EnergyAustralia

EnergyAustralia's submission to

Australian Competition &
Consumer Commission

Transmission Revenue Determination 2004-2009

Energy

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EXECUTIVE SUMMARY

EnergyAustralia operates a distribution network in NSW. However, some of the network assets owned by EnergyAustralia are defined to be transmission assets under the National Electricity Code (the Code). Therefore, unlike other distribution network service providers (DNSPs), EnergyAustralia is regulated by two regulators – a regulator for its distribution assets (IPART), and a regulator for its transmission assets (ACCC). This submission represents EnergyAustralia's submission to the ACCC relating to the revenue cap that will apply to EnergyAustralia's earnings for its transmission business from 2004-2009. A similar submission was made to IPART on 10 April 2003 that related to the regulation of distribution assets within the EnergyAustralia network for the period 2004-09.

1. Regulation of EnergyAustralia's network

Transmission boundary

Elements of EnergyAustralia's network are classified under the Code as transmission assets because they operate at voltages of 66kV or higher and operate in parallel and provide support to TransGrid's transmission network. The Code also provides for assets operating between 66kV and 220kV that do not operate in parallel and support the transmission network to be deemed by the ACCC as part of the transmission network.

EnergyAustralia applied to the ACCC to exercise its powers to deem all its assets between 66kV and 132kV to be transmission assets as it would have allowed internal business processes to be streamlined, reduce overall costs to consumers and would improve the accuracy of financial reporting for EnergyAustralia. The ACCC rejected EnergyAustralia's proposal on several grounds including the fact that our proposal failed to address the fundamental problem of being regulated by two regulators.

Consequently, the standard definition of transmission assets under the Code continues to apply (i.e. only assets above 66kV that operate in parallel to and support transmission assets will be treated as transmission under the Code). However, this raises a number of difficulties during the next regulatory period as the elements of EnergyAustralia's network that are recognised as transmission assets will change before the start of the determination period, and change throughout the period. This is due to augmentations that are planned for the transmission network that will change the configuration and operation of the network, thereby changing the role of some assets to that of a transmission function.

EnergyAustralia is the only business within the National Electricity Market (NEM) that is regulated by two economic regulators. This causes inefficiencies in regulation, reporting, network planning and other aspects of the business. While the EnergyAustralia proposal for a change to the transmission boundary did not fix the problem of dual regulation, it represented the most efficient solution within the current framework. Unfortunately, these efficiencies have been denied and EnergyAustralia must operate both parts of its networks within these conditions.

Reviewing the Draft Regulatory Principles

In 1999, EnergyAustralia and TransGrid were regulated by the ACCC for the first time. In the intervening years, Transmission Network Service Provides (TNSPs) in all other NEM jurisdictions have undergone the revenue cap process with the ACCC. This submission0 constitutes the beginning of EnergyAustralia's second period of regulation under the ACCC.

The ACCC is currently reviewing its Draft Regulatory Principles (DRP). Despite the ACCC recently providing EnergyAustralia with an assurance that we will be regulated in a way that is consistent with the current (1999) principles, the ACCC released its "discussion paper" on the Review of the DRP on 29 August 2003.

EnergyAustralia is concerned that the ACCC will be influenced by the analysis contained in the DRP discussion paper when making its decision on the revenue reset. In other words, the "preferred positions" are likely to influence the revenue reset decision made by the ACCC before the ACCC has made a final decision as to whether the new principles will be adopted, and before adequate public consultation has taken place.

The drafting of this submission was completed prior to the release of the DRP discussion paper in order to obtain the Board of EnergyAustralia's endorsement in time to meet the ACCC's request that EnergyAustralia submit its application one and a half months earlier than previously determined. Therefore this submission does not address the issues raised in the DRP discussion paper, as there has been insufficient time to assess and address the issues raised.

EnergyAustralia intends to participate in the public consultation process that has been outlined by the ACCC for its review of the DRP. However, EnergyAustralia reserves the right to submit additional documentation as part of our revenue reset application where it is found that the DRP discussion paper raises new issues that have not been adequately addressed in this submission.

Form of regulation

EnergyAustralia's distribution network, which is regulated by IPART, is subject to a weighted average price cap form of regulation for the regulatory period from 2004-2009. EnergyAustralia strongly supported the move from a revenue cap to a weighted average price cap in distribution as it more effectively provides for revenues to cover costs during times when demand increases above forecast demand. Demand was significantly different to forecast demand during the current regulatory period for EnergyAustralia's distribution business. The weighted average price cap is far superior to a revenue cap in providing incentives for efficient pricing, managing volume risks, providing price stability, and in ease of administration. The revenue cap mechanism that applied during this period did not cater for circumstances where demand was significantly higher than forecast. As a consequence, EnergyAustralia was required to meet higher demand through increased capital spending, but was not able to increase prices to cover increased costs as this would have resulted in recovery of more than the allowable revenue. In fact, due to higher customer numbers, EnergyAustralia's distribution prices were forced down despite rising costs.

EnergyAustralia believes there is a case for consistency between the forms of regulation applied to its transmission and distribution business. However, EnergyAustralia recognises that the ACCC is required under the Code to apply a revenue cap to all transmission businesses. While unable to change the form of regulation before the next regulatory period, EnergyAustralia is eager to investigate the potential benefits of a weighted average price cap for its transmission business in the future. EnergyAustralia believes that the form of regulation should be investigated when the ACCC reviews its regulatory principles.

2. Characteristics of EnergyAustralia's network

Trend towards a summer peaking system

EnergyAustralia's network has experienced significant growth in peak system demand over the current regulatory period, particularly during summer. The marked increase in peak demand has placed pressure on EnergyAustralia's infrastructure. The impact of the rapid growth in summer peak demand has been particularly onerous, as equipment and system ratings are lower during periods of high temperature.

The following table illustrates the variance between forecasts and actual demand, which has had a major impact on network operation and network planning for the next regulatory period.

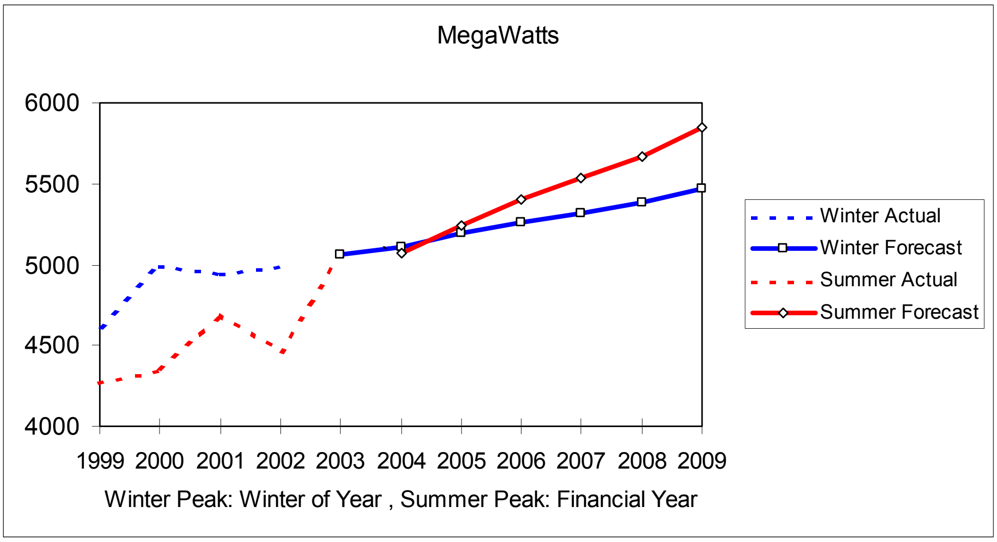
Table 1 - Forecasts and outcomes for energy and peak demand for 1999-2004 period

	1999/00	2000/01	2001/02	2002/03	2003/04	Average
Peak Demand Growth – Winter						
Forecast	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Actual[1]	7.9%	-1.0%	1.0%	2.3%	0.2%	2.1%
Peak Demand Growth – Summer						
Forecast	3.0%	3.0%	2.0%	2.0%	2.0%	2.4%
Actual	1.7%	8.1%	-5.0%	13.3%	0.4%	3.6%
Consumption Growth						
Forecast	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Actual	6.0%	3.7%	0.5%	0.9%	2.1%	2.6%

EnergyAustralia has worked hard during the current regulatory period to improve its forecasting processes. The outcome is considered to be a robust and reliable set of forecasts for the 2004-09 regulatory period reflecting best practice in forecasting methodology.

Peak demand is expected to grow at a rate of 3.5 percent during summer and 2 percent during winter for the period 2004-09. Given that peak demand growth for summer is expected to outstrip growth of peak demand in winter, it will result in the system being consistently summer peaking by the end of the period which has significant implications for network planning and capital works programs. Figure 1 demonstrates the variance between summer and winter global peak demand forecasts for the next regulatory period.

Figure 1 - Global Peak Demand Forecast



EnergyAustralia has included further details about our forecasting process and forecast outcomes in this submission.

Asset condition

EnergyAustralia's network includes an extensive network of underground 132kV cables and overhead feeders supplying the inner metropolitan area of Sydney. Work has been carried out over the last decade including during the present regulatory period to optimise power flows on these cables. Despite this work, this part of the network is now operating at capacity when TransGrid's parallel path is not available. TransGrid and EnergyAustralia are currently

[1] Winter peak demand is calculated on a calendar year basis.

undertaking work to augment this constraint. However, EnergyAustralia believes that during the next regulatory period, the transmission system that services the inner metropolitan area will need further augmentation. This is due to continuous growth of residential accommodation and greater domestic and business demand for electricity generally.

Asset age

EnergyAustralia operates one of the oldest networks in Australia. Much of EnergyAustralia's transmission network was built in the 1960s and some assets date from the 1950s. Hence, many assets will reach the end of their lives during the next decade. EnergyAustralia has included a program of replacement of older assets, targeted in particular to pressure filled cables. However, toward the end of the decade, EnergyAustralia expects to expand the replacement program.

Asset age can also be a key driver of operating expenditure. EnergyAustralia faces increasing challenges in managing and maintaining an ageing network over the next period.

3. Capital and operating programs 2004-2009

Joint planning with TransGrid

EnergyAustralia undertakes joint planning with TransGrid, the other provider of transmission services in NSW, as required by the Code. EnergyAustralia's transmission business also participates in planning discussions with its own distribution business to plan future network augmentations including future capital works and the timing of capital projects.

The planning process is critically important to ensure that the timing of capital works is aligned where possible and that maximum benefit is achieved from augmentations undertaken by TransGrid. The capital program proposed for 2004-09 has been designed in conjunction with TransGrid and is outlined, in brief, below.

Prudence and efficiency in capital spending

EnergyAustralia has reviewed its capital planning process to ensure that our investment decisions are not only prudent under current industry practice, but that the process places EnergyAustralia at the forefront of investment management. With this process, EnergyAustralia can be sure that it will receive the widest benefits from money spent.

EnergyAustralia places great emphasis on the planning and project identification stage because assessment of customers' needs and selection of the best ways to meet those needs exerts the greatest leverage over customer value and cost outcomes. In addition to establishing clear targets, EnergyAustralia selects projects to minimise the whole of life expenditure.

Capital program 2004-09

EnergyAustralia's capital program has two distinct drivers. The first is capital investment driven by demand for network services and capacity on the network. The second is the replacement of ageing assets. Reliability is also a driver of capital expenditure, however, this can be improved by pursuing additional capacity and reducing ageing assets. Table 2 sets out the proposed capital spend on transmission system assets for the period 2004-09.

Table 2 - Total Transmission Capex ($2003/04 millions)

	Financial Years				
	2004/05	2005/06	2006/07	2007/08	2008/09
Demand	12.7	14.3	7.7	9.9	10.8
Replacement	7.5	9.8	29.9	20.7	11.9
Total	20.2	24.1	37.6	30.6	22.7

CBD and Inner Metropolitan Area

EnergyAustralia has a number of committed programs including a substantial body of work associated with the connection of EnergyAustralia's network to TransGrid's new substation at Haymarket in the CBD. Towards the end of the regulatory period, further work will be undertaken in the CBD to avoid over loading of the 132kV system that services the inner metropolitan area. Joint planning with TransGrid is under way in relation to this work.

EnergyAustralia will also build a new zone substation south of the city in Green Square. The construction of this substation is driven by the need to replace ageing 33kV cables and zone substations in the South Sydney area. The substation will also provide additional capacity to meet increasing demand in that area resulting from new developments associated with urban renewal. Since this zone substation will be supplied from 132kV transmission cables interconnecting TransGrid's Haymarket and Beaconsfield West substations, it is regarded as a transmission exit point.

Replacement of ageing feeders within the inner metropolitan area will also take place during the regulatory period 2004-09.

Central Coast

In the Central Coast, load demand is increasing quickly and network augmentation is needed to increase capacity within the area. Upgrading of existing substations in the area will take place during the period and several new feeders will be built to serve demands for new load. Line routes and connection arrangements for proposed developments are yet to be finalised. The classification of proposed work as transmission or distribution will depend on the final arrangement of connections.

Hunter region

EnergyAustralia will also be active in the Hunter region building a new substation at Beresfield and upgrading existing feeders and building new feeders to meet growing demand in the area.

Operating program 2004-09

EnergyAustralia has undertaken a complete review of its maintenance program and has moved from an age/time-based system of maintenance to a condition-based program. The program is designed to optimise the maintenance and replacement of assets. It also delivers benefits including an increased focus on the overall life-cycle costs of assets and the cost of maintenance over an asset's life. It will also deliver a significant and sustained reduction in the level of reactive and breakdown maintenance in the longer term. However, in the short term, the new program requires increased planned maintenance and therefore does not deliver cost savings in the initial stages.

Table 3 - Total Operating Costs ($2003/04 $'000s)

	Financial Years				
	2005/06	2006/07	2007/08	2008/09	2009/10
Forecast Total O&M Expenditure	**24,370**	**25,751**	**26,559**	**27,143**	**27,729**
Maintenance Expenditure	**15,599**	**16,693**	**17,031**	**17,154**	**17,221**
Transmission Subs	6,684	7,177	7,356	7,643	7,504
Zone Subs	2101	2,255	2,310	1,941	2,354
O/H Transmission Lines	1,694	1,776	1,778	1,801	1,739
U/G Transmission Cables	5,120	5,484	5,587	5,769	5,624

Other	**8,771**	**9,059**	**9,528**	**9,989**	**10,508**
Network Communications & Control	4,151	4,109	4,064	4,024	3,986
Other	4,620	4,950	5,464	5,965	6,522

4. Asset valuation

The Code allows the ACCC discretion to determine which methodology it will apply to valuation of TNSPs asset base in this second round of regulation of TNSPs. EnergyAustralia would therefore like to take the opportunity to argue for its preferred approach to asset valuation.

