulatory control period.

Note that this allocation has been calculated after assets have been transferred from the distribution RAB to the transmission RAB as a result of their function changing as per the definition for transmission assets in Chapter 10 of the Rules.

Further details of the allocation method are found in Attachment 6.1: EnergyAustralia's Cost Allocation Method.

7. Control mechanism for public lighting services

In this section EnergyAustralia demonstrates:

- the control mechanism that is proposed to apply for its public lighting services for the 2009-14 regulatory control period;
- how compliance with the relevant control mechanism will be demonstrated; and
- a justification of the extent to which EnergyAustralia has departed from the AER statement on the likely approach to the control mechanisms for alternative control services.

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(11))

The AER's distribution determination is predicated on a decision on the control mechanism for public lighting services and a decision on how compliance with a relevant control mechanism is to be demonstrated.[44]

Clause 6.8.2(3A)(i) of the Transitional Rules requires that EnergyAustralia's public lighting proposal must contain the following details:

- the proposed control mechanism;
- a demonstration of the application of the proposed control mechanism; and
- the necessary supporting information.

7.1 Overview of public lighting services

Approximately 100 customers (including 41 councils) representing over three million people rely on public lighting services from EnergyAustralia. In addition to the local councils, some of our other public lighting customers include community associations, recreational clubs and the NSW Roads and Traffic Authority. The area serviced by the business stretches from the Sutherland Shire to the Hunter region of NSW. This area is the same as the EnergyAustralia's distribution network area. Our public lighting assets include approximately 245,000 public lights, or 1.24 million individual components. Our public lighting services consist of a 24 hour enquiry and fault reporting service, asset design, and an installation and maintenance operation.

7.2 Considerations in determining a control mechanism for public lighting

As noted in Section 1.3, the Transitional Rules deem EnergyAustralia's public lighting services to be classified as an alternative control service for the 2009-14 regulatory control period.

Transitional Rule 6.2.5(c2) states that the control mechanism for EnergyAustralia's public lighting service may consist of:

(1) A schedule of fixed prices;
(2) Caps on the prices of individual services;
(3) Caps on the revenue to be derived from a particular combination of services;
(4) Tariff basket;
(5) Revenue yield; or
(6) A combination of any of the above.

In deciding which of these control mechanisms is appropriate for public lighting services, the AER must have regard to the provisions of Transitional Rule 6.2.5(d) of the Transitional Rules:

(1) The potential for development of competition in the relevant market and how the control mechanism might influence that potential;
(2) The possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users;
(3) The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination;
(4) The desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
(5) Any other relevant factor.

44 Transitional Rule 6.12.1(11)

7. Control mechanism for public lighting services (continued)

7.3 EnergyAustralia's proposed control mechanism

On the 29 February 2008, the AER published its likely approach to the control mechanism for NSW public lighting services[45]. The AER stated that it will likely apply the following forms of control over the next regulatory period:

- a schedule of fixed prices in the first year of the regulatory control period; and
- a price path (such as CPI-X) established for the remaining years of the regulatory control period.

EnergyAustralia proposes a control mechanism for the 2009-14 regulatory control period that adheres to this approach.

EnergyAustralia also proposes that the distribution determination provides for the application of Clause 6.6.1 of the Transitional Rules. This would apply to pass through events which impact on the cost of providing public lighting services. This approach is consistent with Clause 6.2.6 of the Transitional Rules and is discussed further in Section 7.6.1.

7.3.1 Investment incentives under EnergyAustalia's approach versus those under the roll forward approach

The AER's roll forward approach carries an ex-ante investment incentive. Under this framework, with the capital and operating expenditures locked in at the beginning of the regulatory period, there is strong incentive on the DNSP to ensure that it does not incur costs above those allowed in the price path. If the DNSP overspends its operating expenditure, the overspend cannot be recovered through prices and is lost. Similarly, if the DNSP overspends capital, the investment is not recognised during the regulatory period, no rate of return is delivered until the investment is rolled in to the RAB at its depreciated value.

Conversely, any underspend results in higher than forecast returns to the business. This approach is deliberately designed to encourage the DNSP to drive down costs.

This framework is appropriate where the DNSP has exclusive control over its investment choices in delivering distribution services. The DNSP can decide on the timing of investment decisions, can substitute one investment choice for another, and determine the kind of assets to build to optimise its investment spend.

This is not the case for the public lighting business. The investment choices placed on the public lighting business are directly driven by decisions made by public lighting customers acting in accordance with AS1158 (Road Lighting). These customers make investment choices on the public lighting stock, not based on incentives in an ex-ante framework, but based on the prices proposed by the street lighting business and approved by the Regulator. It is the price that primarily drives efficiency in the public lighting business.

EnergyAustralia employs efficient asset management techniques where existing stock is replaced in an optimal fashion. As such, it is appropriate that when determining the value of the street lighting business a methodology is employed that drives efficient investment behaviour. Since the investment decisions made by public lighting customers are based on price, it is imperative that the price reflect the cost of providing the service.

7.4 Demonstrating the application of the proposed control mechanism

In a similar manner to the pricing of direct control distribution services, public lighting pricing is proposed to be based on the following building block components of revenue:

- an allowance for the return on and of public lighting capital investment; and
- operating and maintenance costs.

The annual public lighting prices therefore reflect an annual rental charge based on the costs of replacing and maintaining public lighting equipment across our network. Prices are developed for each component of the service.[46]

45 Consistent with Transitional Rule 6.2.5(e)

46 The assets employed in providing the public lighting service comprise items such as: poles or standards; brackets; and luminaires. These are termed "components" in this document.

Figure 7.1: Building block approach

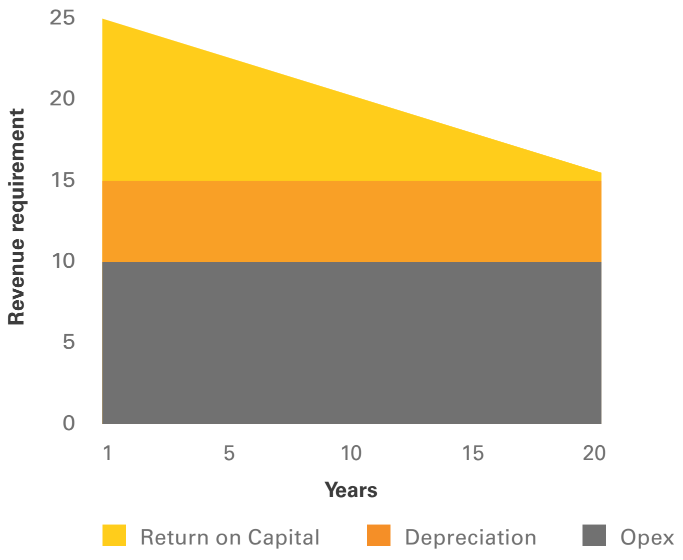


Figure 7.2: Half life assumption

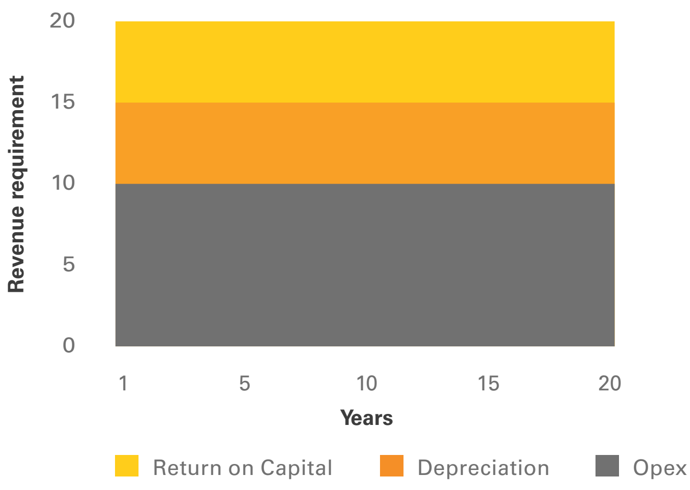
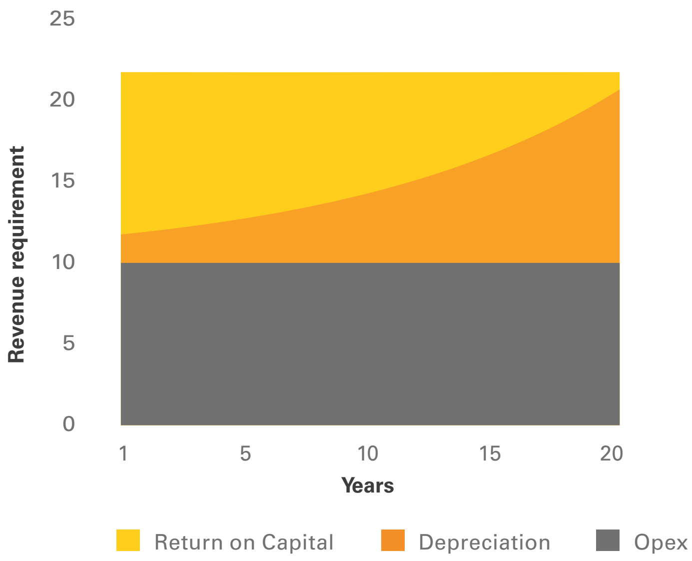


Figure 7.3: Annuity approach



Our proposed methodology for determining a pricing control mechanism represents a continuation of the EnergyAustralia's current methodology for determining public lighting pricing that was accepted by IPART for the 2004-09 period.