In principle, EnergyAustralia prefers the use of a roll-forward approach to determining the regulatory asset base. This approach significantly reduces the subjectivity associated with other forms of valuation and provides more certainty that prudent and efficient investment will earn a regulatory return over the lives of the assets, provided that appropriate guidance is given by the regulator on an ex ante basis to identify what constitutes "prudent and efficient" investment.

However, before a roll-forward methodology can be supported, it is essential that the starting point be based on an appropriate value of the assets to be regulated. EnergyAustralia believes that the ODRC valuation undertaken in 1999 contained many discrepancies of sufficient magnitude as to be material and therefore believes it to be prudent to perform another ODRC valuation at the outset of the 2004 determination. EnergyAustralia believes that a 2004 ODRC should form the starting point for a roll-forward methodology that should be adopted for the subsequent determination (ie in 2009).

EnergyAustralia has commissioned SKM to undertake an ODRC valuation of its transmission assets. This valuation is based on an ODRC methodology applied to value assets that will be classified as transmission assets on 1 July 2004 and has been calculated at $702m in 2004.

5. Investment framework

In addition to establishing a valuation for the asset base that is accurately reflects its value, EnergyAustralia believes the following components should be reflected in the ACCC's regulatory regime:

- A regulatory period of sufficient length (i.e. five years) in order to provide an incentive to achieve efficiency gains which can then be shared between a business and its customers;
- Certainty that prudent and efficient investments (both past and future) will be recognised in the regulatory asset base (RAB) and will receive a regulatory return on and return of capital. EnergyAustralia proposes an ODRC valuation to establish the initial RAB for the 2004 Determination which forms the basis of a "roll forward" methodology for subsequent regulatory periods;
- Clarity as to what constitutes "prudent" investment on an *ex ante* basis (i.e. prior to the commitment of capital) for inclusion in the regulatory asset base (RAB);
- Clarity as to the means and application of a "roll-forward" methodology for establishing the opening RAB at future regulatory reviews;
- Appropriate allocation of risks between the business and its customers and appropriate compensation for the risks borne by the business;
- Adoption of a robust "pass through" mechanism to create flexibility within a regulatory period to provide investment certainty when confronted with significant and unanticipated changes in circumstances;

- A commercial rate of return within each regulatory period that includes an allowance for working capital; and
- A merit appeals mechanism to create an incentive for regulatory decision-making to be more accountable and transparent.

6. Price outcomes and service standards

Using these principles, EnergyAustralia has calculated that its required revenue over the period 2004-09 is $106.9m in 2004-05 climbing to $127.5m in 2008-09. This revenue stream will allow EnergyAustralia to maintain its aging network and undertake both new capital works and replacement of old elements of the network, thereby ensuring continued high quality of transmission services to our customers.

Table 4 illustrates the components of the revenue requirement.

Table 4 - Components of the proposed transmission revenue requirement ($000)

	2004/05	2005/06	2006/07	2007/08	2008/09
Operating and maintenance	24,891	26,864	28,300	29,541	30,823
Return of capital	14,591	16,001	17,730	19,085	20,485
Return on capital	62,981	64,140	65,605	68,301	70,270
Return on Working Capital	1,062	1,078	1,019	1,133	1,252
Taxation less credits	4,022	4,475	4,726	4,993	5,334
Base Revenue Requirement	107,547	112,559	117,380	123,053	128,166

In constant dollar terms, EnergyAustralia's proposed revenue requirement results in real average network price increases over current prices. However, EnergyAustralia is now in a position where higher levels of capital and operating expenditures are being undertaken.

A "P_0" adjustment is required in 2004, followed by prices that are approximately constant in real terms over the remainder of the regulatory period. As stated above, the major part of the P_0 increase is associated with the inclusion of new assets and assets previously deemed distribution, in effect changing the boundary between transmission and distribution. The equivalent P_0 price change excluding these additional assets but including revaluation of existing assets would be approximately 6.8 per cent nominal or 4.6 per cent real.

7. Service standards

EnergyAustralia is committed to providing high quality outcomes for customers of the transmission network. EnergyAustralia supports the ACCC's proposal to link performance service standards with financial rewards and penalties.

EnergyAustralia's transmission network, however, is very different to those operated by other TNSPs and many of the service standards envisaged for regional TNSPs are not relevant to EnergyAustralia. Therefore, EnergyAustralia is looking forward to working closely with the ACCC to develop relevant standards for EnergyAustralia's network.

8. Conclusion

EnergyAustralia has a growing network of transmission assets. The increasing demand for electricity in Sydney and in the Central Coast region are driving capital works and has lead to an increase in the number of distribution assets that now operate in parallel to TransGrid's network and therefore have become classified as transmission assets.

TransGrid and EnergyAustralia continue to work closely together to ensure that augmentations to the transmission network cater for demand in the future and thereby ensure the most efficient way of meeting customer needs. However, the climate for investing in the transmission network has changed significantly in the past year due to the uncertainty associated with the ACCC's review of its regulatory principles.

EnergyAustralia notes that the ACCC is about to review its regulatory principles. We are concerned that this review may influence the ACCC's decision on EnergyAustralia's revenue reset without being tempered by the opinion and experience of the asset owners within the industry through a public consultation process. EnergyAustralia commends the ACCC for striving to improve its regulatory processes and to deliver transparency in the form of publicly disclosed principles. However, EnergyAustralia must stress that the timing of the review is less than ideal and introduces additional uncertainty to planned investment moving forward. Not only is the ACCC's view on some critical issues not known, it is not clear whether the existing or the revised principles will actually apply to EnergyAustralia and to TransGrid for the 2004 revenue reset.

A INTRODUCTION

EnergyAustralia operates a distribution network that extends from Waterfall in Sydney's south to north of Newcastle and extends in a northwesterly direction to Scone and Barry. However, EnergyAustralia's network contains a small proportion of high voltage transmission assets within parts of the Sydney and Central Coast areas. For this reason, EnergyAustralia is regulated by two regulators – the ACCC for its transmission assets and IPART for its distribution assets.

This submission represents EnergyAustralia's submission to the ACCC for the transmission revenue determination that will apply from July 2004. This submission relates to EnergyAustralia's transmission assets only. However, the format and much of the information contained in this submission is consistent with information provided by EnergyAustralia in our recent submission to IPART as part of its distribution network price determination process.

1. EnergyAustralia's transmission and distribution assets

The National Electricity Code (the Code) defines transmission assets as follows:

> "A network within any participating jurisdiction operating at nominal voltages of 220kV and above plus:
>
> (a) any part of a network operating at nominal voltages between 66kV and 220kV that operates in parallel to and provides support to the higher voltage transmission network;
>
> (b) any part of the network operating at nominal voltages between 66kV and 220kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network."[2]

EnergyAustralia does not own assets that operate above 220kV. However approximately 12 per cent of EnergyAustralia's network assets fall within part (a) of the Code's definition of parallel and supporting assets.

In July 2002, EnergyAustralia applied to the ACCC to deem EnergyAustralia assets rated at 66kV and above (regardless of whether they are in parallel or provide support services) to be defined as transmission assets consistent with part (b) of the definition. EnergyAustralia sought this change to the definition to streamline internal business processes and improve accuracy of financial reporting.

EnergyAustralia has recently received formal notice from the ACCC that it has rejected EnergyAustralia's request for it to deem all assets that operate above 66kV as transmission assets on the following basis:

> "..the request fails to overcome the core problem that EnergyAustralia are currently regulated by both the Commission and the Independent Pricing and Regulatory Tribunal (IPART); accepting this request creates inconsistency between the treatment of EnergyAustralia's assets and those of other distribution companies; accepting this request would create a precedent which could provide an incentive for other distribution companies to submit similar requests; and accepting this request could have an impact on EnergyAustralia's current ring fencing waiver application."

This submission therefore is written on the basis that the current transmission definition continues to apply to EnergyAustralia. However, this raises a number of difficulties during the next regulatory period as the proportion of EnergyAustralia's network assets that are transmission assets will change before the start of the determination period, and change throughout the period. This is due to augmentations that are planned for the transmission network which will cause a number of high voltage assets that are currently part of a radial configuration (and therefore distribution) to operate as parallel and supporting assets and thereby become transmission assets.

The information contained in this submission takes into account all assets that will be considered to be transmission assets on 1 July 2004. Given that there will be a number of changes to the network configuration within the 2003-04 financial year, the recent ACCC

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[2] National Electricity Code definition of transmission network. See Code glossary.

commissioned report that identified EnergyAustralia's transmission assets will not be accurate in 2004.

Regulation by two regulators

EnergyAustralia is the only electricity network service provider operating in the NEM that is subject to regulation by two regulators. There are several other distribution network service providers operating in the NEM that have transmission assets. However, these businesses are either the beneficiaries of a jurisdictional derogation that defines all their assets as distribution, or the assets in question are effectively ignored by the ACCC as they make up a relatively small proportion of their total network assets.

EnergyAustralia is treated in a manner that does not recognise the different circumstances that our network faces. Furthermore, EnergyAustralia's request that the ACCC deem further assets as transmission is already open to other distribution service providers but not pursued because of the costly inefficiencies in dealing with two regulators.

EnergyAustralia recognises the inefficiency in being regulated by two regulators but also recognises the inability of the ACCC to forgo its responsibility to regulate transmission assets under the Code. Faced with the reality of two regulators, EnergyAustralia's request for a change to the transmission / distribution boundary, which was not accepted by the ACCC, represented the most efficient approach within the current framework.

Form of regulation

Being regulated by two regulators also has added complexities as the two regulators apply different forms of regulation to the parts of the network that they regulate. Like all TNSPs regulated under the Code, EnergyAustralia's transmission assets are subject to revenue cap regulation. However, EnergyAustralia's distribution assets are regulated using a weighted average price cap methodology. This divergence between the methods of regulation leads to added complexities for EnergyAustralia. EnergyAustralia therefore has a strong preference for a weighted average price cap to be applied to its transmission business as well.

EnergyAustralia recognises the ACCC's inability to apply anything other than a revenue cap under the current Code at this time. However, we believe that consideration of other forms of regulation should be undertaken during the ACCC's review of regulatory principles.

A more full explanation of the basis upon which EnergyAustralia proposes a weighted average price cap for transmission is included in the Investment Framework chapter.

2. EnergyAustralia and TransGrid

TransGrid is the operator of the high voltage transmission network in NSW that connects the NSW electricity grid to the adjoining states as part of the National Grid. TransGrid, like all transmission network service providers in NEM jurisdictions, is regulated by the ACCC using revenue cap regulation.

EnergyAustralia and TransGrid work closely together to ensure that customers in NSW are provided with network services at world class quality and productivity levels. This close cooperation involves joint planning and coordination of maintenance processes. TransGrid and EnergyAustralia also harmonise development of prices. In fact, TransGrid uses information provided by EnergyAustralia to calculate transmission prices for all locations in NSW on behalf of itself and EnergyAustralia. TransGrid undertakes this role to ensure that both TNSPs operating in NSW implement the pricing principles contained in the Code in a consistent manner. The process for determining transmission prices is set out below.

Pricing process

TNSPs are obliged under the Code to announce the transmission charges on May 15 for the following financial year[3]. EnergyAustralia provides its allowable revenue for the year (as determined by the ACCC) to TransGrid and provides a detailed breakdown of assets used in

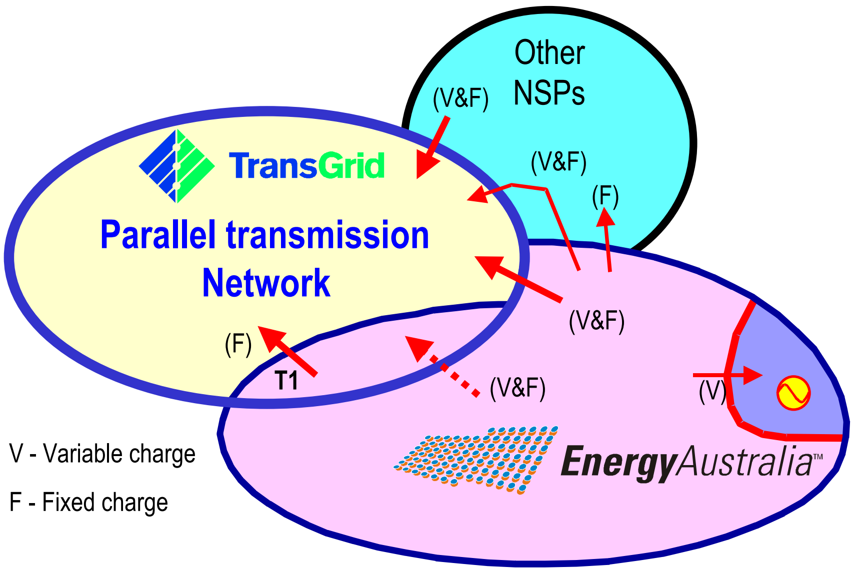
[3] Clause 6.5.7 of the National Electricity Code

the transmission network and up to date information relating to the configuration of the network. Using this information, TransGrid calculates transmission charges for all NSW transmission connection points by adding the annual allowable revenue for EnergyAustralia to its own allowable revenue for the year. Transmission prices typically contain a fixed and variable component[4].

Both EnergyAustralia and TransGrid collect TUoS charges from customers. However, due to the components of the pricing (i.e. fixed and variable), EnergyAustralia collects revenues from its customers that should be directed to TransGrid, and TransGrid collects revenues that should be directed to EnergyAustralia. To ensure that both businesses earn no more than their allowable revenue, there is a net transfer of revenue that occurs each month from EnergyAustralia to TransGrid.

Figure 2 shows the flow of funds between EnergyAustralia and TransGrid. The pink region represents EnergyAustralia's network and the portion that overlaps TransGrid's network represents EnergyAustralia's transmission network. Parts of the EnergyAustralia distribution network border TransGrid's network directly, and other parts border EnergyAustralia's own transmission assets. EnergyAustralia's network also borders other networks from which it purchases network services. These are represented by the blue region and include Integral Energy, Macquarie and Delta[5]. EnergyAustralia pays networks charges to these businesses, and the component of TUoS embedded in these distribution network prices is transferred back to TransGrid.

Figure 2 - Revenue flows between EnergyAustralia and TransGrid



The transfer of funds between EnergyAustralia and TransGrid is a fixed monthly transfer. There is a reconciliation at the end of the financial year if payments for services rendered differ from the forecast amount. Any discrepancy is rolled forward to the next year by adjusting the annual allowable revenue that EnergyAustralia provides to TransGrid to set

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4 The fixed component incorporates the common service and general TUoS charges and the variable component is based on peak and shoulder energy use, and monthly kilowatt demand. Where a TransGrid transmission line enters and exits the EnergyAustralia network, the normally variable component of charges is fixed to avoid double counting of energy flows through the network.

5 EnergyAustralia pays Macquarie and Delta for network services because EnergyAustralia customers are connected directly to their network. EnergyAustralia pays Integral Energy for network services because EnergyAustralia has a large flow into the network from Integral Energy at Carlingford.

transmission prices for the following year. Given the relatively stable nature of flows within the transmission network and the fact that half of each transmission price is fixed, the discrepancy at the end of each financial year is very small, and therefore does not materially affect changes in transmission prices from year to year.

3. Regulatory obligations under the Code

The ACCC regulates transmission networks in all jurisdictions in Australia that are parties to the National Electricity Code. The intent of these arrangements is to provide consistency of regulation across jurisdictions and therefore equality of access to transmission networks for all customers.

The Code sets out the principles that the ACCC must apply in regulating transmission networks. The key principles include, to:

- Promote competition in the provision of network services wherever practicable;
- Facilitate a commercial environment which is transparent and stable, and which does not discriminate between users of network services; and
- Regulate the non-competitive market for network services in a way that seeks the same outcomes as those achieved in competitive markets.

The extensive list of objectives outlined in Chapter 6 of the Code must all be given appropriate weight and consideration. The recent decision of the West Australian Supreme Court in relation to Dr Ken Michael and Epic Energy held that regulators must carefully apply the provisions of the Code and be able to demonstrate that they have properly considered and applied all of the relevant objectives and principles in making Determinations. Regulators face a risk of making errors of law if they do not seek to achieve the Code's objectives for the regulation of TNSP's revenues.

EnergyAustralia makes this submission and outlines a revenue requirement that will support the ongoing performance of our transmission network and ensure prudent management of resources.

4. Structure of the submission

EnergyAustralia's submission on transmission pricing for the period 2004-09 is structured as follows:

Chapter B outlines EnergyAustralia's forecasting process and projections for 2004-09. It outlines the distinctly different uses for energy and peak demand forecasts and shows how the spatial forecasts directly impact on the capital program developed for the period.

Chapter C discusses EnergyAustralia's asset management strategy and new capital governance procedures. These procedures represent best practice analysis of potential capital works projects and actively implements EnergyAustralia's obligations to consider all options including analysis of demand side effectiveness. The section also outlines our maintenance priorities for the transmission system and provides details of how both capital and operating budgets are developed on the basis of joint planning between EnergyAustralia and TransGrid

Chapter D puts forward EnergyAustralia's preferences for an ODRC approach to valuation of assets in 2004. Furthermore it outlines EnergyAustralia's considerations of financial matters including return on assets (WACC), depreciation and other parameters. It also outlines our proposal for a cost pass through mechanism in specific circumstances and our claim for a self-insurance premium to cover liabilities we face for risks borne internally.

Chapter E brings the previous sections of the submission together and outlines the revenue requirement that EnergyAustralia believes is necessary to sustain a world class network and high performance standards.

Finally, Chapter F outlines EnergyAustralia's approach to service standards. It includes our proposed approach to the service standard incentive mechanism put forward by the ACCC.

B FORECASTS

The expected growth of system peak demand is the main driver of the demand-driven capital expenditure program for the 2004-09 regulatory period. This section sets out EnergyAustralia's forecasts of peak demand for the period 2004-09.

The current regulatory period has seen a significant increase in the overall rate of growth of peak system demand, particularly during summer. The marked increase in peak demand has placed pressure on EnergyAustralia's infrastructure. The impact of the rapid growth in summer peak demand has been particularly onerous, as equipment and system ratings are lower during periods of high temperature.

EnergyAustralia has worked hard during the current regulatory period to improve its forecasting processes. The outcome is considered to be a robust and reliable set of forecasts for the 2004-09 regulatory period, reflecting best practice forecasting methodology.

1. Overview of Forecasting Processes

Two distinct sets of forecasts are produced on a regular basis:

- "Spatial" forecasts of peak demand, for each of 170 zone substations, as well as at the subtransmission substation level; and
- "Global" forecasts of coincident peak demand on the overall EnergyAustralia system.

Spatial Forecasts

The spatial forecasts form the key input to the planning of the demand-driven capital expenditure program. The forecasts rely on intensive analysis and local knowledge of historical trends by planning specialists. The following factors are considered in the development of the spatial forecasts:

- Committed future spot loads;
- Expected future spot loads;
- Planned network projects such as changes to load transfer procedures that will affect future spatial loads; and
- Local and regional projections from bodies such as Planning NSW.

Global Forecasts

Forecasts of overall peak demand are prepared as an adjunct to the energy forecasting process. The global peak demand forecasts are based on analysis of assumed trends in the following drivers of electricity consumption:

- Economic activity;
- Residential customer numbers;
- Residential customer characteristics, in particular penetration of air conditioning and space heating appliances;
- Electricity and gas prices;
- Fuel substitution and energy market share trends, including competition from natural gas and solar fuel sources;
- Energy efficiency improvements and environmental impacts; and
- Short-term abnormal weather and day-type impacts.

The global forecasts are indicative only of overall trends, and are used only as an independent logic check of the spatial demand forecasts. Linking the global and spatial forecasts in this way ensures consistency in the assumptions used in both revenue and capital expenditure planning.

2. Review of trends during 1999-2003

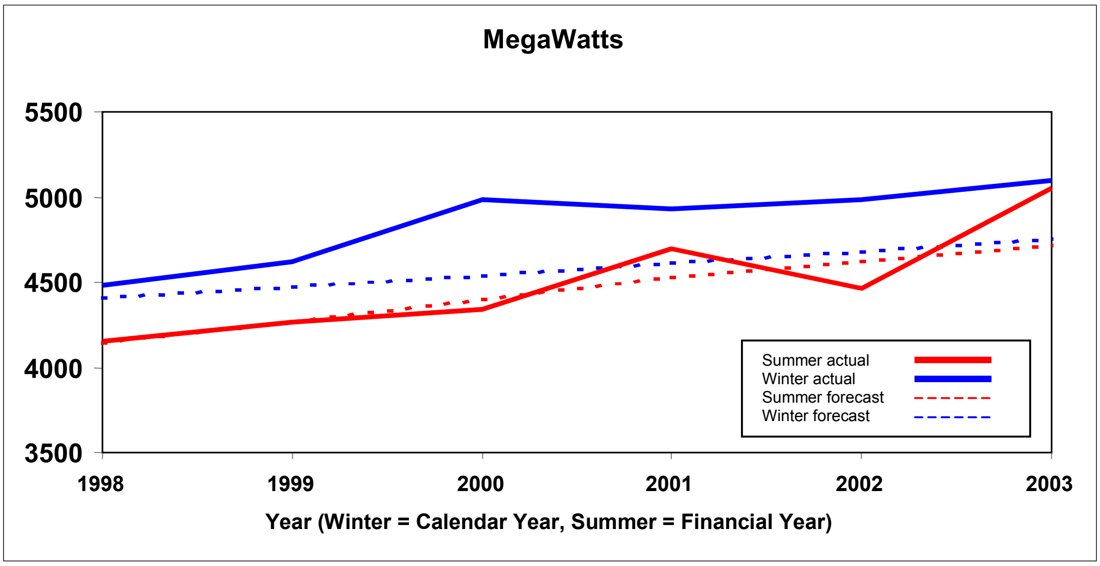
Overall peak demand trends 1999-2003

The market environment in which EnergyAustralia operates has undergone significant changes during the current regulatory period.

In 1998, based on trends that were evident at the time, EnergyAustralia forecast that winter peak demand would grow at 1.5 per cent per annum over the 1999-2004 period. Summer peak demand was projected to grow at the higher rate of 2.5 per cent per annum.

Peak demand has grown considerably faster than forecast, as illustrated in Figure 3.

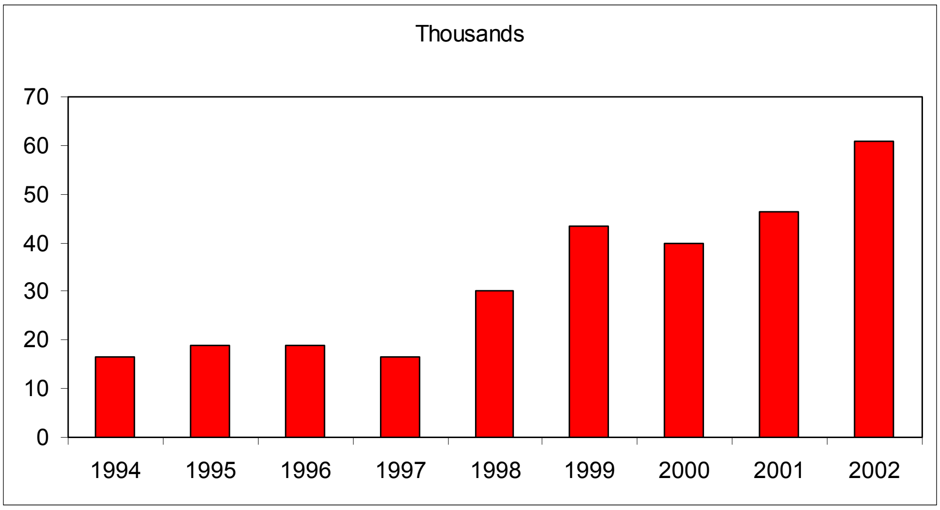
Figure 3 - Peak Demand – Comparison of Actual and 1998 Forecast



Peak demand growth over the 1999-2004 regulatory period is now expected to average 3.5 per cent for summer and 2.0 percent for winter.

The key driver of the higher than forecast summer peak demand growth has been a step increase in the penetration of residential air conditioning appliances since the extremely hot summer of 1997/98. Figure 4 illustrates this step change.

Figure 4 - Estimated Annual Additions to Residential Air Conditioning Stock



Prior to 1998 the trend in new air conditioning appliances was in the range of between 15,000-20,000 air conditioning units per year. Since 1998 growth in new appliances has averaged 44,000 per annum. As a result the penetration rate of air-conditioned residential customers has increased from an estimated 29 per cent in 1997 to 43 per cent in 2002, representing an estimated 570,000 customers with air conditioning.

Penetration of residential air conditioners is projected to reach 58 per cent by 2009, translating to an additional 250,000 air conditioner units connected to the network.

Whilst the major impact of air-conditioning is on summer demand, substantial increases in winter demand have occurred in some established areas, which is believed to be as a result of reverse cycle air-conditioning units displacing other forms of heating in winter.

Review of spatial peak demand trends 1999-2003

Spatial load analysis and forecasting provides more detailed demand growth projections at the township, suburb and regional level, leading to direct identification of capital projects necessary to achieve required network augmentation or expansion.

Analysis of load trends over the 1999-2003 period at the zone substation level indicate the following:

- A strong correlation between aggregated zone average growth rates and the observed global peak demand growth rates detailed above.
- An increasing proportion of zone areas experiencing peak demand in summer.
- The higher than expected load growth and trend toward summer utilisation is dominated by activity in areas located at the fringe of existing urban development, particularly in the Central Coast and Lower Hunter Regions.

Within the present regulatory period, increases in the level of demand above 1997 forecasts contributed to increased levels of capital expenditure. Whilst these primarily affected EnergyAustralia's distribution business, major increases in transmission expenditure resulted from new projects (such as the establishment of Beresfield substation) and the acceleration of previously identified projects (including Macquarie Park zone substation and work associated with the establishment of TransGrid's Haymarket substation).

Figures 5 and 6 below provide a comparison of regional zone growth rates and trends toward peak summer utilisation over the current regulatory period and clearly illustrate the historical basis for increasing demand driven expenditure in both the Central Coast and Lower Hunter Regions.

Figure 5 - Average Zone Peak Demand Growth 1999 to 2003 – Comparison across Regions

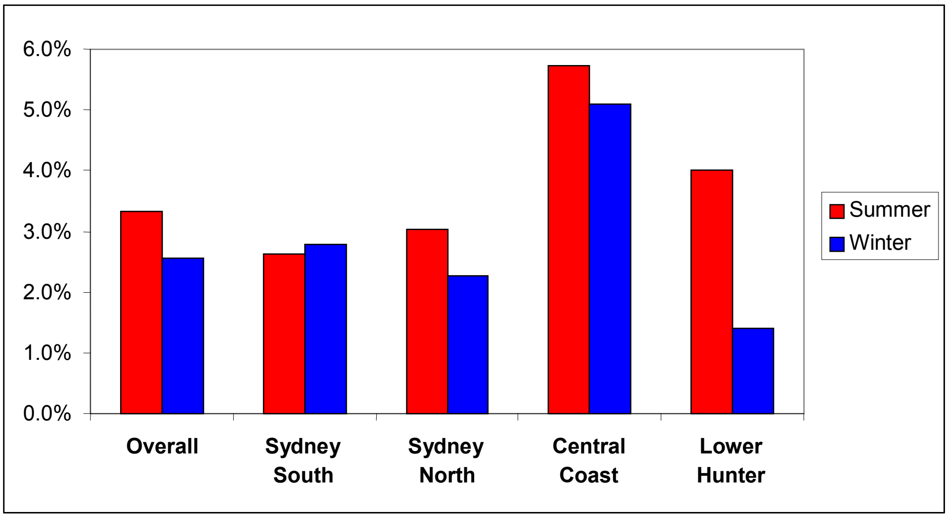
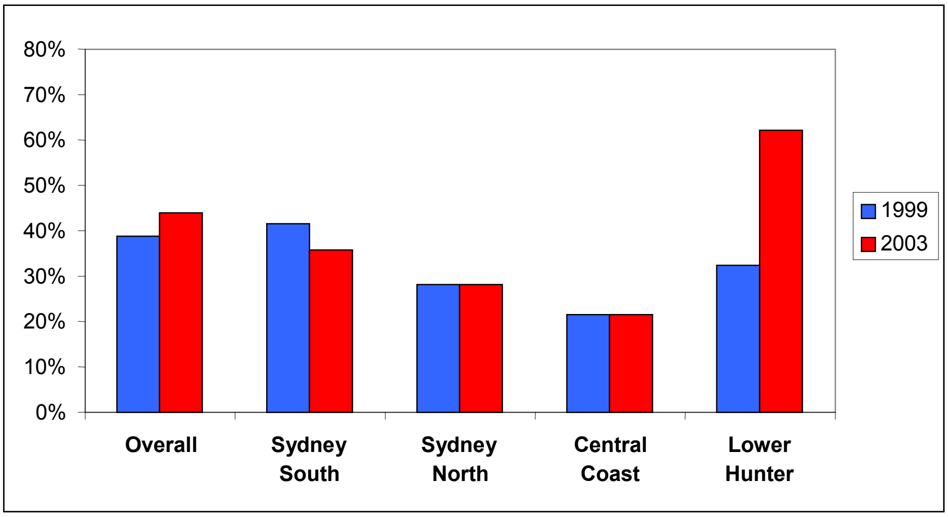


Figure 6 - Change in Proportion of Summer Peaking Zones 1999 to 2003 – Comparison across Regions



As mentioned, the increased growth and trend toward summer peak utilisation is dominated by activity in the urban fringe areas, specifically, the Central Coast and Lower Hunter regions. These trends might be explained by an increased penetration of air-conditioning in developing residential areas and the broad generality that new residential development now tends to occur to the west of the existing urban areas where extremes in seasonal temperatures are more prevalent.