The one change to the current arrangement is that EnergyAustralia calculates the return on and of capital using an annuity approach. This is discussed further below.

7.4.1 Comparing methods for calculating prices

Applying a classic building block approach would be problematic for EnergyAustralia's public lighting system, as rates are calculated for each component providing public lighting services. Moreover, as there are a very large number of components in service with a variety of vintages, valuation of the assets would be complex.

Under a classic building block approach, the return on capital component would be levied on the undepreciated amount of the capital invested. As the asset ages, more capital is returned to the business through depreciation. Over time, the amount of return on capital falls, reducing the price applicable to that asset over time. Accordingly, a "young" asset will cost more than an "old" asset,[47] notwithstanding that they provide substantially the same service.

This classic application of the building block approach has two undesirable consequences:

- it presents the customer with a "sawtooth" cost pattern over time, such that its costs increase when an asset is replaced at the end of its useful life, notwithstanding that the new asset is providing substantially the same service as the replaced asset; and
- it requires EnergyAustralia to publish different tariffs for each vintage of each asset. Notwithstanding that EnergyAustralia does not have vintage information for every component in service, the resulting administrative complexity would clearly be undesirable.

47 Consider an example of a streetlight bracket, with a capital cost of $100 and an allowed ROA of 10%.The price for the bracket would be $25 in year 1 and $15.50 in year 20. The present value of the depreciation and ROA payments is $100; correctly valuing the bracket

7. Control mechanism for public lighting services (continued)

In order to avoid this complexity, in the 2004-09 period EnergyAustralia applied a simplified method for public lighting pricing by using a broad average to determine an appropriate return on investment.

The return on capital was estimated by assuming that all of the public lighting assets, which generally have a life of 20 years, remain perpetually halfway through their useful life (ie. with ten years remaining). This simplifying assumption was considered necessary, as many of the 1.24 million individual components represent legacy assets which did not have their installation dates recorded (and therefore their vintage could not be determined). The administrative costs of establishing technical lives of all these assets across the network is clearly uneconomic.

This simplifying assumption addressed the two undesirable elements identified above, but introduced a third: It presented an economic loss to the business on its investment.[48]

This economic loss occurs because applying the half life assumption to the "old" assets (and charging more for them than would be the case under the classic building block approach) is insufficient to offset the present value of the revenue lost by undercharging for "young" assets.

In the 2009-14 regulatory period, EnergyAustralia proposes a pricing mechanism that delivers levellised prices to customers while maintaining NPV neutrality to the business.

Going forward, EnergyAustralia proposes to apply an annuity methodology to establish a price which is effectively an annual rental for each public lighting component. The annuity approach uses widely accepted financial theory; it is the same process used to deliver levellised mortgage payments on a home loan.

Under this methodology, the combined amount of the return on capital and return of capital ("interest and principal") remains constant over the life of the asset ("home loan") although the components will vary relative to each other over time.

The annuity capital charge is calculated based on:

- the replacement value of the asset component;
- the useful life of the asset (20 years); and
- a real rate of return (which in this case is consistent with the rate of return determined by the AER under Transitional Rule 6.5.2).

The annuity methodology therefore establishes a constant annual charge for each component, which simplifies prices to customers, while maintaining NPV neutrality to the business.[49]

Comparing this to the methods discussed previously, it can be seen that the annuity method accounts for both the time value of money and provides a continuous flat price for each component.

Therefore the annuity approach is a superior pricing method for public lighting as it:

- can be administered easily to accurately determine prices for each component; and
- is NPV neutral to the service provider.

EnergyAustralia is confident that the annuity methodology is the most appropriate and economically efficient approach for determining public lighting prices.

48 Consider an example of a streetlight bracket, with a capital cost of $100 and an allowed ROA of 10%. We assume that the age of the bracket (and all other public lighting components) is 10 years. Therefore the annual price for the bracket will be $20; $5 for depreciation, $5 for the return on assets, and $10 for operating costs. The present value of these ROA and depreciation elements is $85, revealing an economic loss for an asset which should be valued at $100.

49 Using the previous example for the $100 bracket, the price charged for this item would be $21.75 in each year (including $10 of operating costs). The present value for the ROA and depreciation elements is $100, correctly valuing the asset.

7.4.2 Proposed control mechanism

Public lighting services have a number of characteristics which distinguish them from other services we provide. The principal difference is that it is predominantly the customer, rather than the service provider, who decides when capital is expended. Customers are charged prices that reflect the cost of public lighting services based on the provision, maintenance and replacement of particular components. This can be contrasted to most of EnergyAustralia's distribution services, where all but the largest customers are charged for the use of the network on an averaged basis.

As a result, capital costs for public lighting vary with the number of particular components that can be directly attributed to the customer. For example, if a council requires an increased number of luminaires, EnergyAustralia would provide them (and increase the price for that council according to the number of additional components). This is considered to be the most efficient form of public lighting pricing, structured on the costs of specific components, rather than a building block approach which is based on changeable forecasts of capital expenditure.

EnergyAustralia proposes to provide a schedule of prices in real dollars as at 1 July 2009. These cost reflective prices will then be adjusted annually to reflect (lagged) changes in real cost escalation for the remainder of the regulatory period.

Consistent with the research underpinning the costs included in the Building Block Proposal for Direct Control Services, EnergyAustralia expects that the actual cost of providing public lighting services will increase faster than the general rate of inflation, owing largely to greater forecast increases in labour and material costs.

As the regulatory framework applicable to public lighting does not lend itself to tracking increases in underlying costs, we must use the price control mechanism as a proxy to allow prices to track to expected increases in costs. As the vast majority of public lighting operating expenditure is labour driven, EnergyAustralia proposes to escalate public lighting prices by the real increase in EGW (energy gas and water) wages.

Calculated from the data in Table 10.2 of the Building Block Proposal, this real increase is an average 3.16 percent[50]. EnergyAustralia therefore proposes a CPI + 1.9 percent price path on average for public lighting prices.

Overheads and material cost escalations are assumed to be zero in real terms ie they will only be escalated for inflation.

7.4.3 Tariff structure

EnergyAustralia currently provides public lighting services under a number of different approaches, represented by different tariffs for individual components, as follows:

Rate 1 applies to components in which EnergyAustralia has invested the capital to provide the component. Rate 1 includes the annualised capital charge as discussed in this proposal, and applicable operating costs.

Rate 2 applies to components in which the customer has invested the capital to construct the public lighting installation. Rate 2 therefore reflects no capital charge, but does include operating costs.

When the component is replaced, either on failure or at the end of its useful life, the new component becomes a Rate 1 component by default. Customers may elect to finance the replacement of the component to maintain Rate 2 pricing.

Rate 3 applies to components for which the customer has funded the capital investment, and also undertakes the maintenance of the public lighting installation. EnergyAustralia is still required to maintain an inventory of these installations in order to settle the electricity market. Rate 3 is set at zero.

50 Labour costs consist of approximately 60 percent of public lighting revenue

When the component is replaced, either on failure or at the end of its useful life, the new component becomes a Rate 1 component by default. Customers may elect to finance the replacement of the component and commit to its ongoing maintenance to retain Rate 3 pricing.

Rate 4, a new rate, applies in circumstances where a customer has chosen to have EnergyAustralia retrofit a component before the end of its useful life (for example, with a higher efficiency luminaire). In this circumstance, in addition to the published Rate 4 tariff, the customer will be required to reimburse EnergyAustralia for the stranded cost of the component being replaced, calculated at half the replacement value. Rate 4 applies to retrofits of components for which a customer has previously been charged under Rate 1.

EnergyAustralia has also included new tariffs for dedicated public lighting infrastructure required when the public lighting system is not able to utilise the existing distribution network assets. This generally applies on traffic routes, where Type V applications generally require illumination from both sides of a traffic route. These dedicated assets serve the public lighting system on the side of the roadway opposite the distribution system. It should be noted that these dedicated assets were optimised out of EnergyAustralia's asset base by IPART. The tariffs for these assets would therefore apply only to new and replacement installations post 1 July 2009.

EnergyAustralia will seek AER approval for any new tariffs that are required in the 2009-14 period. This is most likely to occur with the introduction of new public lighting components.

7.4.4 Establishing the total customer bill

Under the proposed approach, the price of each component of public lighting infrastructure reflects the cost of its provision. The annual bill per customer is calculated by multiplying the component price by the inventory of each component.

The total customer bill is established using the following steps.

Step 1: An annual capital charge is calculated for each component, using the annuity methodology. The current installed capital cost of each different component is used to calculate a rental figure that includes both a return on and of capital for each component (ie 20 equal yearly rental payments are calculated using an interest rate equivalent to the real WACC).

Step 2: The annual direct operating and overhead costs associated with maintaining the component are calculated. These are determined by using assumptions like the spot lamp replacement rate, hourly labour rates and expected corporate costs.

Step 3: The annual SLUoS charge for each component is determined by adding the cost items in Steps 1 and 2.

Step 4: The SLUoS price of each public lighting component is multiplied by each customer's inventory to obtain the total bill for each year of the regulatory period.

This is then compared against the current aggregate public lighting bill for that customer to determine the total amount of any price increase or decrease applicable to that customer.

As discussed below, the transition to cost reflective prices is accomplished through a rebate mechanism applicable to each customer's total bill for public lighting services, to ensure the composite bill does not present a price shock.

7.4.5 A rebate mechanism for customer invoices

EnergyAustralia is concerned to mitigate any price shocks that may arise in the transition to cost reflective prices. To mitigate this impact, a constraint on annual bill increases is proposed for those customers adversely affected by the move to cost reflectivity of public lighting prices. This is equivalent to a cap on the revenue to be derived from a particular combination of services in Transitional Rule 6.2.5(c2)(3). It is proposed that public lighting customers will be transitioned to cost reflective prices as follows:

1. Calculating total 2009 public lighting costs for each of customer using the current component inventory and the cost reflective prices.
2. Determining the impact to each customer by achieving cost reflectivity in Year 1 of the new regulatory period. This is done by comparing the Year 1 bill using cost reflective prices with the expected bill for 2008-09.
3. Applying a limit on the total customer bill, such that the net increase in the bill is capped to no greater than 11 percent (plus CPI) per, year based on the current inventory of components. This cap would apply to each 1 July price change during the regulatory period until the customer reached cost reflectivity. After this point, the customer would then only see approved increases on the fixed inventory.

For example, if the change to cost reflective prices would lead to a 25 percent (real) increase in a customer's public lighting costs in 2009-10, a "rebate" would be calculated to ensure that the increase in year 1 would be capped to 11 percent (real). The customer's bill shows the total amount that would be chargeable with cost reflective pricing, less the amount of the rebate.

In 2010-11 a rebate would again be determined based on limiting the bill impact on the fixed inventory by another 11 percent (real).

By 2011-12, the customer would be close to cost reflectivity, and only require a real increase of 5.3 percent. In the final two years the customer's escalation in real terms will be 1.9 percent which reflects labour rate escalation.

Table 7.1 Example of constraint mechanism

Year	Cost reflective bill (ex CPI)	Rebate	Net bill (ex CPI)	% increase (ex CPI)
FY09	$100	–	N/A	–
FY10	$125	$14	$111	11%
FY11	$127	$4	$123	11%
FY12	$130	$0	$130	5.3%
FY13	$132	$0	$132	1.9%
FY14	$135	$0	$135	1.9%

7. Control mechanism for public lighting services (continued)

EnergyAustralia has estimated that the financial impact of limiting annual bill increases to 11 percent will be in the order of $8.8 million over the 2009-14 regulatory control period. This would be absorbed by EnergyAustralia.

This approach quarantines any historical cross subsidies to the "legacy" inventory in place as at February 2008 (the date the inventory was canvassed for purposes of this submission). Any future installations would be charged at the published cost reflective prices. This approach will send the correct forward looking price signals to customers on which to make sound public lighting investment decisions. Efficient prices are achieved, driving efficient forward behaviour of users of public lighting, while customers are faced with stable costs related to prior investment decisions.

7.5 Departure from AER statement on likely approach

While the control mechanism is generally consistent with the AER's Statement on its likely approach to determining the control mechanism, the methodology for establishing costs on which the control mechanism is based differs in the following respects.

Application of jurisdictional regulatory asset base

The AER's likely approach uses the jurisdictional RAB as its starting point, and calculates an aggregate return on capital. It then makes assumptions regarding the remaining useful life of the portfolio of assets, and calculates an amount for return of capital. It then adds operating expenditures to determine a total revenue requirement.

This is then allocated across the assets in service to determine prices, which would not necessarily be expected to reflect the cost of providing the service.

As discussed below, EnergyAustralia's proposed approach calculates the cost of providing the service, and determines the total revenue under cost reflective pricing and with the rebate mechanism. This aggregate revenue is then checked for reasonableness against that determined under the AER's likely approach.

Under the AER's suggested approach, the asset valuation for public lighting is derived by rolling forward the notional IPART capital base, which is to be estimated by deducting the opening regulatory asset base (RAB) in the current (2004-09) regulatory control period (which only includes prescribed services) from the closing RAB in the previous (1999- 2004) regulatory control period (which includes both prescribed and public lighting services).

The AER therefore proposes in its likely approach that the public lighting asset value be derived from the previous IPART determination, with adjustments for capital expenditure and depreciation in the current regulatory period.

Calculation of prices based on a constant inventory

EnergyAustralia's proposed prices are calculated based on the current levels of inventory in service. This means that forecast levels of annual capital and operating expenditure are not relevant to the price cap moving forward. However, under a price cap form of control, the total revenue will track the level of demand for the services.

EnergyAustralia's methodology for establishing prices and revenue, while different to the approach suggested by the AER, is consistent with the Rule requirements 6.2.5 (c) and revenue and pricing principles. It produces a schedule of prices and caps on prices of individual services.

Our proposal is preferable to the roll forward approach that inherently carries an ex-ante investment incentive that is inappropriate for the public lighting business.

7.6 Justifying the proposed control mechanism

EnergyAustralia believes that, having regard to the factors in 6.2.5(d), the control mechanism proposed is appropriate for the following reasons:

- the methodology for calculating prices is generally consistent with the approach employed by EnergyAustralia in developing the prices approved by IPART in the last regulatory period;
- the approach reduces the administrative costs of the control mechanism by simplifying the information requirements of the revenue building block and pricing mechanism; and
- the proposed approach results in prices that accurately reflects the economic costs of providing public lighting services.

EnergyAustralia's proposed methodology for determining unit prices for public lighting avoids a number of the administrative costs associated with the AER's suggested likely approach. EnergyAustralia's methodology eliminates the need to:

- estimate the remaining life of individual public lighting assets, which EnergyAustralia was not required to do for the 2004 decision;
- separately record historical data of augmentation and replacement public lighting capital expenditure, which is not currently captured by EnergyAustralia's systems;
- create systems that will forecast the required level of replacement capital expenditure over the 2009 to 2014 period; and
- develop models for forecasting demand in public lighting services in the 2009-14 period.

7.6.1 Continuity of approach

Effective 1 July 2004, IPART established a regulatory framework which classified the public lighting service as an "Excluded Service". IPART also issued a rule on the pricing of excluded services, including public lighting. In summary:

- prices must reflect the economic cost of providing the service;
- cost data, etc should be periodically reviewed;
- any time that a price increase is requested, the service provider must provide a report setting out the costs of providing the service, the basis of calculating these costs, the pricing impacts on customers, and any actions taken to manage the pricing impacts to customers; and
- if the Tribunal is not satisfied that the service provider has met these requirements, it may refuse to accept the proposed price increases. The Tribunal does not have scope in the Rule to modify the service provider's pricing proposal.

EnergyAustralia filed a submission in June 2005 requesting a price increase for public lighting services over a four year transition path. In this submission EnergyAustralia outlined an approach which is consistent with the proposed control mechanism outlined above. The Tribunal accepted the prices proposed by EnergyAustralia, and also approved the longer term price path.

The proposed control mechanism represents a continuation of the current approach used by EnergyAustralia to price public lighting services. The benefit of continuing with the current approach is that it avoids the administrative costs to EnergyAustralia of implementing a new regulatory control mechanism for public lighting.

7.6.2 The tribunal's adjustment to EnergyAustralia's prescribed services asset base

An important driver of EnergyAustralia's approach is the absence of a link between public lighting prices in the 2004-09 period and the amount removed from EnergyAustralia's 2004 prescribed service asset base by the Tribunal and ascribed to public lighting.

The Tribunal made reference to a figure of $97.8m ($2003/04) being removed from the prescribed services asset base in its statement approving EnergyAustralia's public lighting prices.

However, the Tribunal's pricing approval was not supported by necessary financial data to underpin its reasons.

As a result, it is unclear what parameters were underlying IPART's pricing decision. Specifically, IPART's approval did not include any decision on:

- the asset valuation over time;
- depreciation rates; or
- level of operating expenditure to be recovered through the approved public lighting prices.

Without this information, there is no clear link between the RAB value referenced by the Tribunal and 2004-09 prices for public lighting services. In this context, there is no economic rationale to calculate the public lighting RAB at 1 July 2009 by rolling forward IPART's adjustment in the prescribed services asset value for new public lighting capital expenditure and depreciation.

A value derived by such an approach is inappropriate, as it:

- does not provide any clear signals of the economic costs of the providing the service (ie. it does not reflect the current costs of providing the service). This is critical, as it is the customer, not EnergyAustralia who determines when capital expenditure is made;
- fails to allow a business to recover the costs of investments that have an effective life spanning more than one regulatory period (ie. without a direct relationship between the RAB and prices, the proposed roll forward cannot ensure the financial capital maintenance of the regulated business); and
- does not give effect to any existing capital expenditure incentive arrangements (ie. a justified reason for not allowing a business to recover its efficient costs).