These observations have significant implications for future demand-driven capital expenditure compounded by the following factors:

- Fringe areas generally have limited existing network infrastructure and require increased network expansion in order to provide necessary capacity and supply security.

- The opportunity for providing cost effective capacity augmentation in conjunction with aged asset replacement projects is often very limited in fringe areas.
- Equipment throughput ratings are often significantly lower during summer.
- For a given peak load, risk levels are generally higher in summer due to the broad afternoon peak characteristic.

Projects needed to service these expanding areas represent a significant proportion of demand driven capital expenditure over the current and future regulatory period.

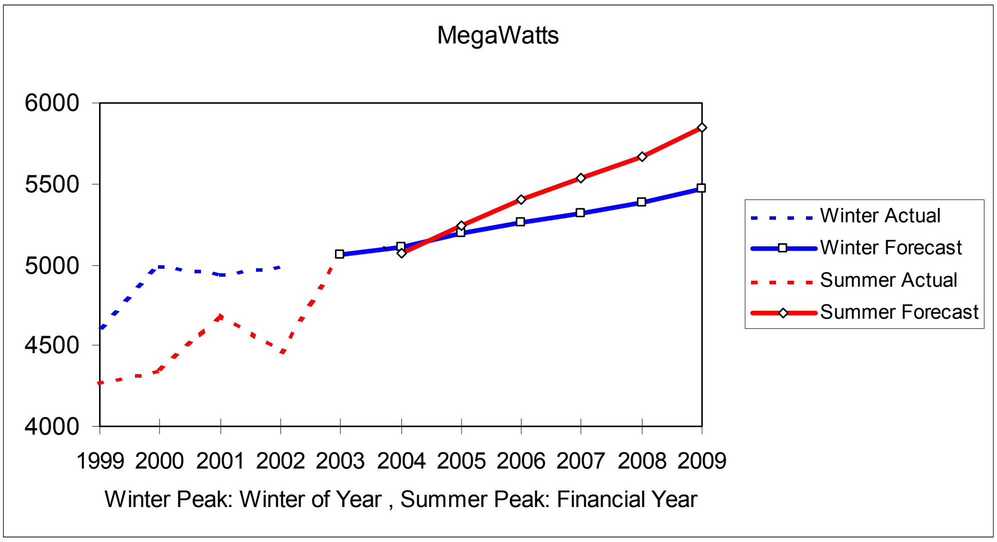
It is worth noting that the main expanding fringe areas of Greater Sydney Region are generally not within the EnergyAustralia franchise area.

3. Forecasts for 2004-2009 regulatory period

Global Forecasts

The recent experience whereby summer peak demand has significantly outgrown winter peak demand is expected to continue over the 2004-09 period. Summer peak demand is forecast to grow at an average 2.9 percent per annum, compared with an expected 1.4 percent growth in winter peak demand. Figure 7 illustrates the global forecast.[6]

Figure 7 - Global Peak Demand Forecast



The forecast differential in seasonal peak growth is such that given normal weather conditions, the network is expected to become summer peaking during the next year or two. However, due to the sensitivity of peak demands to weather deviations, it is possible that the summer peak demand could exceed winter peak demand as early as 2003/04. What is clear is that we are currently experiencing the changeover between winter and summer peaking and that by the end of the 2004-2009 regulatory period, EnergyAustralia's network will be summer peaking.

This trend is likely to drive increasing levels of capital expenditure beyond 2009.

[6] It should be noted that loads associated with BHP and the Capral Smelter are not included in the global forecasts. These loads are flat industrial loads that do not impact on forecasts of peak demand growth rates.

Spatial Forecasts for 2004-2009

The spatial load trends established over the current regulatory period are forecast to continue over the 2004 to 2009 period.

The anticipated overall average zone substation growth rates correlate with anticipated peak demand figures. However, the forecasts indicate an overall increase spatial zone growth variance from approximately 0.2 per cent to 0.75 per cent.

The figures below provide the 2004-2009 projected comparisons of average zone growth and seasonal utilisation for regional and fringe/non-fringe areas similar to those provided for the 1999-2003 period.

Figure 8 - Average Zone Peak Demand Growth 2004 to 2009 – Comparison across Regions

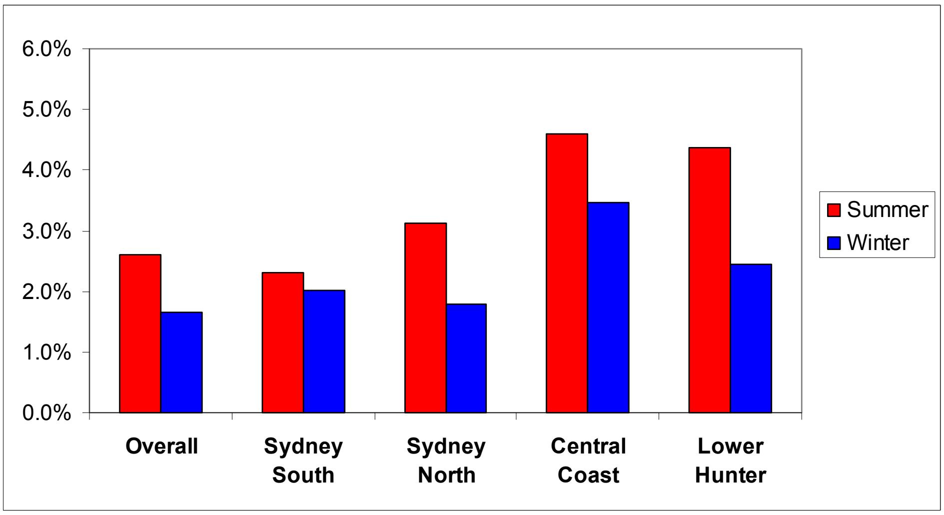
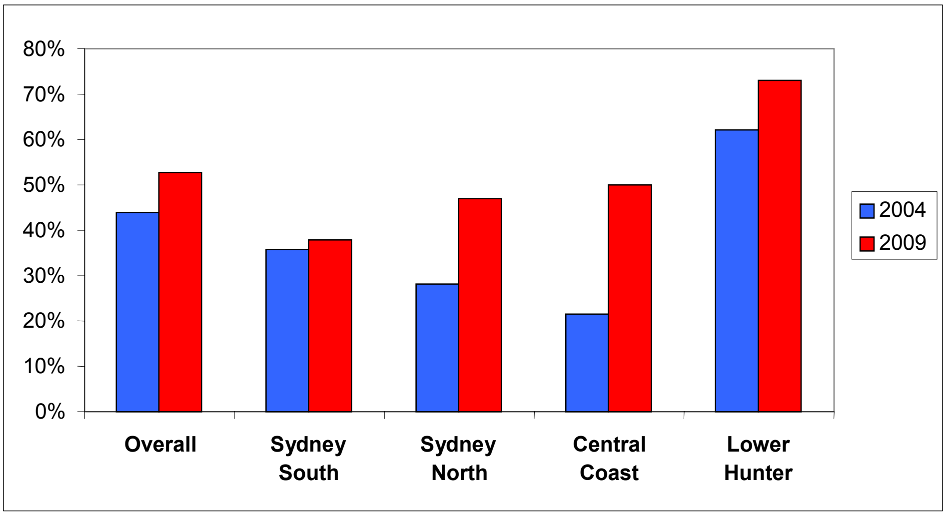


Figure 9 - Change in Proportion of Summer Peaking Zones 2004 to 2009 – Comparison across Regions



Comparison with the 1999-2003 data indicates the following:

- Continued average zone substation growth in line with projected overall peak demand growth.

- Similar projections for zone substation summer growth across regions (however with some marginal easing of growth in the Central Coast).

- Increasing trend toward summer peaking in all regions except the Lower Hunter where this trend will start to saturate (as most zones will become summer peaking). The trend toward summer peaking is expected to be highest in the Central Coast followed by Sydney North.

- Increased divergence of load growth between the urban-fringe and non-fringe areas is anticipated, driven largely by increasing summer utilisation in the urban-fringe areas.

The direct impacts on demand driven expenditure on the transmission system are seen principally in the inner metropolitan area where the magnitudes of existing loads are such that substantial new capacity is required to meet even medium levels of growth, and in Western Newcastle where existing transmission assets are ideally located to support load growth in these areas.

On the Central Coast it is anticipated that demand driven transmission expenditure by EnergyAustralia can be deferred until after 2009. However, substantial augmentation of the distribution system[7] and of TransGrid's system will be required in this area between 2004 and 2009.

[7] A major Central Coast project, the uprate and conversion of Berkeley Vale substation to 132kV operation, may be either transmission or distribution depending on its final 132kV connection arrangements. It has been categorised at this stage as distribution.

C ASSET MANAGEMENT

1. Introduction

The 132 kV supply to most of EnergyAustralia's distribution area in Sydney is provided by an interconnected 132 kV network linking TransGrid's 330/132 kV substations at Beaconsfield West, Sydney North and Sydney South. Load flows through this network have been optimised over the last decade through network re-arrangements and the use of series reactors to control the transmission of load current.

The network is presently in a situation where the loading on the interconnected network is approaching the capacity of the system when TransGrid's Cable 41 is out of service. Work is presently in progress by TransGrid to install a 330kV cable between Sydney South and Haymarket to address this issue.

Much of EnergyAustralia's 132kV system is comprised of underground cables. The majority of this infrastructure was installed about 25 years ago and some important system elements are more than 40 years old. Isolated parts of the cable system require replacement in the short term. However, it is anticipated that some major cables may require retirement/replacement within the next decade.

It is forecast that by 2007-2009 the transmission system supplying the Sydney CDB and inner suburbs will require further augmentation. EnergyAustralia and TransGrid are presently involved in planning to address this issue. Deferral of this work may be possible through the use of demand management or co-generation.

2. Asset Investment

Over the last two years EnergyAustralia has made major improvements at all levels of its capital investment process, from forecasting through engineering criteria to overall capital planning and implementation governance. As a result, the network capital investment strategy is now designed to achieve specific outcomes at lowest sustainable cost.

The Capital Expenditure Process Provides a Transparent Relationship between Expenditure and Outcomes

EnergyAustralia has defined a series of measures and targets for its total Network business. The majority of these targets relate to delivering appropriate outcomes for customers, including appropriate quality of supply and the ability to support new connections. Targets have also been established in areas such as health, safety, and environmental compliance. These targets are aligned with the requirements of the National Electricity Code and in accordance with good industry practice and reasonable customer expectations.

As a starting point for capital expenditure planning, EnergyAustralia has assessed the future outcomes that would eventuate (including outcomes for customers) if no capital expenditure were undertaken. A detailed assessment has been made of the impact of load growth, progressive age-related deterioration, number of new customers wishing to connect to the network, etc. Clearly, without new capital expenditure, projected outcomes would deteriorate progressively; hence investment is required to achieve appropriate performance and compliance.

All of EnergyAustralia's proposed network capital investment has been designed to achieve the target outcomes. The contribution from each capital expenditure option from both the transmission and distribution businesses has been assessed and the best combination of investment options has been selected to achieve target outcomes in each scenario. Rather than relying on traditional planning criteria (which in some cases relate only loosely to performance outcomes), EnergyAustralia has quantified the impact of each capital expenditure proposal on the target customer outcomes.

At the distribution level, EnergyAustralia is able to adjust the capital expenditure portfolio to target different outcomes. If expenditure levels are changed, EnergyAustralia is able to identify the optimum set of outcomes that can be achieved within available funds. To increase transparency between expenditure and outcomes, EnergyAustralia developed capital expenditure scenarios that range from service deterioration (if capital is constrained), maintenance of service standards (the Base Case) and various scenarios for improvement of specific customer outcomes.

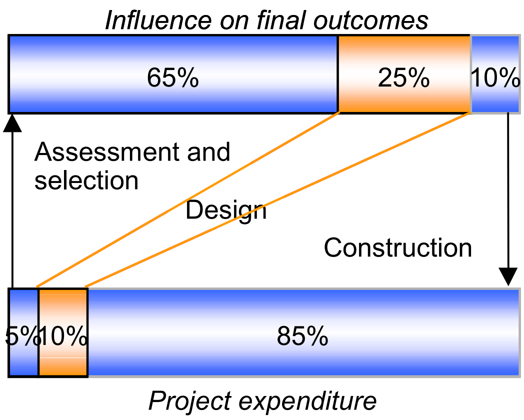
For its transmission network, EnergyAustralia has considered high and low demand growth scenarios as variations from the base case. We have also considered the impact of TransGrid's program and delivery of planned capital works on EnergyAustralia's capital program. This is particularly relevant in the inner metropolitan area where joint planning with TransGrid is critical to the efficient development of EnergyAustralia's network.

This process of developing scenarios for capital works provides flexibility to cater for the changes in priorities that inevitably arise, without sacrificing capital efficiency.

The Capital Expenditure Process Principles

EnergyAustralia's capital planning process is designed to identify the most efficient ways of meeting the targeted outcomes for the network business. We place great emphasis on the planning and project identification stage, because assessment of customer needs and selection of the best ways to meet those needs exert the greatest leverage over customer value and cost. Typically, two-thirds of the influence on final outcomes is determined by assessment and selection, even though only a small proportion of the actual spend occurs in these stages. This concept is illustrated in Figure 10.

Figure 10 - Impact of Capital Expenditure Stages on Outcomes



In addition to establishing clear targets, EnergyAustralia has adopted several other key principles to ensure efficient capital project selection. These include the following:

- Processes for forecasting customer needs are objective and stable. Demand forecasting is based on actual historic growth plus all relevant data that influences the underlying growth trend;

- Capital projects are selected to minimise whole-of-life expenditure, consistent with meeting target outcomes and ongoing customer needs, by considering operating and capital expenditure over the life cycle of the asset. Capital expenditure is also tested against industry benchmarks;

- All relevant options are considered in deciding how to meet the performance targets, including alternative network capex proposals, non-network and non-capital alternatives; and

- There is a robust selection process that explicitly trades off alternative expenditure options using quantified estimates of project costs and benefits (against the business performance targets), to identify the portfolio of projects that minimises the cost of achieving desired performance.