However, if the AER were to require a roll forward from the 1 July 2004 reference value of EnergyAustralia's public lighting the opening RAB value would be $139.2 million. The table below sets out the details of the roll forward.

Table 7.2 RAB roll forward: public lighting assets

$ million	FY04	FY05	FY06	FY07	FY08	FY09
Opening		97.8	104.4	112.9	123.1	128.3
Depreciation		6.0	6.7	7.5	8.4	9.1
New capex		9.7	12.1	13.8	11.2	16.9
Indexation		2.9	3.1	3.9	2.4	3.0
Closing	97.8	104.4	112.9	123.1	128.3	139.2

The replacement cost of the EnergyAustralia asset base as at March 2008 is $257.7million. Assuming that these assets are half way through their useful lives, then this ODRC asset base is $128.8 million.[57] We note that the "RAB" is $10.4 million greater than the regulatory asset value derived by EnergyAustralia's proposed methodology. Therefore EnergyAustralia is confident that the prices derived through the EnergyAustralia methodology will not be greater than prices derived under an IPART RAB roll-forward methodology.

7.6.3 Comparing the proposed approach with a roll forward methodology

The balances within EnergyAustralia's proposed methodology ensure that the prices and forecast revenues for public lighting accurately reflect the economic cost of providing the service and that these economic costs can be properly reflected in the control mechanism.

In addition to signalling costs to customers to assist in investment decision-making, cost reflective pricing is a prerequisite to any opportunity to introduce competition into provision of this service. To the extent prices do not reflect costs, new entrant service providers will not be attracted to the market, and those that are will not be able to operate sustainably.

However, the proposed approach is likely to recover less revenue from customers than the RAB roll forward method. Table 7.3 shows how much revenue EnergyAustralia estimates it would be entitled to for public lighting services using a RAB roll forward approach. A 2009-10 projection shows the estimated revenue under this method to be $35 million. However under the ODRC model, EnergyAustralia expects to recover only $30.6 million for the same year (cost reflective prices total $35.6 million less a rebate of $4.9 million).

Table 7.3: Allowable revenue using a RAB roll-forward approach

SLUOS Revenue	FY10 projection
Depreciation	10.0
Return on assets @ 7.69%	10.4
Opex	14.6
Total allowable revenue	35.0

57 Assuming straight line depreciation.

Net public lighting revenues of $30.6 million in 2009-10 is only approximately two percent of EnergyAustralia's total regulated revenues. In our opinion, the lower administrative cost of our proposed mechanism outweighs the benefits associated with a more accurate model of costs and is therefore in the long term interests of our customers.

7.7 The NSW public lighting code

EnergyAustralia's Public Lighting Management Plan (Attachment 7.1) has been prepared in accordance with the NSW Public Lighting Code. This plan documents the objectives and strategies developed for the management of EnergyAustralia's public lighting assets.

EnergyAustralia has forecast capital and operating expenditures that will enable the public lighting business to deliver many of the levels of service that are defined in the NSW Public Lighting Code. EnergyAustralia notes that in the 2004 IPART determination there was no provision for costs associated with compliance against the NSW Public Lighting Code.

Section A – During the next regulatory control period EnergyAustralia will meet the following requirements of the NSW Public Lighting Code:

1. Maintenance of our street lighting assets through bulk lamp replacement every 30 months throughout the entire franchise area;
2. Offering energy efficient choices to public lighting customers;
3. Deployment of 10,000 energy efficient lights per annum to replace less reliable (as considered by EnergyAustralia) residential road lights;
4. Improved maintenance practice and increased resources to shorten repair times per local government area to meet minimum service standards;
5. Provision of expanded options for asset relocation services;
6. Improvements in reporting capabilities for customers as per the code requirements; and
7. Night patrols on main traffic route lights to maintain efficiency levels and improve performance (not required by the Code).

7. Control mechanism for public lighting services (continued)

Section B – EnergyAustralia's capital and operating cost forecasts will not enable it to meet the following aspects of the NSW Public Lighting Code:

1. The development and deployment of EnergyAustralia's new inventory and billing system to a reasonable standard;
2. Additional resources to meet timeframes as set for minor capital works;
3. Expenditures related to repair of public lights in priority cases 'quickly' as a minimum service standard;
4. New systems, resources and processes to record, communicate to customers and achieve timeframes for network supply faults (minimum service standard);
5. Costs associated with performance monitoring and reporting of network supply faults (minimum service standard);
6. Introduction of systems, resources and processes to record and achieve 'revised timeframes' in circumstances such as severe weather conditions, large scale power outages, accessibility to a few remote locations and high risk situations where public safety and restorations of power receives priority (minimum service standard and guaranteed service level);
7. Resources to evaluate new technologies, technical analysis, field study, reviews of public lighting customer considerations and audits of public lighting assets; and
8. There is no provision for large scale replacement of existing lights with energy efficient lights other than the planned replacement mentioned in Section A (3).

EnergyAustralia will continue to meet all other requirements of the Code not specified in Section A and will endeavour to meet the requirements in Section B despite the cost constraints. This proposal does not include provisions for any specific future mandatory obligations or other changes in the NSW Public Lighting Code or if the Code in its entirety is made mandatory.

7.7.1 Proposed pass through arrangements for public lighting

There is scope for the costs of providing public lighting services to materially increase as a result of events outside the control of EnergyAustralia in the same way as there is scope for this to occur in relation to the provision of Standard Control Services. This is recognised in relation to Standard Control Services through Transitional Rule 6.6. EnergyAustralia proposes that the pass through provisions in Transitional Rule 6.6 that apply to Standard Control Services should also be applied to the provision of the construction and maintenance of public lighting.

The NSW Public Lighting Code is currently subject to voluntary compliance, and as discussed above, EnergyAustralia has plans in place to comply with most aspects of that Code.

However, should the NSW Public Lighting Code become mandatory, there is the potential for significant cost implications, both for the public lighting system and for the network.

As an example, EnergyAustralia is concerned that mandatory public lighting repair times may require significant investment in the low voltage network. While repairing a faulty light is generally a straightforward task, locating and repairing a network fault can be a considerably more difficult task, particularly where the system is underground in a densely trafficked area. If this is the result of the Public Lighting Code being made mandatory by the NSW Government, EnergyAustralia will seek a cost pass through.

In addition, EnergyAustralia considers the period dating up until 1 July 2009 as a potential risk as any additional costs imposed on the service provider may not be able to be recovered. This is known as a "Dead Zone" event.

In light of the above, EnergyAustralia proposes that the distribution determination include a provision which applies clause 6.6.1 of the Transitional Rules to any pass though event which occurs with respect to the provision of public lighting services. A pass through event should include the following additional pass through events which have been proposed in Chapter 15 of the Building Block Proposal and set out in Attachment 15.1 to that proposal:

- Pass through events occurring prior to 30 June 2009 (Dead Zone Event);
- Force Majeure Event;
- Compliance Event; and
- Cost or Demand Input Variance Event.

The following adaptations should apply to the application of Clause 6.6.1:

- Any reference to Standard Control Services should be read as a reference to *alternative control services being the construction and maintenance of public lighting*.
- The reference to annual revenue requirement in Clause 6.6.1((j) should be read as a reference to the *Schedule of Fixed Prices.*

7.8 Further information

Additional information in respect of EnergyAustralia public lighting services, assets, expenditure and pricing can be found in Attachment 7.2: EnergyAustralia Public Lighting Supporting Information.

Regulatory Proposal part III

Pricing and Negotiating Frameworks June 2008

Contents

1. Procedure for assigning customers to tariff classes

In this chapter, EnergyAustralia demonstrates:

- the proposed approach for assigning customers to tariff classes and reassigning customers from one tariff class to another (including any applicable restrictions);
- compliance with the principles outlined in clause 6.18.4 of the Transitional Rules; and
- linkage to other areas of the Rules, the WAPC, the annual pricing proposal and the recovery of TUoS (where appropriate).

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.12.1(17))

A distribution determination is predicated on a decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions)[1].

1.1 EnergyAustralia's approach to assigning customers to tariff classes

EnergyAustralia's established methodology relating to:

- assigning customers to tariff classes, or
- re-assigning customers from one tariff class to another,

complies with the principles governing assignment or reassignment of customers to tariff classes outlined in Transitional Rule 6.18.4. These principles are discussed in turn.

(1) Customers should be assigned to tariff classes on the basis of one or more of the following factors:

- the nature and extent of the customer's usage; or
- the nature of their connection to the network; or
- whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

Under EnergyAustralia's approach, tariff allocation is determined in order of priority:

(i) customer type, supply voltage, meter type and if available, the annual metered energy consumption at the connection pointpoint, number of phases, and for unmetered supply whether for public lighting or other unmetered supplies. Tables 1 and 2 provide further information on this allocation methodology;

(ii) whether the connection is an existing or new connection; or

(iii) the type of meter installed at the connection point.

It is EnergyAustralia's policy that all new connections and all upgraded connections (eg single phase to multiple phases) must install a Type 5 or better (Types 1 to 4) meter.

A customer is defined specifically as a connection with an individually allocated National Metering Identifier (NMI), consistent with NEMMCO's NMI Allocation Rules.

This procedure relates specifically to the application of mandated tariffs. Where EnergyAustralia may offer voluntary tariffs from time to time, the assignment of those tariffs is considered to be at the request of the customer rather than EnergyAustralia. Voluntary tariffs will be available upon application by the customer or their retailer subject to the terms and conditions for that tariff offered by EnergyAustralia. Where the voluntary tariff offer lapses, this procedure will determine the relevant mandated tariff to which the customer reverts[1].

EnergyAustralia's allocation of tariffs is aligned with NEMMCO's metrology procedure, which prescribes the meter type based on voltage and annual consumption.

All existing connections are allocated to a tariff on the basis of voltage, meter type and annual metered energy consumption (with the one exception of site specific cost reflective network price customers, outlined at Section 1.2). This allocation process is outlined in Table 1 and Table 2. Modified connections with no relevant load history have the principal network prices applied on the same basis as a new connection.

1 Transitional Rule 6.12.1(17)

Table 1: Tariff application for business customers

Supply Voltage	Metering Installation Type	Energy Level	Default Principal Network Price	Meter Reading Cycle
33 to 132 kV	1, 2, 3	All Energy Level	ST Demand ToU	Monthly
5 to 22 kV	1, 2, 3		HV Demand ToU (System)	Monthly
240 or 415 Volts	3	Over 750 MWh p.a.	LV Demand ToU (System)	Monthly
	4	Between 160 MWh pa & 750 MWh p.a. (typically over 100 amp 3-phase)	LV Cap750 (System)	Monthly
	5	Between 40MWh pa & 160MWh pa (typically below 100 amp 3-phase)	LV kW Capacity ToU (System)	Monthly
		Below 40MWh p.a. (after 12 months of load history)	LV Energy40 ToU (System)	Quarterly
	6	Below 40MWh p.a.	LV Business non-ToU	Quarterly
	7	Below 40MWh p.a.	Public Lighting	Monthly Estimate
			General Unmetered	Monthly Estimate

Table 2: Tariff application to residential load

Supply Voltage	Metering Installation Type	Energy Level	Default Principal Network Price	Meter Reading Cycle
240 or 415V	5	All Energy Levels	LV Energy40 ToU (System)	Quarterly
	6	All Energy Levels	Domestic non-ToU	Quarterly

For new connections, where there is no previous load history, the default tariff is based on customer type, supply voltage and meter type. The annual consumption is assumed to be less than 40MWh per annum, unless there is three phase metering, when the annual consumption is assumed to be between 100MWh and 160MWh per annum.

After 12 months load history has been accumulated, the customer or their retailer can apply to transfer to an alternative network price using the Network Price Application Form available in the ES7 "*Application of Network Use of System Charges*" document. No backdating of the new network price is permitted, unless approved by EnergyAustralia.

Applications for a new network tariff are anticipated to generally request cheaper substation network tariffs. Substation tariffs reflect where a customer has contributed to the substation from which they are supplied. Approval to move to a new network price will be based on an assessment of the voltage, likely annual energy consumption, and demonstration of whether the customer has contributed to the construction of the substation to which they are connected. Substation tariffs are available upon application.

If approved, the price change will apply from the start of the next billing period following the date of receipt of the price change application.

1. Procedure for assigning customers to tariff classes (continued)

EnergyAustralia's assignment of tariffs can be summarised in Figure 1.

It can be seen that it is not always necessary to answer every decision to determine the relevant tariff. Note that Figure 1 does not cover Cost Reflective Network Price (CRNP) Customers, described in Section 1.2.

1.2 Cost reflective network price customers

EnergyAustralia calculates site specific tariffs for customer with:

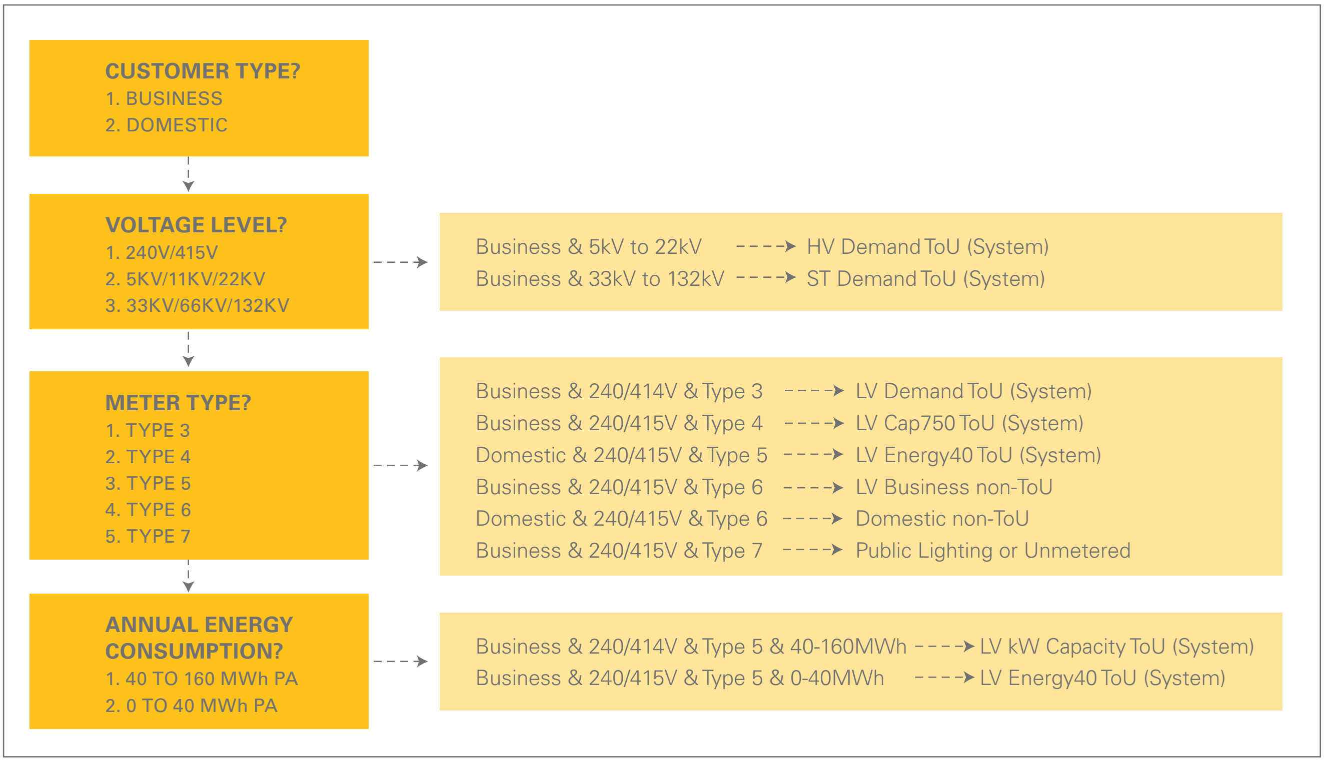
- annual consumption in excess of 40GWh; or
- demand of 10MW on at least three half hour periods within a 12 month period.

These are the only criteria in determining whether Cost Reflective Network Pricing (CRNP) is applicable.

> Customers with a similar connection and usage profile should be treated on an equal basis.

EnergyAustralia's policy is to administer customer tariff allocation on the basis of customer supply voltage, meter type and where available the annual metered energy consumption. The details of this tariff allocation policy are outlined in Tables 1 and 2. Given this standard policy, customers with similar connection and usage profiles are treated on the same basis.

Figure 1: Decision of assigning customers to tariffs



The backdating of new network prices is not ordinarily permitted unless approved by EnergyAustralia Network. Customers may only have their prices changed once per 12 month period.

> However, customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile.

It is EnergyAustralia policy to treat customers with micro-generation facilities no less favourably than customers without these generation facilities but with a similar consumption profile. Allocation of an embedded generation customer to a network tariff will be made on the same basis as other connection applications; this being the supplied voltage, meter type and the annual metered energy consumption (if available) of the customer. The network tariff will include fixed and variable components and if the customer's demand were to be met entirely by the micro-generator then the levied charge will be only the fixed connection component.

> Prohibition of DUoS charges for the export of energy
>
> (a) A Distribution Network Service Provider must not charge a Distribution Network User DUoS charges for the export of electricity generated by the user into the distribution network.
>
> (b) This does not, however, preclude charges for the provision of connection services.

Where a customer with micro-generation facilities is able to supply their own load and also generate energy into the network, no charges are applied to the energy exported. If the customer is purely a generating source (rather than a load with micro-generation), then no network tariff applies. Network tariffs are only relevant where load is present.