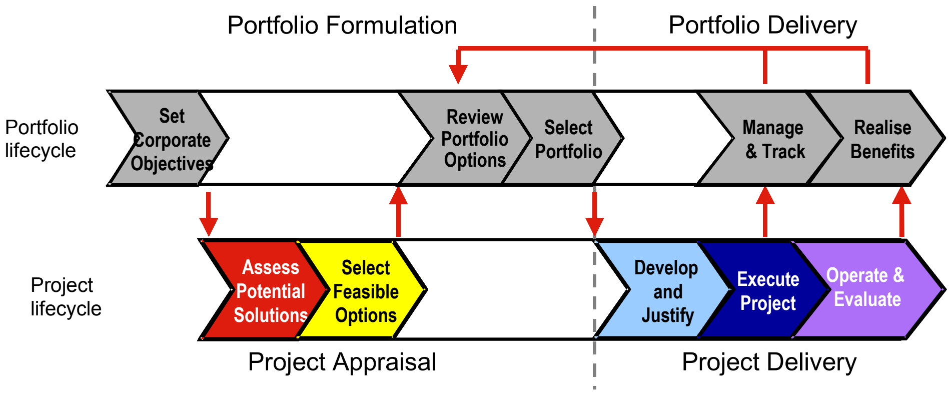
Having selected the most efficient set of capital projects, EnergyAustralia ensures efficiency in delivery by a range of methods including a 'gating' process to ensure the original justification remains valid (re-submitting the project to the selection process if updated estimates of costs and/or benefits deteriorate materially); use of best practice tools for project reporting and risk management; and post-implementation reviews to enable continuous improvement.

The Capital Expenditure Governance Process

EnergyAustralia's capital governance process provides continuous review and assurance that capital prudence and efficiency are being achieved.

The process for selecting and delivering capital expenditure recognises that individual projects and the overall capital portfolio need to be managed and governed separately. This is illustrated in Figure 11.

Figure 11 - Capital governance requires visibility and control via decision gates both for individual projects and the overall portfolio



EnergyAustralia has established clear decision criteria and sign-off responsibilities between each stage in the capital expenditure lifecycle – both for individual projects and the full capital portfolio. This ensures that capital funds are only committed when they meet all criteria for prudence.

In summary, the process features:

- Establishing clear outcome objectives and targets for the Network business;
- Quantifying current and projected needs, and considering all feasible options to address these (including non-capital options);
- Centrally reviewing the available options against overall targets, and selecting a portfolio of capital projects and other options that will deliver the required outcomes in the most efficient manner;
- Further developing individual projects to ensure that updated cost/benefit estimates continue to justify their place within the portfolio; and
- Managing the implementation of each project, and simultaneously tracking and adjusting the overall portfolio to re-optimise future expenditure in the light of up-to-date information on needs and resources.

- All current and new projects are prioritised to achieve the targets in the most efficient way;
- Project options (i.e. approach, delivery, scope and timing) are identified, analysed, assessed and reviewed to enable the development of a portfolio that best meets the objectives. This includes the investigation and analysis of demand management options;
- 'Owners' at each stage in the lifecycle are accountable for delivering the required outcome;
- Each stage of a project is transparent and verifiable and is subject to an assurance check before the project moves to the next stage;
- The portfolio of projects is regularly reviewed and adjusted in order to ensure that it delivers the target objectives as efficiently as possible, given current customer needs and resource constraints;
- Funding of projects is conditional upon the achievement of targeted outcomes for both customers and the shareholder. Any material change that impacts on the achievement of these objectives requires the project to be resubmitted for approval;
- The risk and returns associated with a project are quantified to ensure that the portfolio can be optimised;
- The portfolio comprises projects over multiple years including the current year's forecast, next year's budget and a 5-year forward view; and
- The governance framework is as simple as possible consistent with the need to ensure prudence and understand the implications of decisions made.

Application of these features enables EnergyAustralia to be confident that the capital expenditure forecasts are prudent and efficient. More detail of the governance process is presented at Attachment 8.

Growth Driven Capital

EnergyAustralia operates 132kV and 66kV transmission networks that provide support to TransGrid's network. Until 1 February 2000 EnergyAustralia's entire network was classified as a distribution network for the purposes of the NEC. From 1 February 2000 parts of EnergyAustralia's system became transmission assets and consequently EnergyAustralia became both a Transmission Network Service Provider (TNSP) and a Distribution Network Service Provider (DNSP).

As a TNSP EnergyAustralia is required to carry out an annual planning review with DNSPs connected to its transmission system in accordance with Clause 5.6.2 of the NEC. EnergyAustralia as a DNSP is involved in annual planning reviews with both its own transmission business and TransGrid. Where the necessity for augmentation or extension is identified in this review, joint planning must be undertaken to determine plans that can be considered by code participants and interested parties. Regular meetings are conducted between TransGrid and EnergyAustralia planners to ensure that anticipated works are planned and implemented in a timely manner consistent with the wider strategic aspirations of the two network businesses.

Emerging constraints are documented in the Annual Electricity System Development Review (AESDR) which is publicly available from EnergyAustralia's website. The AESDR scope is all of EnergyAustralia's prospective growth driven capital works and separately identifies those works related to the deemed transmission system (ie the AESDR includes the National Electricity Code (Code) required Annual Planning Report).

Investment Criteria

It is a responsibility of EnergyAustralia to ensure that the network provides a supply of adequate reliability and quality in accordance with the requirements of the National Electricity Code.

Major infrastructure development projects at EnergyAustralia are assessed through the Value Management process in accordance with the Australian/New Zealand standard AS/NZS 4183:1994. At EnergyAustralia this process includes the consideration of alternatives to network construction such as demand management.

The assessment of DM options forms an integral part of capital governance process and provides EnergyAustralia with assurance that capital prudence and efficiency are being achieved in assessing opportunities for DM.

Schedule 5.1.2.2 of the Code specifies a range of possible minimum service standards that may be applied to a power system taking account of specific design, locational and seasonal influences that may affect performance. EnergyAustralia has developed guidelines that indicate the expected performance standards that should be applied in different situations. These guidelines act as a filter that indicates the need for further action or analysis. These guidelines are listed below.

Apart from Code requirements, EnergyAustralia must comply with jurisdictional requirements set out in the NSW Demand Management Code of Practice (DM Code) and any development approval criteria imposed by determining authorities or PlanningNSW under the EPA Act. The DM Code was developed to give guidance to distributors on satisfying their electricity distributors licence requirements[8]. EnergyAustralia is currently participating in the review of the DM code being conducted by the Ministry of Energy and Utilities. EnergyAustralia was required by a condition in its licence to have in place a formal process for providing information 'to the market' that might facilitate non-network supply augmentation options. There is a formal obligation to consider such options in an open and transparent manner - on the same basis as our own network augmentation options.

A significant example of DA[9] Approval outcomes associated with the jointly planned cable tunnels required for augmenting supplies to the Sydney CBD, is the PlanningNSW determination that TransGrid and EnergyAustralia jointly fund a $10m Demand Management fund and follow specified rules for its application. This fund is aimed at addressing the lack of information and uncertainty that existed during the planning approval process over the potential and extent of DM as a viable alternative to the supply side solution.

EnergyAustralia is continuing to improve and refine its practices and processes in identifying evaluating and implementing viable DM opportunities. For the next regulatory period EnergyAustralia's DM initiatives will be focused primarily on distribution investments. These initiatives include:

- introducing distribution pricing and products which are aimed at signalling underlying costs;
- implementing and refining current DM identification and investigation processes; and
- conducting a series of "learn-by-doing" projects under IPART's regulatory framework for Distribution; and
- participating in the joint EnergyAustralia/TransGrid/PlanningNSW $1 million Demand Management and Planning Project.

In general, viable demand management for transmission assets can prove more difficult than for distribution assets as:

- Transmission energy flows are less localised, and hence demand management initiatives more difficult to target to specific areas

[8] It should be noted that for the purposes of NSW licensing, EnergyAustralia's transmission network falls within the definition of its distribution network and is therefore subject to the same licensing requirements.

[9] Development application

- Transmission load is more aggregated than distribution loads and hence any reduction in peak load growth required for a capital deferral is likely to be large and hence more difficult to deliver than smaller localised distribution driven DM.

IPART in its *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report October 2002* has recognised the need to “tilt the playing field” in favour of DM options and EnergyAustralia supports such an approach until a mature market emerges for the provision of DM services.

In a recent response to IPART’s *Draft report on Reducing Regulatory Barriers to Demand Management for the 2004 –09 regulatory period,* EnergyAustralia has proposed an overall incentive based approach to the adoption of localised DM initiatives supported by a cost based recovery of specific “Learn-By-Doing” DM projects. EnergyAustralia encourages the ACCC to adopt a similar approach to any transmission based DM initiative identified during the next regulatory period.

Reliability

The reliability of a system is its ability to continue to supply customers given the finite probability of outages of components of the system. The reliability planning criteria are intended to ensure that during first contingency outages:

- major loads will continue to be supplied;
- voltage levels will remain within acceptable limits; and
- system ratings will not be exceeded.

The planning policy used by EnergyAustralia involves a mix of deterministic and risk management criteria which vary with the magnitude and nature of the network load.

132kV Networks specific investment criteria

The minimum planning criteria used on the present 132kV system is a deterministic (N-1) criterion for 132kV lines and transformers. This means that the forced or planned outage of any single system element will result in:

a) at most a momentary interruption to customers;

b) acceptable voltage levels being maintained on the secondary busbars of transformers; and

c) loading of the remaining network elements in service staying within accepted limits.

Within urban areas substantial loads are supplied from double circuit overhead lines or from double circuit cable banks. In these cases double circuit outages are considered to be credible contingencies and backup emergency supply is normally provided. The capacity of back up provided varies with the nature of the load and should be no less than the loading which is exceeded:

- 65 per cent of the time for predominantly domestic loads with improvement to 25 per cent of the time subject to cost benefit investigation;
- 25 per cent of the time for loads with significant industrial or commercial components; or
- 7 per cent of the time for Sydney CBD loads.

This backup may be achieved through interconnection at voltages lower than 132kV.

The redundancy provided in customer connections is in accordance with customer requirements.

Improved Reliability Criteria for 132kV System

In recent years, the simultaneous outage of TransGrid's 330kV Cable 41 (supplying TransGrid's Beaconsfield West Substation) and other 132kV elements has not been included in the reliability criteria. Due to the large number of critical elements involved it was decided to expand the reliability criteria used in planning the supply to the CBD and inner suburbs of Sydney to be more in line with international practice by considering:

a) a simultaneous outage of Cable 41 (330kV cable supplying TransGrid's Beaconsfield West substation) and any 132kV feeder or 330/132kV transformer; and

b) an outage of any section of 132kV busbar.

This extension of the criteria has been endorsed by the ACCC as an outcome of the regulatory assessment undertaken for the imminent second 330kV cable providing increased bulk supply capacity to the inner Sydney area and its associated works.

Upgrade Criteria

When studying the operation of the interconnected network, loading is regarded as unsatisfactory when 330/132kV transformers are loaded to beyond their cyclic overload rating and feeders are loaded to more than 95 per cent of their cyclic rating.

This 95 per cent decision criteria has been adopted to provide an allowance for:

- statistical variations in loads above forecast. (The forecasts used in EnergyAustralia's studies are based on long term average maximum temperatures and variations in temperature from year to year result in actual loads regularly being different from the forecast).
- variations in generator dispatch. Variations in the dispatch of generation in response to the market can vary the balance of load flows between TransGrid's Sydney South and Beaconsfield West Substations which can impact on load flows in the interconnected system.

Zone substations investment criteria

There are several zone substations (132/11kV) which form an integral part of the transmission assets. These zone substations are planned using deterministic (N-1) criteria for transformers.

Where supply system augmentation involves major expenditure, risk management is used to defer expenditure. Development work is undertaken only if either:

- the firm rating of the substation is forecast to be exceeded more than 1per cent of the time or
- the annual probability of failures which require load shedding to prevent equipment damage exceeds 1 per cent.

Asset Condition/Performance Driven Replacement Capital

Network Condition and Age

Apart from growth and the associated capacity augmentations, there is a requirement for capital expenditures to ensure the maintenance of satisfactory asset and network performance.

EnergyAustralia has the oldest network in Australia. There is clear evidence that assets become more costly to maintain as they age. Indeed, the single most important driver of increased capex and opex over the 2004-2009 period is the aging of assets and the consequent need to trade-off replacement capital and operating expenditures.

Replacement of Assets

Generally assets in all categories are replaced on assessment of their ability to continue their technical function in a safe, reliable and environmentally sensitive manner. For each asset category replacement decisions are generally made based on the application of condition assessment criteria using data from condition monitoring surveys.

All identified replacement projects and programs are categorised into asset groupings and sub-categorised into asset types within an asset replacement database.

The assessment of condition is carried out using various methodologies dependent on the asset type. For example, 132kV underground cables are assessed according to their history of failures and oil and paper analysis.

The replacement capital expenditure program is formulated primarily on the grounds of improving the safety, reliability, environmental sensitivity and condition of the assets. Age is used as a surrogate for condition but is only a secondary consideration in determining the priorities on projects. Therefore, the replacement capital expenditure is not necessarily reflective of the age profiles but will certainly have the effect of reducing average system age.

There are known problems with critical components of the 132kV oil and gas filled cable system. These include oil leaks and problems with the joints and sheath deterioration of specific feeders.

None of the projects contained in the following report have a material inter-network impact.

3. Proposed Transmission Capital Expenditure Program

The following tables summarise EnergyAustralia's transmission capital expenditure program as proposed for the period 2004-09. They provide total figures as well as a breakdown of projects driven by demand and replacement respectively.

Table 5 - Total Transmission System Capex ($2003 millions)

	Financial Years				
	2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Demand	12.7	14.3	7.7	9.9	10.8
Replacement	7.5	9.8	29.9	20.7	11.9
Total System	20.2	24.1	37.6	30.6	22.7

Table 6 - Projects Primarily Involving Demand Related Expenditure

	Financial Years				
	2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
Supplying increasing demand in Inner Metropolitan Sydney	2.0	10.1	6.4	8.6	9.4
Supplying increasing demand – West Wallsend	0.0	0.0	0.3	0.7	1.4
Supplying increasing demand in the East Maitland/Tarro Corridor*	5.6	0.3	0.0	0.0	0.0
Provision of additional 132kV capacity in the Lower Hunter *	5.1	3.9	1.0	0.5	0.0
TOTAL	12.7	14.3	7.7	9.8	10.8

* Expenditure projections based on percentage of total project attributed to Transmission

Project expenditure contains both Demand and Replacement components

Table 7 - Projects Primarily Involving Replacement Related Expenditure #

	Financial Years				
	2004/05	2005/06	2006/07	2007/08	2008/09
Feeder 908/9 replacement	0.4	2.0	23.7	10.0	0.0
Ourimbah Refurbishment	0.0	0.5	2.5	7.0	6.1
Completion of Green Square zone and its later augmentation	6.2	1.3	0.6	2.0	0.4
Replacement program for transmission substations*	0.0	2.6	1.5	0.6	3.9
TOTAL	6.6	6.4	28.3	19.6	10.4

* Expenditure projections based on percentage of total project attributed to Transmission
# Project expenditure contains both Demand and Replacement components

Sensitivity of Expenditure to Changing Demand Forecasts

The capital expenditure projections above are based on an expected rate in summer demand of 2.9 per cent per annum. The basis for this forecast is discussed in Section 2. Since demand related expenditure is dependent on the rate of growth in demand, capital expenditure will vary if growth in demand changes from the medium forecast.