> A Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

A review of a customer's network tariff is carried out in May each year to assess if the tariff is still correct given potential changes in annual usage and meter type (a change in voltage would be treated as a new connection). EnergyAustralia's network tariff policy is generally aligned to consumption bands, so for example, network tariff EA025 LV Energy40 ToU applies to 0-40MWh pa customers, and then above this tariff EA302 LV kW Capacity ToU applies to 40-160MWh pa customers.

If, after 12 months, a customer has increased usage from say 35MWh pa to 43MWh pa, the decision to move the customer from EA025 (the correct tariff for 35MWh pa customers) to EA302 (the correct tariff for 43MWh pa customers) is deferred by one year. This is to mitigate against customers oscillating across tariff policy thresholds, and potentially being repeatedly assigned back and forth between tariffs.

EnergyAustralia applies a tolerance of ±20 percent around tariff thresholds. So if the same customer were to consume 49MWh pa, they would be reassigned immediately to the new tariff, being more than 20 percent above the 40MWh threshold. However, since they are using 43MWh pa usage, the customer fulls within the band tolerance of 40MWh ± 8MWh so their tariff re-assignment is deferred. If the same customer is then found to still consume above 40MWh after two years, the threshold bands do not apply, and the customer is reassigned from network tariff EA025 to EA302. The relevant retailer is notified of the impending change, and the customer re-assigned to the new network tariff as at 1 July.

The assessment of the customer's usage is based on the most recent 12 months of history, but if a customer's consumption has fallen because of vacancy of one month or more during the previous 12 months, the customer is excluded from a potential tariff re-assignment.

2. Indicative prices for direct control services

RULE REQUIREMENTS
(TRANSITIONAL RULE 6.8.2(c)(4))

The Rules require EnergyAustralia to provide in its Regulatory Proposal indicative prices for Direct Control Services for each year of the regulatory control period[2].

The indicative prices outlined in this chapter recover revenues for EnergyAustralia's distribution and transmission networks, costs to cover transmission payments to TransGrid for use of their transmission network, and revenues to cover obligations to the NSW Government's Climate Change Fund. A number of assumptions have been made to derive these indicative prices. These prices are therefore indicative only and are not binding. They are provided as a guide as to network price levels over the next regulatory period.

Actual prices are dependent on:

1. The AER's decision relating to this Regulatory Proposal for 2009-14;
2. The AER's decision relating to TransGrid's Regulatory Proposal for 2009-14;
3. Any decision of the NSW Government to reduce or increase in size the Climate Change Fund;
4. Any pass through events that may arise during the remainder of the 2004-09 or the 2009-14 regulatory periods, in particular a roll out of AMI; and
5. Changes in cost allocation between tariff classes brought on by changing patterns of network use between customer groups.

Table 1 Indicative prices (¢/kWh nominal)

	FY09	FY10	FY11	FY12	FY13	FY14
Domestic	6.0	7.7	8.8	10.0	11.4	12.9
LV Business	4.7	5.7	6.3	7.0	7.8	8.7
Public lighting & other unmetered	4.2	5.2	5.8	6.4	7.1	7.9
HV Business	2.9	3.5	3.8	4.2	4.7	5.2
ST Business	1.7	2.0	2.3	2.5	2.8	3.1
CRNP customers	0.9	1.0	1.1	1.2	1.3	1.5

2 Transitional Rule 6.8.2(c)(4)

Prices have been shown as ¢/KWh for energy consumed but it should be noted that actual prices depend on the specific tariff and, are made up of a number of components of fixed, energy and capacity charges.

A general network price increase of 23 percent is required at 1 July 2009, followed by ongoing annual increases of 12 percent for the remaining years of the regulatory period[3]. These indicative price changes do not align with the X factor calculations in Chapter 13 of Part I as they include estimates of TransGrid's charges and other components. These average price increases are required to fund EnergyAustralia's substantial capital and operating programs. These programs are explained in EnergyAustralia's Building Block Proposal.

EnergyAustralia has long advocated cost reflectivity in network pricing, so that economic signals conveyed to customers will influence their consumption patterns. As a consequence, domestic customers can expect to see progressively larger increases compared to other tariff classes, to accompany their stronger peak contribution with increased air conditioning penetration. Domestic customers are making up a greater proportion of the network peak, and network peak drives augmentation capital expenditure. To signal this cost, domestic customers will have to face higher network charges reflecting the growing contribution to peak demand.

Public lighting network use of system prices will continue to remain higher that other low voltage tariffs, because of their poor power factor performance. Poor power factor means they contribute more in relative terms to peak demand. However, as the network progressively becomes more summer peaking, the contribution of public lighting capital expenditure will diminish. Public lighting therefore will see marginal reductions over the regulatory period, relative to other tariffs.

Customers connected to the high voltage network (11kV) or to the subtransmission network (33kV, 66kV and 132kV) will continue to experience lower network charges. This is because these customers use a smaller proportion of the network by virtue of being connected closer to EnergyAustralia's connection points to the transmission network. They also generally demonstrate a better load profile, being flatter in their usage patterns, and therefore contributing less, in relative terms, to network peak costs.

Indicative prices for Miscellaneous and Monopoly Charges are provided in Part II Attachment 13.1 and indicative pricing for Public Lighting SLUoS charges are provided in Part II Attachment 7.2.

3 Price increases in this Proposal assume a CPI + ten percent, and CPI thereafter, increase in TransGrid charges.

3. Treatment of TUoS recovery in distribution pricing

In this chapter EnergyAustralia outlines its proposed approach to treatment of TUoS recovery, consistent with the Transitional Rules.

> **RULE REQUIREMENTS**
> (TRANSITIONAL RULE 6.12.1(19))
>
> A distribution determination is predicated on a decision on how the DNSP is to report to the AER on its recovery of TUoS charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges[4].

3.1 EnergyAustralia's current approach to reporting TUoS recovery

In setting prices to apply to end use customers (through a retailer), a DNSP must recover TUoS charges as well as DUoS charges.

TUoS charges pay for upstream costs imposed by the relevant TNSP. EnergyAustralia generally passes on the same form of price structure where metering and equivalent price components permit. Details of how EnergyAustralia proposes to structure TUoS charges to end use customers will be detailed in EnergyAustralia's pricing proposal to be submitted to the AER following publication of the distribution determination.

EnergyAustralia's current approach allows for unders-overs reporting for TUoS revenue recovery. EnergyAustralia reports its compliance with this mechanism as part of the submission of the volume weights to be used under the WAPC. The same information is provided as part of each annual pricing proposal.

The AER's guideline for Direct Control Services notes that transmission related payments include:

- transmission charges paid to TNSPs for use of transmission system:
- avoided TUoS paid to embedded generators; and
- payments made to other DNSPs for use of their network.

3.2 Proposed approach

With respect to the definition of Transmission Cost Recovery Tariffs, EnergyAustralia proposes that the approach set out by the AER in Appendix B of its Guideline on control mechanisms for Direct Control Services be adopted for the 2009-14 regulatory control period.

The AER guidelines allow for recovery of costs assocated with TUoS charges to be paid for transmission services, together with inter-distributor transfer payments and avoided TUoS payments. Inter-distributor transfer payments relate to payments made to another DNP for network services[5]. Avoided TUoS payments relate to payments made to an embedded generator by a DNSP, reflecting a pass through of TUoS "savings" that a DNSP receives for energy generated locally, rather than having to be delivered through the transmission network[6].

To maintain NPV neutrality to the cash value of the unders-overs balance, it is proposed that an indexation rate be applied.

3.3 Carry over between regulatory control periods

Whilst a zero unders/overs balance will be targetted in setting prices in 2008-09, inevitably there will be volume variance, leaving a residual balance at the end of the 2004-09 regulatory period. It is proposed that any unders-overs from the current regulatory period be carried forward in to the 2009-14 period. For purposes of the AER setting the X factors for this revenue proposal, the carry forward does not need to be considered, other than to recognise that the application of unders-overs in the price setting process can apply to the first year (P_0) adjustment in the same way as any other annual 1 July price change.

Under the WAPC, there is no unders-overs requirement. As TUoS revenues represent a relatively small component of the total network charges (17 percent for EnergyAustralia), there is limited exposure to a DNSP accumulating a large over or under recovery when annual adjustments are made. No specific mechanism is required to deal with unders-overs balances from the 2004-09, other than a simple carry forward into the first year of the 2009-14 period.

4 Transitional Rule 6.12.1(19)

5 EnergyAustralia pays Integral Energy for network services being supplied from their Carlingford and Guildford substations.

6 No real savings are made by a TNSP or DNSP since any TUoS saved becomes an under-recovery for the TNSP and is simply recovered through prices the following year

3.4 Timing of assessment of under/overs balance of TUoS recovery for pricing purposes

Under the current regulatory framework, IPART allows for adjustments to the TUoS component of distribution pricing. These adjustments are aimed at achieving a nil balance to the TUoS unders/overs account at the end of the year for which prices are being set[7]. To achieve this outcome, each DNSP is required to make an assessment of the forecast unders/overs balance up to the end of the current financial year t-1, when prices for year t are being calculated.

The diagram below demonstrates the timing in assessing the TUoS unders/overs to deliver a nil balance by the end of year t:

Figure 2 illustrates the timing of assessing the TUoS recovery. The DNSP must make an assessment of the TUoS unders/overs balance up to 30 June of the current year (t-1) when targeting a nil balance for the following year. Any other approach to timing of the assessment of the unders/overs balance will not deliver a nil balance.

This approach is consistent with the Transitional Rules[8], that states: *The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of the TUoS for the relevant regulatory year adjusted for over or under recovery in the previous regulatory year.*

In setting TUoS prices for year t, charges are set on basis of forecast TUoS revenue and costs to the end of t-1.

EnergyAustralia proposes to adopt this timing arrangement in setting prices for the recovery of TUoS amounts from distribution customers.

The proposed approach is a departure from the AER guidelines that only allow for adjustments using auditied quantities from year t-2 to assess the TUoS unders/overs balance[9]. The guidelines state:

The amount to be passed onto customers in year t= Forecast TUoS(t) + overs and unders adjustment to be applied in year t.

Where:

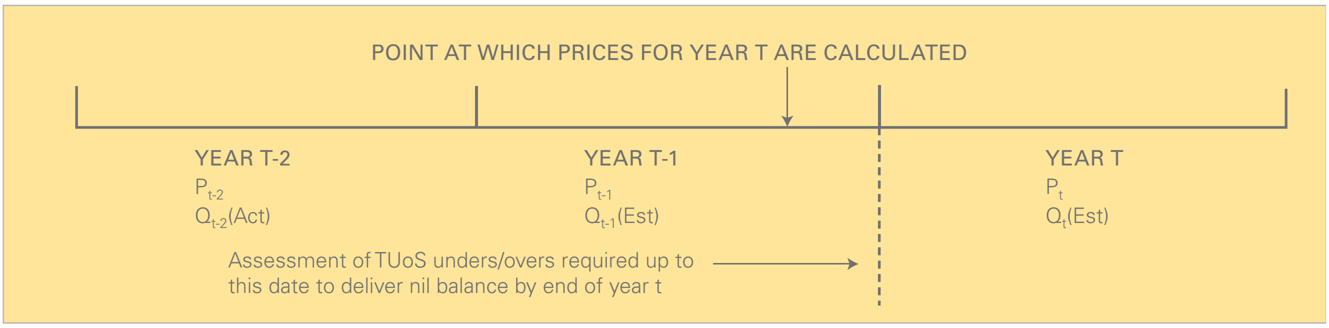
overs and unders adjustment to be applied in year t = amount actually paid by DNSPs for TUoS in year t-2, minus the amount passed onto customers by way of TUoS charges by the DNSP in year t-2

EnergyAustralia therefore proposes that the definition for overs under adjustment to be applied in year t to be:

The TUoS forecast to be paid by EnergyAustralia in year t-1, less TUoS recovered from customers in year t-1, adjusted by the unders/overs balance from year t-2

This approach is consistent with the current regulatory arrangements and allows for closer targetting of a nil unders/overs balance, as anticipated by the Transitional Rules.

Figure 2: Timing of TUoS unders/overs assessment



7 IPART Determination No 2, 2004, clause 6.4(d)

8 Transitional Rule, clause 6.18.7(b)

9 AER Guidelines on control mechanisms for Direct Control Services for the ACT and NSW 2009 distribution determinations, February 2008, Appendix B: Transmission Cost Recovery Tariffs

4. Pricing methodology for transmission support network

In this chapter EnergyAustralia demonstrates how its pricing methodology for transmission is consistent with the Rules.

RULE REQUIREMENTS
(TRANSITIONAL RULES 6.12.1(20), 6.12.3(i))

A distribution determination is predicated on a decision on the proposed pricing methodology for Prescribed (Transmission) Standard Control Services, in which the AER either approves or refuses to approve that methodology and sets out reasons for its decision[10].

The Rules provide that the AER must approve EnergyAustralia's proposed pricing methodology for EnergyAustralia Prescribed (Transmission) Standard Control Services if the AER is satisfied that the methodology[11]:

(1) gives effect to and is consistent with the Pricing Principles for Prescribed Transmission Services; and

(2) complies with the requirements of the pricing methodology guidelines.

If the pricing methodology for transmission is a methodology under 6.12.13, the substitute methodology must be determined on the basis of the current Regulatory Proposal and amended on that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

This chapter summarises EnergyAustralia's approach to transmission pricing for the 2009-14 regulatory period. The full transmission pricing methodology, which the AER must either approve or refuse to approve can found in Attachment 4.1: EnergyAustralia's *Transmission pricing methodology*.

The remaining sections of this document are structured as follows:

- Section 4.1 gives an overview of EnergyAustralia's obligations in respect to Part J (Chapter 6A) of the Rules; and
- Section 4.2 outlines the key elements of EnergyAustralia's pricing methodology, describing what elements are the responsibility of EnergyAustralia, and what elements are the responsibility of TransGrid as the co-ordinating TNSP.

4.1 Transmission rule requirements

Clause 6.1.6 of the Transitional Rules applies the pricing rules in Part J of Chapter 6 to EnergyAustralia's Prescribed (Transmission) Standard Control Services. This clause further provides that Part J applies as if references to "prescribed transmission services" were references to EnergyAustralia Prescribed (Transmission) Standard Control Services and the reference in clause 6A.22.1 to clause 6A.3.2 were a reference to rules 6.6 and 6.13.

Clause 6.8.2(c)(9) of the Transitional Rules requires EnergyAustralia to submit a proposed pricing methodology to the AER as part of its Regulatory Proposal submitted to the AER. This chapter outlines some of the key elements of EnergyAustralia's proposed transmission pricing methodology.

Clause 6A.24.1 of the Rules states that the pricing methodology:

(1) Allocates the aggregate annual revenue requirement (AARR) for Prescribed Transmission Services to:

  (i) the categories of Prescribed Transmission Services; and

  (ii) transmission network connection points; and

(2) Determines the structure of the prices that a Transmission Network Service Provider may charge for each of the categories of Prescribed Transmission Services.

In addition the methodology must be consistent with and give effect to the Pricing Principles for Prescribed Transmission Services and comply with the requirements of, and contain or be accompanied by the information required by the pricing methodology guidelines prepared by the AER under Rule 6A.25.

10 Transitional Rule 6.12.1(20)

11 Transitional Rule 6.12.3(i)

4.1.1 EnergyAustralia's role in transmission pricing

This proposal is made in the context that EnergyAustralia relies on TransGrid as the co-ordinating TNSP in NSW for the calculation of transmission prices.

Section 6A.29 of the Rules covers situations (such as in NSW) where there are multiple TNSPs within the one region. In these circumstances the Rules require a Co-ordinating Network Service Provider to be appointed (in this case TransGrid) who is responsible for the allocation of all relevant AARR within that region, in accordance with Part J.

The Rules require EnergyAustralia to determine the AARR for its own transmission system assets which are used to provide EnergyAustralia Prescribed (Transmission) Standard Control Services.

TransGrid, as Co-ordinating Network Service Provider must allocate the total AARR of all TNSPs within the NSW region.

EnergyAustralia's responsibility is limited to classifying transmission assets to the relevant categories of Prescribed Transmission Services, and also the allocation of the AARR to each of the categories of Prescribed Transmission Services. EnergyAustralia is also responsible for pricing prescribed connection services.

TransGrid will be required to submit its own pricing methodology for transmission services as part of its regulatory proposal.

4.2 Key elements of EnergyAustralia's transmission pricing methodology

As EnergyAustralia is an appointing provider of transmission services in NSW, the attached transmission pricing methodology is limited to:

1. Calculation of the AARR for each year of the regulatory control period;
2. Proposing a methodology to determine whether assets fall in to the categories of exit, entry, shared or common service;
3. Allocating the AARR to those asset classes of exit, entry, shared and common service, using an attributable cost share method, to determine an Annual Service Revenue Requirement (ASRR) for each asset class;
4. Allocating the ASRR of each asset class to the specific assets within that asset class;
5. Detailing the methodology for implementation of the priority ordering approach under clause 6A.23.2(d) of the Rules including worked examples;
6. Billing arrangements for a small number of direct connected transmission customers;
7. Management of prudential requirements and prudent discounts for new or existing connections to the EnergyAustralia transmission network;
8. Describing how asset costs allocated to prescribed entry services and prescribed exit services at a connection point, which may be attributable to multiple transmission network users, will be allocated; and
9. Detailing how EnergyAustralia intends to monitor and develop records of its compliance with its approved transmission pricing methodology, the pricing principles for Prescribed Transmission Services (clause 6A.23) and Part J of the Rules in general.

Elements of a pricing methodology required as part of the AER Guidelines and NER and carried out by TransGrid on behalf of EnergyAustralia are:

1. any adjustments required to be made to the locational component of the ASRR as required in the Rules[12];
2. any adjustments required to be made to the pre-adjusted non-locational component of the ASRR as required in the Rules[13];
3. allocation of the locational component of prescribed TUoS services to transmission connection points; and
4. establishing structure and price for common service, general, and locational charges at each of EnergyAustralia's transmission connection points[14].