Of the four major projects involving demand related expenditure, it is expected that only two will vary with changing demand, West Wallsend zone substation and supplying increasing demand in inner metropolitan Sydney.

- Sydney Metropolitan area

  Some deferral of expenditure associated with augmentation of capacity in the inner metropolitan area is expected if summer demand increases at a lower rate than forecast. No significant increases in expenditure are expected if load growth increases as project planning and approval times would prevent any significant advancement of work.

- West Wallsend substation

  Timing of West Wallsend substation may change if the rate of increase in demand varies from the medium forecast. Deferral by one year may be possible under a low demand scenario, whilst advancement would be required if demand growth increased.

There is no scope to further accelerate the other two major demand related programs in the Hunter. Loading is presently at a level that the project deferral would not be possible if demand growth slowed. Hence this expenditure for the remaining two projects is insensitive to changes in forecast demand growth.

The above factors indicate that during the next regulatory period (2004-9) overall capital expenditure may decrease by a maximum of $10m if growth in summer demand falls to 1.6% per annum. An increase in the rate of demand growth to 3.85 per cent per annum is likely to result in an increase of $6m in overall expenditure over the five year period.

Sensitivity to New Customer Connections

It is possible that transmission connections may need to be provided for several large customers in the period 2004-2009. Whilst there are no committed customer projects requiring transmission connection, EnergyAustralia has had several inquiries which could potentially proceed during the next regulatory period. Whilst details of these projects such as timing and connection arrangements are not yet known, it is likely that the major costs associated with these projects will be funded by capital contributions. Likely projects which have a greater than 50% chance of proceeding include:

- 50MVA on the Eastern Suburbs – 60% probability of transmission supply before 2009
- 40MVA on the Central Coast – 70% probability of transmission supply before 2009

Estimated capital contributions for these projects have been included in requested spreadsheets.

Anticipated Projects 2004-2009

2003-2005 – Establishment of Green Square Zone Substation - $24m [10]

EnergyAustralia has identified the need to replace an existing zone substation at Alexandria and associated 33kV cables with a new substation known as Green Square. This new substation will form a connection point between EnergyAustralia's distribution and transmission networks.

This work is driven by the need to:

- retire the existing infrastructure at Alexandria substation which has reached the end of its service life
- provide capacity to allow the loading at Mascot zone to be reduced in 2007 to facilitate its reconstruction
- provide capacity to meet long term load growth in the South Sydney area.

The firm capacity of two substations adjacent to Alexandria will be exceeded in Mascot in 2008 and in Zetland in 2009.

Additional capacity provided by Green Square substation will be used in the long term to reduce loading on the above substations, enabling them to supply full load during first contingency outages in accordance with Schedule 5.1 of the Code.

Whilst the project will provide capacity for future load growth, project timing is driven by the need to replace ageing distribution infrastructure.

The alternative to establishing Green Square substation would be to rebuild or replace the existing Alexandria zone substation with a 33/11kV zone. The work would include the installation of more than 30km plus of 33kV cable to replace existing 33kV cables linking Alexandria to Bunnerong sub-transmission substation. The renewal of 33kV construction in an area of such high load density is not a cost-effective alternative to 132kV construction.

2005-2007 – Replacement of Feeder 908 and 909 - $36m

Feeders 908 and 909 are gas filled cables running between Canterbury and Bunnerong. These cables were commissioned in 1956. Refurbishment of many of the joints on this cable was carried out in the late 1990's following a number of extended outages on these circuits. Further failure of this circuit occurred in late 2002, which resulted in the circuit being out of service for more than 3 months.

It is planned to advance the replacement of these circuits to 2007. It is likely that these cables will be replaced with two new cables running between Kurnell and Bunnerong. Whilst this work is driven by the need to replace ageing cables, the new circuits will provide an increase in capacity over the existing cables.

2006-2009 – Augmentation of Inner Metropolitan System - $36m

Action will be required between 2006 and 2009 to avoid overloading the interconnected 132kV system supplying the inner metropolitan area. The likely constraint in this network will be loading on TransGrid's Cable 41 when the proposed Cable 42 is out of service. Joint planning to alleviate this constraint is presently in progress. Options include:

- optimisation of Power flows in EnergyAustralia's network through the installation of series reactors and phase shifting transformers;
- establishment of an additional TransGrid 330/132kV substation;

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[10] Note: Substantial expenditure is expected to occur prior to the start of the regulatory period.

- local generation; and
- DSM.

In the short to medium term, optimisation of power flows by EnergyAustralia in conjunction with increased transformer capacity by TransGrid at Sydney South is anticipated to be the most cost effective network solution.

In the longer term it is anticipated that TransGrid will need to establish a new 330/132kV substation in the Homebush/Chullora area. In conjunction with this work modification and augmentation of EnergyAustralia's system will be required. Possibilities that significant network expenditure associated with this project could be deferred through DM or contracting with large co-generators for network support will be investigated.

Central Coast Load Area

This region is rapidly growing and both the distribution and transmission systems will require a large amount of augmentation to provide and maintain the integrity of the electricity supply system.

The Central Coast is normally supplied from TransGrid's supply points at Munmorah, Sydney East, Vales Point and Tuggerah. TransGrid's Tuggerah substation has only a single transformer and is supplied by a single 330kV line. Munmorah 132kV supply point also has a single transformer. EnergyAustralia's 132kV system interconnects the above TransGrid supply points, providing capacity when critical 330kV transformers or feeders are out of service. EnergyAustralia's 132kV network provides local supply and operates in parallel with the TransGrid 330kV network, carrying power from the Central Coast generators to the Central Coast and Northern suburbs of Sydney.

Anticipated Projects

2007-08 – Uprating of Berkeley Vale zone to 132/11kV operation and installation of a 132kV feeder between Tuggerah and Berkeley Vale - $15m

EnergyAustralia anticipates that a distribution system augmentation will be required in 2006-07 involving uprating of Berkeley Vale zone to 132kV supply. The 132kV connection arrangements for this substation are presently under review. This substation may form a new connection point between EnergyAustralia's distribution and transmission networks depending on the 132kV connection arrangements selected.

One connection option being considered would involve looping feeder 958 into Berkeley Vale substation and installing a new 132kV feeder between TransGrid's Tuggerah substation and Berkeley Vale. If this connection arrangement is adopted the project will be a transmission project.

The constraints requiring this work are:

- loading on Berkeley Vale zone which is forecast to reach unacceptable levels in 2007;
- loading on the 33kV feeders supplying Berkeley Vale zone which is anticipated to reach the thermal capacity of the feeders by 2007;
- voltages on the 33kV system at Berkeley Vale are approaching their lower limits during first contingency feeder outages; and
- loading on Ourimbah substation, which supplies Berkeley Vale is approaching the substation rating.

Uprating of Berkeley Vale to 132kV operation will provide additional local capacity and will alleviate loading issues at Ourimbah sub-transmission substation enabling supply to be maintained to the Berkeley Vale during first contingency outages in accordance with Schedule 5.1 of the NEC. The proposed work is thus a reliability project.

At this stage this project has been included in the IPART distribution submission rather than the ACCC submission as it may be a distribution project.

Lower Hunter Load Area

Significant load growth continues for the Lower Hunter particularly in developing fringe areas to the West of Newcastle as well as around Lake Macquarie, Maitland and Port Stephens. Changing economic focus for industrial and commercial activity in the region is also contributing to changing spatial loading trends requiring associated supply network re-arrangements.

TransGrid is proceeding with advancement of the provision of a single 330/132kV transformer at Waratah West by March 2004. This is required to provide increased capacity for Tomago Aluminium Smelter and allow for transformer maintenance outages at Newcastle 330/132kV Substation. The project will have little initial impact on required configuration of the EnergyAustralia Network. However, in the longer term, transmission development requirements are under ongoing joint planning consideration with TransGrid.

The existing Lower Hunter 132kV Network is fully utilised and very high levels of augmentation activity will occur over a large proportion of the network during the next five to ten years. The associated planned projects that will impact on the configuration and loading on the transmission network in the Lower Hunter are listed below.

Committed Projects

2003-2005 – Supplying increasing demand in Tarro-East Maitland - Beresfield 132/33kV sub-transmission substation - $20m[11]

A new 132/33kV substation is being developed at Beresfield, which is located in the developing areas along the main transport corridor between Newcastle and Maitland. The substation will be supplied from existing 132kV feeders 9NA and 96F. It will have an initial 120MVA firm capacity and provide 33kV supply to Tarro, East Maitland, Wallalong, Martin’s Creek, Gresford and the future Thornton zone substation. Beresfield is required to provide necessary load relief for Kurri and Tomago sub-transmission substations as well as address limitations on the 33kV network supplying the East Maitland and Tarro areas.

Anticipated Projects

2006-08 Beresfield 132kV Feeder Augmentation – $5m

A new 132kV feeder connection is proposed from Newcastle 330/132kV Substation to the future Beresfield sub-transmission substation to provide increased capacity for load growth and to support Taree load after TransGrid’s conversion of Waratah West to 330kV. Co-locating this feeder with existing feeder 9NA may be possible. Scope may also exist to coordinate construction work with future refurbishment work on 9NA. The new feeder may also be arranged to provide a future “looped through” connection to a proposed 132/11kV substation at West Wallsend for development around 2010.

2005-06 Tomago 132kV Feeder Augmentation – $4m

A new 132kV feeder connection is proposed between Waratah West and Tomago sub-transmission substation. The feeder may be configured to provide scope to form a looped through or teed connection to the proposed Kooragang 132/33kV substation. This project will provide increased capacity for supporting future load at Tomago and Port Stephens and also provide a second circuit after full conversion of Waratah West to a 330/132kV substation. It is proposed that the existing supply to Taree from Tomago will be via a direct connection to the future Beresfield 132kV bus.

[11] Substantial expenditure is expected to occur prior to the start of the regulatory period.

2008-10 West Wallsend 132/11kV Zone Substation – $8.3m[12]

This is a proposed project to service growing development around Edgeworth, West Wallsend, Estelville and Holmesville and involves development of a 132/11kV zone substation in the Cameron Park industrial area near West Wallsend. It is proposed that the substation be supplied by 132kV feeder 9NA or a new feeder development for Beresfield.

4. Asset Management

Capital/Operating Cost Trade-off

EnergyAustralia's transmission asset base has a replacement value of approximately $1billion. Included are substations, transformers, towers, overhead lines, cables, and other equipment. All these assets require some level of maintenance throughout their life and the direct maintenance expenditure on these assets in 2002/03 was $11 million. The level of maintenance of an asset varies with the condition and age of the asset. Over the next regulatory period transmission maintenance expenditure is expected to increase from $15.6m in 2004/05 to $17.2m in 2008/09.

Our projected level of transmission replacement capital expenditure over the next regulatory period is $60 million, a moderate increase over the last regulatory period. The replacement of transmission assets in a heavily urbanised region such as Sydney is a difficult exercise. Difficulties arise because of the location of the assets but also because of the critical nature of the assets from a network perspective. Replacement of transmission assets will inevitably need to be undertaken in conjunction with TransGrid and will require the distribution system to be able to cater for changes to the configuration of the transmission network during construction. The CBD Augmentation project has occupied a great deal of TransGrid's resources and as a result, they have a backlog of augmentation and replacement projects elsewhere in their network. Similarly, EnergyAustralia has a backlog of replacement projects, particularly within the distribution system, which are needed before transmission replacement projects can be undertaken. As a result, the level of transmission capital expenditure in the current regulatory period is relatively moderate but is expected to increase significantly in the following regulatory period (ie 2004-09).

The Operating and Maintenance Model

There is an explicit relationship between capital investment and maintenance expenditures. With the assistance of SKM, this relationship has been modelled over the lives of major asset categories. The key parameters of the model are the average and the initial expected operating and maintenance expenditure by each major asset category, and industry benchmark maintenance costs over the life of an asset, which are defined relative to the replacement value of that asset category.

SKM modelled the following classes of transmission assets:

1. Sub-transmission substation circuit breakers
2. Zone substation circuit breakers
3. Sub-transmission substation transformers and tap changers
4. Zone substation transformers and tap changers
5. Sub-transmission and zone substation protection and control

For each of these categories an average O&M spend as a percentage of the Replacement Cost of the assets was calculated as well as an initial expected O&M cost. The expenditure in each category is due to planned, corrective, and emergency (breakdown) maintenance. The initial expected O&M expenditure was taken to be planned maintenance cost only and as emergency (storm) maintenance is not affected by refurbishment investments, it was excluded from all calculations.

[12] Substantial expenditure is expected to occur after the regulatory period.

Major projects and programs of capital expenditure have been evaluated with regard to the expected Operating Expenditure/Savings. For the programs an average asset age was assumed and used in the model as the age at which assets within that class would be replaced. For major projects, an average age was determined based on specific age information available for the projects.

- Total expected O&M expenditure on new assets: This is the cost of O&M on the new assets added through the major projects and programs. The costs for each asset category are ascribed the initial O&M cost.
- Total expected O&M savings on refurbished/replaced assets are obtained by replacing an old asset with a new asset. The saving represents the difference in O&M costs between a point high on the curve (an older asset) compared to O&M costs (a new asset).

The total transmission system capital expenditure projected for the next regulatory period is $116 million. The expected net operating and maintenance expenditure based on these major projects and programs are summarised in Table 6 in the following section.

5. The Transmission Operating Program

The two key drivers of the operating program are asset age and offsetting savings as a result of the transition from a time-based to a condition based maintenance.

It should be noted that the impact of condition based maintenance has less of an impact on transmission assets than on distribution assets because of the failure characteristics of these assets. This relationship is explained in some detail in Appendices C and D of SKM's Review of EnergyAustralia's Operating Expenditures which is included as Attachment 5 of this submission.

In the transmission Determination, EnergyAustralia has assumed the implementation of a new asset and works management system to ensure that available efficiencies are achieved in the delivery of the operating program.

Continuing pressures that have emerging during the current determination period are increases in insurance and rates and compliance with obligations arising from new OH&S and environmental regulations. These factors will continue to influence operating expenditure required for the transmission Determination in 2004-09.

Table 8 sets out our proposal for the total operating expenditure for the transmission business over the course of the regulatory period 2004-09.

Table 8 - Proposed Total Operating and Maintenance (O&M) Expenditure $'Million (Real – $2003/04)

	Financial Years				
	2004/05	2005/06	2006/07	2007/08	2008/09
Forecast Total O&M expenditure	**24,370**	**25,751**	**26,559**	**27,143**	**27,729**
Maintenance Expenditure	**15,599**	**16,693**	**17,031**	**17,154**	**17,221**
Transmission Subs	6,684	7,177	7,356	7,643	7,504
Zone Subs	2,101	2,255	2,310	1,941	2,354
O/H Transmission Lines	1,694	1,776	1,778	1,801	1,739
U/G Transmission Cables	5,120	5,484	5,587	5,769	5,624
Other	**8,771**	**9,059**	**9,528**	**9,989**	**10,508**

Characteristics of EnergyAustralia's Transmission Network

The age profile of the network is largely determined by the history of its development and population growth. As assets age, the cost to maintain those assets increases. In EnergyAustralia's case, the majority of the network was constructed during the high growth period of the 1960s and 1970s.