These requirements will be dealt with in TransGrid's transmission pricing methodology, which will be available at www.transgrid.com.au after approval from the AER.

12 Rules, clause 6A.23.3(c)(1)

13 Rules, clause 6A.23.3(c)(2)

14 That is, EnergyAustralia transmission connection points that supply EnergyAustralia's distribution network, not to be confused with TransGrid connection points that supply EnergyAustralia's distribution network.

5. Negotiating frameworks, negotiated distribution service criteria and negotiable component criteria

In this section, EnergyAustralia proposes the negotiating frameworks and criteria for Negotiated Distribution Services and the Negotiable Components of Direct Control Services to apply in the 2009-14 regulatory control period.

RULE REQUIREMENTS

(TRANSITIONAL RULES 6.12.1(16), 6.12.1(16B) AND 6.12.1(15))

A distribution determination is predicated on, if relevant, a decision in which the AER decides the negotiable component criteria for the Distribution Network Service Provider;

A distribution determination is predicated on a decision on any negotiating framework that is to apply to the DNSP for the regulatory control period (which may be the negotiating framework as proposed by the provider, some variant of it, or a framework substituted by the AER).

5.1 Negotiating framework

EnergyAustralia must prepare a document (i.e., the *negotiating framework*) that sets out the procedures to be followed by EnergyAustralia and applicants who wish to be provided with either a negotiable service or a negotiable component of a Direct Control Service. The services which will be subject to these frameworks are explained in Part II of the Regulatory Proposal in Chapters 1 and 3.

The minimum requirements for the framework are set out in the NER Part D 6.7.5(c) and NER Part DA 6.7A5(c) (respectively). These requirements are comprehensive and include:

- requirements around provision of information, including specific cost information;
- specified timeframes for negotiation (to be specified by EnergyAustralia in proposing its negotiating framework);
- disputes must be resolved on the basis of the dispute resolution process set out in the Law and the NER[15]; and
- the framework must not be inconsistent with the requirements of NER5.3, 5.4A and 5.5.

Negotiation frameworks apply to both:

- negotiable components of Direct Control Services; and
- negotiated distribution services.

The provisions in these clauses 6.7.5(c) and 6.7A.5(c) are identical. The NER (Part DA6.7.5(f)) states that EnergyAustralia may prepare and submit a document that contains both negotiating frameworks and that both frameworks may be combined into a single framework.

EnergyAustralia has determined to propose and submit a single negotiating framework covering both types of service.

EnergyAustralia's Negotiating Framework is provided in Attachment 5.1.

15 Part 10 of the NEL and Part L of the Transitional Rules sets out the dispute resolution process in relation to disputes regarding terms and conditions of access to Direct Control Services and negotiated distribution services.

5.2 Proposed negotiable component criteria

In addition to the negotiating framework, the AER must determine EnergyAustralia's Negotiated Distribution Service Criteria and Negotiable Component Criteria as part of its distribution determination for EnergyAustralia. These criteria are to be applied by EnergyAustralia in negotiating terms and conditions of access and by the AER is resolving any access disputes.

These criteria are comprehensive and include principles in relation to pricing.

The criteria themselves are largely prescribed in the NER. Specifically, the negotiated distribution service criteria and the negotiable component criteria must give effect to and must be consistent with the principles set out in Transitional Rule Part DA 6.7.1 and Transitional Rule Part DA 6.7A.1, respectively.[16]

EnergyAustralia has noted the Negotiated Transmission Services criteria determined in the AER's recent decision on ElectraNet which adopted the relevant principles from Chapter 6A as the criteria without any additional matters. EnergyAustralia assumes that the AER would take a similar approach in relation to its distribution determinations. EnergyAustralia would support the AER adopting the Negotiated Distribution Service Principles in clause 6.7.1 and the negotiable component principles set out in clause 6.7A as the appropriate criteria.

16 NER Part D 6.7.4(b) and NER Part DA 6.7.4(b).

Glossary

Glossary

A

AARR	Aggregate Average Revenue Requirement
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AEMC	Australian Energy Market Commission
AESDR	Annual Electricity System Development Review
AMI	Advanced Metering Infrastructure
ARR	Annual Revenue Requirement
ASP	Accredited Service Provider
ASRR	Annual Service Revenue Requirement
ATO	Australian Tax Office
AVSIM	Statistical reliability analysis tool

B

B2B	Business-to-Business
BSP	Bulk Supply Point

C

CAIDI	Consumer Average Interruption Duration Index
CAPEX	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CEG	Competition Economics Group
CFL	Compact Fluorescent Light
CIGRÉ	Conseil International des Grands Réseaux Électriques – An International organisation dedicated to the identification and the development of solutions to technical issues in the power supply sector
COAG	Council of Australian Governments
CPI	Consumer Price Index
CRA	Charles River & Associates
CRNP	Cost-Reflective Network Pricing
CT	Current Transformer

Glossary (continued)

D	
DWE	Department of Water & Energy (NSW)
DLF	Distribution Loss Factor
DM	Demand Management
DMIS	Demand Management Incentive Scheme
DND	Distribution Network Development Model
DNSP	Distribution Network Service Provider
DORC	Depreciated Optimised Replacement Cost
DRP	Design Reliability and Performance Licence (DRP) Conditions
DUoS	Distribution Use of System
E	
EA	EnergyAustralia
EBSS	Efficiency Benefit Sharing Scheme
EIS	Environmental Impact Statement
EISS	Energy Industry Superannuation Scheme
ElectraNet	SA Transmission Network Service Provider
EPA	Environmental Protection Authority
ESC	Essential Services Commission of Victoria
EWP	Elevated Work Platforms
F	
FMECA	Failure Modes and Effects Criticality Analysis
FRC	Full Retail Contestability
FRMP	Financially Responsible Market Participant
G	
GIS	Geographical Information System
GWh	Gigawatt hour
H	
HSL	Hochstadter Single Lead – a lead sheathed type of cable with paper insulation
HV	High Voltage

I

IAMS	Integrated Asset Management System
IDC	Interest During Construction
IEEE	Institute of Electronics and Electrical Engineers
IPART	Independent Pricing and Regulatory Tribunal of NSW
ITAA	Income Tax Assessment Act

K

KW	Kilowatt (one kW = 1000 watts)
KWh	Kilowatt hour

L

LNSP	Local Network Service Provider
LR	Local Retailer
LRMC	Long Run Marginal Cost
LV	Low Voltage

M

MAIFI	Momentary Average Interruption Frequency Index
MAS	Metering Administrative System
MBS	Metering Business System
MCE	Ministerial Council on Energy
MDA	Metering Data Agent
MDI	Maximum Demand Indicator
MDM	Metering Data Manager
MDP	Metering Data Provider
MDS	Metering Data System
MNSP	Market Network Service Provider
MP	Metering Provider
MRAM	Maintenance Requirement Analysis Manual
MSATS	Market Settlement and Transfer Solution
MW	Megawatt (one MWh = 1000 kWh)
MWh	Megawatt hour

Glossary (continued)

N

NAC	Network Access Charge
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NERA	National Economic Research Associates
NMI	National Metering Identifier
NPV	Net Present Value
NSP	Network Service Provider
NTER	National Tax Equivalent Regime
NUoS	Network Use of System

O

ODV	Optimised Depreciated Value
ODRC	Optimised Depreciated Replacement Cost
Ofgem	Gas and Electricity Market Authority UK
OH&S	Occupational Health and Safety
O&M	Operating & Maintenance
OMS	Outage Management System
OPEX	Operating Expenditure
ORG	Office of the Regulator-General (VIC)

P

PASA	Projected Assessment of System Adequacy
PB Associates	Parsons Brinckerhoff Associates
PDS	Prescribed Distribution Services
PTRM	Post Tax Revenue Model

R

RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RCM	Reliability Centred Maintenance
RFM	Roll-Forward Model
RIN	Regulatory Information Notice
RTA	Roads and Traffic Authority (NSW)

S

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SKM	Sinclair Knight Merz
SLUoS	Street Lighting Use of System
SOC	State Owned Corportation
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
ST	Subtransmission
STPIS	Service Target Performance Incentive Scheme
STS	Subtransmission substation
SWMS	Safe Work Method Statements

T

TCA	Testing and Certification Australia
TMP	Technical Maintenance Plan
TNSP	Transmission Network Service Provider
ToU	Time of Use
TransGrid	NSW Transmission Network Service Provider
TUoS	Transmission Use of System

V

VoLL	Value of Lost Load

W

WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap

Appendices

Appendix 1: Attachments to Building Block Proposal

Attachments

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Attachment 4.5	Planning Criteria
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Attachment 4.7	Annual Electricity System Development Review (AESDR) 2006/07, 2007/08
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Attachment 5.9	Low Voltage Network Capital Requirements, Evans & Peck Report 2008
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Appendix 11: Attachments to Service Classification and Control Mechanism Proposal

Attachments

Appendix III: Attachments to pricing and negotiating framework proposal

Attachments

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