EnergyAustralia is currently implementing a condition-based maintenance regime. However, the relationship between the level of maintenance expenditure and age has been clearly established on the basis of industry benchmarks. This relationship for key transmission asset categories is discussed in more detail below.

It is important to note that the efficient replacement of both transmission and distribution assets will require an integrated approach for both replacement and augmentation. Within the next regulatory period, one major project (Green Square) will see the replacement of an existing distribution asset with a transmission solution. In the following period it is anticipated that the most efficient way of replacing and augmenting the transmission and distribution system will involve an expansion of the transmission network.

The increase in maintenance costs is primarily the result of the costs associated with an old asset base combined with relatively low levels of replacement capital expenditure during the last regulatory period. This low level of replacement of capital replacement expenditure has been discussed above and arises from the complexities associated with transmission assets.

Table 9 - Projected ageing of asset classes with base case capital expenditure

Weighted Average Age at year start (yrs)			
Asset Class	**1999**	**2004**	**2009**
Underground Transmission Circuits	36.2	40.0	42.6
Overhead Transmission Lines	33.0	37.3	41.7
Zone substations	31.55	33.74	36.31

Maintenance cost estimates

Average unit costs of key maintenance activities for the last three years were used to forecast the cost of maintenance activities by major asset category. The actual expenditure between 1999/00 and 2001/02 and the weighted average age of the assets in this year were used to locate EnergyAustralia's current position on benchmark maintenance curves and to project the impact of age on future maintenance expenditure requirements.

Despite our proposed replacement program, the network is still expected to age nearly two years (check for Transmission) over the next regulatory period. The net addition of new assets is an additional secondary driver of maintenance expenditure.

The three key transmission categories with the most significant increases are detailed below.

Transmission Substations

Maintenance costs for transmission substations are forecast to increase from $6.7 million to $7.5 million over the next regulatory period. This increase is in line with the increase in the average age of these assets, which is expected to increase from 34 years at the start of the next regulatory period to 36.3 years.

The increase in maintenance costs in this asset class is the result of an expected increase in corrective maintenance of existing assets combined with a small contribution from new assets. Over the next regulatory period, $34 million of capital expenditure is planned in this asset category with an even mix of replacement and new expenditure.

Zone Substations

Maintenance costs for zone substations covered by the regulatory definition of transmission are forecast to increase from $2.1 million to $2.4 million over the next regulatory period. This increase is in line with the increase in the average age of these assets, which is expected to increase from 32 years at the start of the next regulatory period to 30.1 years.

The increase in maintenance costs in this asset class is the result of as an expected increase in corrective maintenance associated of existing assets combined with a small contribution from new assets. Over the next regulatory period, $4.4 million of capital expenditure is planned in this asset category with an even mix of replacement and new expenditure.

Underground Transmission

Maintenance costs for underground transmission during the next regulatory period is forecast to increase from $5.1m to $5.6m. This increase is driven by an expected increase in corrective maintenance. The general increase is in line with the increase in the average age of these assets, which is expected to increase from 40 years at the start of the next regulatory period to 42.6 years by 2009. As discussed above, where feasible, assets in this category requiring replacement will be replaced. Capital expenditure on underground transmission assets is projected at $13m over the next regulatory period.

Overhead Transmission

Maintenance costs during the next regulatory period are forecast to remain relatively stable at $1.69m to $1.74m over the next regulatory period. This increase is driven by an expected increase in corrective maintenance of these assets. This increase is in line with the increase in the average age of these assets, which is expected to increase from 37.5 years at the start of the next regulatory period to 41.5 years.

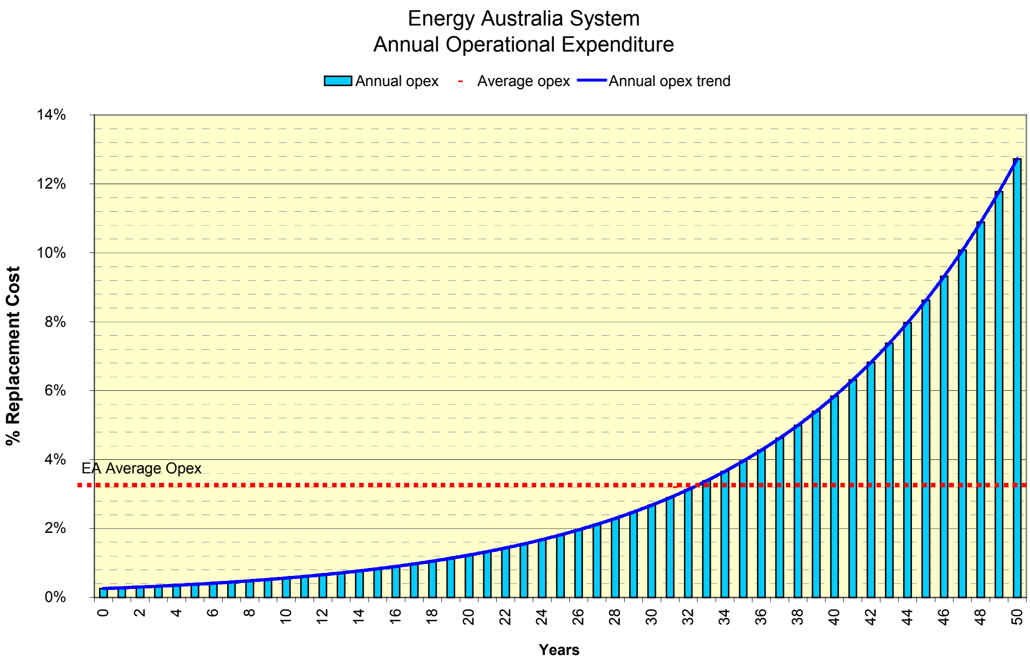
Capital expenditure on this class of assets is projected to be $4m over the next regulatory period.

In addition to the impact of age on maintenance costs, the transition from time-based to condition-based maintenance has highlighted the need for an ongoing increased level of planned maintenance expenditure. The benefits of this approach to maintenance include:

- increased focus on the overall life-cycle costs of assets and the costs of maintaining an asset over its life; and
- a significant and sustained reduction in the level of reactive, breakdown maintenance in the longer term. Initially, however, the introduction of the new maintenance regime is not expected to result in an immediate reduction in the levels of breakdown and reactive maintenance.

This major review of the overall maintenance framework has been undertaken during the 1999 Determination. It has resulted in the establishment of a revised, condition-based maintenance framework and strategy. This revised methodology has been developed with the assistance of best practice firms within transport and military sectors familiar with the use of techniques such as FMECA (Failure Modes Effects Critically Analysis) and Reliability Centred Maintenance (RCM). These techniques undertake a detailed assessment of the inherent failure characteristics of every asset type and require the determination of an appropriate maintenance and or replacement program for each asset. This process trades off the costs of maintenance activities against the risks and consequences of failure. This work has taken nearly two years to develop and EnergyAustralia in the process of implementing this framework.

Figure 12 - EnergyAustralia System Annual Operational Expenditure



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 and are inherent in the design of an asset. As a result, it is possible to design maintenance activities around managing these failure characteristics. The advantage of this approach is that maintenance expenditure is focused primarily on programmed maintenance that achieves an appropriate balance between planned and reactive maintenance on an overall risk profile, thereby maintaining the reliability of the overall network.

Full implementation of the condition based maintenance regime will ensure that maintenance costs are at world's best practice. However, until significant experience is gained with the new regime there must be some uncertainty relating to the required long-term level of maintenance costs.

As previously indicated, EnergyAustralia's operating cost submission is for a moderate increase on the level of costs allowed in the 1999 Determination. These increases are due to increased levels of activity, particularly in the area of maintenance and associated costs, but also are due to the impact of new regulations and business functions.

The impact of cost increases in the areas of insurance, tax, market and regulatory compliance, and vegetation management that have occurred in the current period are expected to continue into the next regulatory period. These costs are discussed in more detail below.

Other Operating Costs

Insurance, Taxes and Rates

When EnergyAustralia made its submission prior to the last Determination, it did not foresee or make allowances for a 'hardening' of the insurance market towards the end of the regulatory period. The severity with which the market has hardened - as evidenced by substantial increases in premiums over a number of classes of insurance - has had a significant impact on operating costs.

A variety of factors have contributed to increased insurance costs, most notably, the events of September 11, 2001 and the collapse of HIH Insurance. The reaction of the insurance market to these events is briefly described below:

1. The collapse of HIH Insurance. The liquidation of the HIH Group of companies has served to diminish the supply capacity of the insurance market. As a consequence of the removal of this industry price setter, remaining participants have been presented with the opportunity of increasing premiums, particularly in classes of the market that were already considered unprofitable.
2. The events of September 11. The immediate response by insurers, was not unexpected. The sudden erosion of a considerable volume of capital triggered a reassessment of risk exposure and profitability of current underwriting. A more disciplined approach to underwriting was seen as a way of restoring investor confidence. This has taken the form of increases in premiums and policy excess, and limits and exclusions on policy cover.

EnergyAustralia, like many organisations with insurance coverage, has had to reassess its risk profile and insurance position in light of the insurance industry 'shake up'. Under the higher excess now in place, EnergyAustralia's claims management unit administers an increased number of claims. Tightening contracts where further limits and exclusions are imposed have required EnergyAustralia to reassess exposure to risk and seek alternatives to reduce such risk. Reprioritising capital programs with a greater emphasis on pro-actively mitigating risk has been part of EnergyAustralia's response to tighter insurance policies developed in a consolidated market where fewer, larger players exercise greater discretionary power when negotiating contracts.

As a result of the two major events listed above, together with an insurance market that had already commenced to harden, EnergyAustralia will be faced with marked increases in insurance premiums. Additionally, consideration of rising costs associated with self-managing claims under a higher deductible has led to an increase in self-insurance costs projected for 2003/04.

Estimates provided by EnergyAustralia's insurance broker, AON, suggest that, for the 2003/04 insurance year, public and products liability (including professional indemnity) will increase by 100 per cent and directors and officers insurance will rise by 15 per cent. Based on these estimates, it is expected that EnergyAustralia's total insurance premiums alone will increase by $1.9m in 2003/04.

In line with all other industry participants, EnergyAustralia has suffered increase costs to externally insure those risks that can be efficiently priced and managed. Those risks include:

- Bushfire (Losses > $10 million)
- General Public and Products (including stop loss workers compensation & asbestos removal liability)
- Directors and Officers
- Professional Indemnity
- Property Insurance (Substations > $10 million, buildings, depots, contents etc)
- Contract Works Insurance
- Motor Vehicle Insurance
- Fidelity, Travel, Personal accident Federal Government Terrorism Insurance Scheme & Interstate Workers Compensation Insurance

Other risks which are either not economic to externally insure or are best managed internally through prudent asset management strategies. (The treatment of internally borne risks is discussed elsewhere in this submission.) Losses associated with damage to assets as a result of storms or bushfire less than $10 million is self-insured. Energy Australia's current accounting policy is that where an asset is damaged, the cost of repairing the asset to the same standard is treated as an operating expense. This treatment is based on the nature of the work done and whether the service potential or useful life of the asset is changed.

Occupational Health & Safety Regulation

With the introduction of the new OH&S Act 2000 and the associated OH&S Regulation 2001 certain new obligations have arisen that EnergyAustralia has had to adhere to and must make allowance for in its operating expenditure. The following new obligations have arisen since 1999 that were not included in the cost forecasts made in 1998. These are detailed in Table 10.

Table 10 - New obligation arisen from NSW OH&S Regulation 2001

Area	Activity Description
Asbestos management	Although the requirements for managing asbestos are not new, the introduction of OH&S Regulation 2001 has brought with it a heightened awareness of EnergyAustralia's obligation. Included in the cost of asbestos management is the requirement to train all relevant staff in asbestos awareness, ensuring they are familiar with, and follow, safe techniques in handling asbestos. EnergyAustralia also provides staff with asbestos kits where there is the risk of asbestos dust exposure in their work environment.
Confined spaces	The cost of working in confined spaces has increased, as under the new OH&S Regulation, EnergyAustralia must provide its own on-site rescue capability. In the past, at least in the CBD, EnergyAustralia has relied on the NSW Fire Brigade arriving at the work site quickly to effect a rescue. However, WorkCover has insisted that this rescue capability be internally resourced.
Fall arrest	OH&S Regulation 2001 requires that, where the possibility of a fall of more that two metres can occur, fall arrest devices are to be employed. The type of work that EnergyAustralia performs, especially in underground pits and city substations, means that situations where such falls can take place are common. Consequently, adhering to this new requirement is particularly onerous. In addition, training for setting up and using the fall arrest equipment is necessary.
Safe work method statements (SWMS)	Within the new OH&S Regulation 2001 is the requirement to develop a series of SWMS's, a requirement specifically for the High Risk Construction Industry to which EnergyAustralia subscribes. Developing SWMS has been a mammoth undertaking by EnergyAustralia, particularly as EnergyAustralia is involved in the provision of a wide range of electrical-related services, each service requiring its own SWMS.
System restrictions	With an emphasis on hazard identification and risk mitigation under OH&S Regulation 2001, EnergyAustralia has further endeavoured to avoid work near live equipment. As a result, more time and effort is directed towards the organisation of outages and performing services outside normal working hours.

The new legislation also requires on-going documentation of risk management processes covering the design, acquisition, construction, operation and retirement of network assets that will add to operational costs.

The Ministry of Energy & Utilities has also foreshadowed the possible withdrawal or significant reduction in scope of the current exemption EnergyAustralia has, for work performed under its Network Management Plan, to Clause 207 of the OH&S Regulation 2001, relating to live work. The additional costs of compliance with a change to this exemption cannot be easily quantified until the changes are determined. Accordingly, if this matter cannot be resolved before the finalisation of the Determination, EnergyAustralia is seeking a mechanism in the Determination to allow the business to pass-through any material increased costs where regulatory changes occur after the Determination is made.

Environmental obligations

Environmental obligations are the most rapidly changing obligations that EnergyAustralia faces. New information regularly becomes available regarding the effect that pre-existing technologies and approaches have on the environment in which we live. EnergyAustralia is required to keep pace with the recommendations and regulations that result from the new research.

Since 1998, several new pieces of legislation have come into force. In addition, many of the existing pieces of legislation have been modified and extended with new regulations, adding additional costs.

In relation to the additional operational costs borne by EnergyAustralia to date, the Contaminated Land Management Act, the Pesticides Act and the Protection of the Environment Operations Act are relevant. The Native Vegetation Conservation Act relates predominantly to capital works and the costs of compliance have been capitalised.

The total costs borne by EnergyAustralia in relation to the Pesticides Act by the end of the regulatory period will be approximately $4 million based on the current regulations. However, additional regulations are still being developed. With regard to the Protection of the Environment Operations Act, EnergyAustralia has incurred annual costs of $5 million per annum since 1999 resulting in a total of $25 million by 30 June 2004. Regarding the Contaminated Land Management Act, EnergyAustralia has incurred annual costs of $2 million per annum since 1999, resulting in a total of $6 million by 30 June 2004. These costs are not the result of fines imposed by the EPA but are costs of compliance with the new regulation. Accordingly, we have included $6 million per annum in real terms for each of the years of the transmission Determination in our total O&M costs for 2004-1009.

Indirect operating costs

In the case of indirect/shared operating costs, it is necessary to allocate these costs between transmission and distribution services. These costs include some of the costs identified above such as insurance, rates and land tax, as well as shared IT, communications and control costs. These costs have been allocated on the basis of the transmission share of the replacement value of the total network asset base. On the basis of the most recent valuation of both asset bases (2002), this proportion is 12.4 per cent.

D INVESTMENT FRAMEWORK

A key feature of CPI-X incentive regulation is that a business's costs are assessed on a periodic basis and required revenue is determined *ex ante* for the upcoming regulatory period. This required revenue then determines how prices may change over the regulatory period. To the extent that actual costs differ from the costs projected in determining the revenue requirement, there is no *ex post* adjustment of prices. If the business is able to meet its service standards at a lower cost, it retains the additional profit implied. Conversely, if the business spends more than was projected, its profitability is reduced.

The rationale behind this approach is that it provides the regulated business with an incentive to improve its efficiency. It also provides a disincentive to undertake expenditure that is not prudent or efficient.

However, as capital intensive businesses, electricity transmission networks have a significant impact on the reliability and quality of supply experienced by end customers. From this perspective, it is evident that long-term consumer welfare would be enhanced by a regulatory regime that supports prudent investment in the transmission network. However, the CPI-X framework in its current form does not provide adequate incentives to support the required level of investment.

Recently, the Productivity Commission and the Council of Australian Governments (COAG) extensively reviewed regulation in a series of inquiries. While there have been recent developments relating to the appropriate governance arrangements for regulation in a national context[13], there is widespread agreement that establishing appropriate incentives for investment is desirable for all stakeholders.

EnergyAustralia has devoted considerable attention to identifying the incentives that are required in order to support an effective framework for investment:

- a regulatory period of sufficient length (i.e. five years) in order to provide an incentive to achieve efficiency gains which can then be shared between the business and its customers;
- certainty that prudent and efficient investments (both past and future) will be recognised in the regulatory asset base (RAB) and will receive a regulatory return on, and return of, capital;
- clarity as to what constitutes "prudent" investment on an *ex ante* basis (i.e. prior to the commitment of capital);
- the appropriate allocation of risks between the business and its customers and appropriate compensation for the risks borne by the business;
- flexibility within a regulatory period to provide investment certainty when confronted with significant and unanticipated changes;
- a commercial rate of return within each regulatory period; and
- a merit appeals mechanism to create an incentive for regulatory decision-making to be more accountable and transparent.

[13] See Ministerial Council on Energy – Communique released 1 August 2003.

1. Five year Regulatory period

The Code is prescriptive with respect to particular aspects of the regulation of transmission assets, including the minimum length of the regulatory period:

> *"… the ACCC is to set a revenue cap to apply to each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) for the regulatory control period which is to be a period of **not less than 5 years** [emphasis added]".*[14]

In line with the Code's minimum requirement, EnergyAustralia proposes a five year regulatory period as it provides a desirable mix of investment certainty, whilst limiting the period over which the impact of errors in decisions can accumulate.

In addition, a five year regulatory period provides an appropriate period over which the benefits of any out performance are shared between businesses and their customers. Under a CPI-X framework, businesses have the incentive to retain the benefits of any efficiency gains over the remainder of the regulatory period. Customers receive the vast majority of the benefits of any efficiency gains achieved by the regulated firm through lower prices over the medium and long term that may not otherwise have been achieved.

EnergyAustralia's network is concurrently regulated by IPART (the jurisdictional regulator for distribution pricing). The Code requirement for the length of the regulatory period for distribution pricing states that the jurisdictional regulator must adopt a regulatory control period of not less than three years[15]. IPART has recently stated its preference to adopt a regulatory control period of five years for the NSW DNSP's[16]. EnergyAustralia believes that it is practical to align the regulatory review periods for its regulated transmission and distribution assets to enhance consistency in the treatment of network assets regardless of their regulatory classification.

2. Form of regulation

Being regulated by two regulators has added complexities as the two regulators apply different forms of regulation to the parts of the network that they regulate. Like all TNSP's regulated under the Code, EnergyAustralia's transmission assets are subject to revenue cap regulation. However, IPART has recently adopted a weighted average price cap (WAPC) approach to the form of economic regulation for the NSW DNSP's. EnergyAustralia was a key advocate of the move to a WAPC and applauds IPART in acknowledging the benefits of the WAPC over the pure revenue cap that IPART had previously supported.

EnergyAustralia has a strong preference for a WAPC to be applied consistently to its entire network business. This is based on the following[17]:

Pure Revenue Cap

- Provides the TNSP with guaranteed income, regardless of services provided;
- The TNSP has no incentive to encourage any use of the network that would result in higher costs, irrespective of whether the benefit to the consumer is greater than the cost to society of that use. This is clearly inefficient, as the business has a financial incentive to minimise the use of the service to the extent that it lowers costs – even if the marginal

[14] National Electricity Code, clause. 6.2.4(b).

[15] National Electricity Code, clause 6.10.5(c)

[16] See IPART Issues Paper (DP58) "*Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004*", Page 36.

[17] Adapted from previous EnergyAustralia submissions during the leadup to the IPART's July 2002 "Notice under clause 6.10.3 of the National Electricity Code - Economic Regulatory Arrangements". Also adapted from the September 2001 paper from NERA paper titled "*Efficiency Properties of the Form of Price Control – A report for Integral Energy, EnergyAustralia and Country Energy*" which formed part of our submissions.

benefit to customers is greater than the marginal cost to the business of providing the service;

- In the case of a revenue cap, marginal revenues are set by the regulator (in this case to zero) and are completely independent of prices. As a result, the best this form of regulation can hope for is indifference on the part of the business with regards to its prices. However, if the marginal revenue is set above (or below) marginal cost, then this creates an automatic incentive for the business to price below (above) marginal cost;

- Therefore, at best, the revenue cap provides a neutral incentive for efficient pricing and, at worst, an incentive to price inefficiently. This creates strong incentives for inefficiently high prices;

- The revenue cap provides no mechanism to manage forecast volume risk; and

- The revenue cap requires the use of an adjustment mechanism to account for any differences between actual and forecast revenues. This can not only be complex to administer but can also result in significant year-on-year price shocks as the account balance is resolved.

Weighted Average Price Cap (WAPC)

- A key difference between a WAPC and a revenue cap is that with a WAPC the marginal revenue received for each additional unit varies according to the marginal price charged for that unit, rather than being set to zero (as set by the regulator) for the revenue cap;

- If marginal prices equal marginal costs, then the business has effectively hedged its output. That is, output prices for expected levels and changes in costs are matched by changes in revenues. Importantly, the incentive to match marginal prices to marginal costs is, by definition, an incentive to price efficiently. This incentive exists with the WAPC, but clearly does not with the revenue cap.

- The single most important way that a network business can manage the demand for network capacity is through efficient (ie., marginal cost) pricing. This gives customers the appropriate incentive to:

    - Reduce total demand for network capacity
    - Shift demand for network capacity to off peak periods; or
    - Change the nature of demand for service quality and type (ie., move to interruptible tariffs)

- It gives the business an incentive to reflect all of the marginal cost drivers in marginal prices and the flexibility to adapt them over time as is appropriate;

- It enables the management of volume risk;

- It provides price stability to customers; and

- It is administratively easy to administer.

EnergyAustralia recognises that the ACCC must apply a revenue cap at the 2004 Determination unless the Code is changed or a derogation were forthcoming, neither of which we believe is possible in the time available. However, we believe that consideration of forms of economic regulation other than a revenue cap should be undertaken during any review by the ACCC of its regulatory principles in order to allow public consultation on this important matter. EnergyAustralia will also work with other TNSP's in order to pursue this form of regulation for future transmission Determinations and other regulatory developments.

3. Recognition of prudent capital investment

The Regulatory Asset Base (RAB)

The Regulatory Asset Base (RAB) is arguably the most critical element of the regulatory framework. For electricity transmission networks, the asset base determines approximately 70 to 75 per cent of the required revenues, reflecting the capital intensity of the industry and the associated returns on and of that capital. One of the most significant risks borne by investors in the current CPI-X framework is the potential for prudent investment to be excluded from the RAB and therefore to not earn a return on, or return of, the original investment.

Code Requirements

In calculating the RAB, the National Electricity Code (the "Code") (cl 6.2.3(d)(3)) provides some guidance as the ACCC was required to have regard to COAG principles that state that deprival value is the preferred approach to valuing network assets for initial valuations. However, in a regulatory context deprival value is problematic given its implicit circularity (ie., where the value of the asset is equal to the revenue it generates). Therefore, a common approach adopted by regulators has been to interpret the deprival value methodology as an optimised depreciated replacement cost (ODRC) valuation.

This is an appropriate interpretation of the Code as ODRC is indeed one of the three elements of the ODV methodology representing the cost to replace the assets with assets of equivalent service potential should the firm be deprived of them. This could simply be assets of the same age and condition, or indeed a reconfigured series of assets to exploit new and cheaper technologies where appropriate.

The other two elements of the ODV methodology are inappropriate for regulatory purposes. The first element being the value in use, or the future revenue stream that the firm would be deprived of from losing the assets. This is clearly inappropriate and is where the circularity of the ODV approach arises. The final element of the ODV methodology is the scrap value of the assets, however this is generally dismissed from assessments where there is an ongoing concern assumption, and therefore is only appropriate where the firm is winding down operations.

The ACCC's publicly stated position regarding the appropriate methodology to value regulatory assets as expressed in its May 1999 draft *Statement of Principles for the Regulation of Transmission Revenues* ("DRP") is that:

> *" … the Commission considers that given the circularity that would be associated with any deprival value assessment, a depreciated optimised replacement cost (DORC) valuation should be adopted for any initial valuation*". [18]

EnergyAustralia believes that an ODRC valuation is indeed an appropriate basis for setting an initial regulatory asset valuation and as such should be used to establish the opening RAB for the 2004 Determination. Our reasons are as follows:

In 1999 EnergyAustralia's total network was valued on a basis consistent with the regime applied to DNSP's in NSW. Whilst this was appropriate for distribution purposes, it has created a systematic difference in the approach to valuing transmission assets within NSW, let alone the NEM, that EnergyAustralia seeks to resolve. Specific examples are discussed later in this Chapter.

In addition to aligning the basis of asset valuations for transmission networks in NSW, EnergyAustralia notes the Commission's own arguments supporting the adoption of ODRC as an appropriate asset valuation methodology:[19]

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[18] ACCC DRP, May 1999. Page xi.

[19] Adapted from the ACCC DRP, May 1999. Page 40.

- That ODRC replicates the price that would be charged by an efficient new entrant to an industry, and therefore is consistent with the price that would prevail for the long run industry equilibrium. Moreover, a symmetric pricing and incentive structure between a regulated and a competitive outcome has positive resource allocation attractions;

- Any value in excess of ODRC can be expected to subject the asset holder to bypass risk, whilst this has practical limitations the regulatory enforcement of this market discipline is none the less appropriate; and

- That the ODRC methodology measures the acquisition cost of the future service potential of the existing assets, and the maximum value the market would be willing to pay in order to acquire that service potential. This valuation takes into consideration the existing assets and all available alternatives, such as new and cheaper technologies, and therefore assumes an informed and efficient purchaser, ensuring efficiency in outcomes.

Notwithstanding, for regulatory periods subsequent to the 2004 Determination, EnergyAustralia supports the in-principle use of a "roll-forward" approach to determining the regulatory asset base. A roll-forward may significantly reduce the subjectivity associated with other forms of valuation and provide more certainty that prudent and efficient investment will earn a regulatory return over the lives of the assets. This support is contingent, however, on the regulator providing guidance on an *ex ante* basis as to what constitutes "prudent and efficient" investment and, in fact, how the roll-forward is to be undertaken.

EnergyAustralia believes that this approach is appropriate and would serve to minimise the regulatory risk associated with asset valuation methodologies relying on a high degree of regulatory discretion. Uncertainty regarding the regulatory recognition of prudent capital investment would only serve to increase the underlying cost of capital of the business, ultimately serving to increase the costs to customers and / or providing a disincentive to invest in required infrastructure.

However, before a roll-forward methodology could be supported, it is essential that the starting point needs to be based on an appropriate value of the assets to be regulated. EnergyAustralia submits that the 1999 ODRC valuation contained many anomalies that are of sufficient magnitude to be material. EnergyAustralia believes that it is necessary to address any errors or inaccuracies contained in the 1999 ODRC valuation so that they are not institutionalised and carried forward indefinitely in any roll-forward calculation.

Therefore, EnergyAustralia believes that it is necessary to adopt an ODRC valuation at the outset of the 2004 Determination. EnergyAustralia has engaged Sinclair Knight Merz ("SKM") to perform and ODRC valuation for EnergyAustralia's transmission assets as of 30 June 2004. This valuation is provided as Attachment 9.

The following section outlines some of the issues associated with the 1999 ODRC valuation that we believe warrant a new ODRC valuation to be undertaken for the 2004 Determination.

Errors in the 1999 ODRC valuation

Inconsistent valuation principles

The 2000 Determination on the revenue cap for EnergyAustralia's transmission assets concluded that the total regulatory asset value assessed by the Commission for the start of the period was $457.4 million[20]. However, EnergyAustralia submits there were significant problems with the 1999 valuation that make it an inappropriate starting point for a roll-forward for the 2004 Determination.

One of the major thrusts of the market reform stemming from CoAG was to establish a National Grid with uniform trading and pricing arrangements. Differing valuations of

[20] NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04 Decision, 25 January 2000. Page 136. It is noted in the Decision that after the Commission's draft decision was released, NECA sought on behalf of the NSW Government authorisation of a derogation which would give the Commission responsibility for determining the opening asset value to be applied to EnergyAustralia's parallel transmission assets (subject to the principles in the Code). The Commission granted interim authorisation to that derogation on 15 December 1999.

transmission network assets will lead to non-uniform pricing and so prevent the achievement of this objective.

EnergyAustralia's network assets were valued by the NSW Jurisdictional Regulator for distribution on a modified ODRC basis at the commencement of the last regulatory determination, along with those of other DNSP's. This valuation was carried out by the Worley's Consortium using principles designed for valuing distribution assets and which were different to those used for TransGrid's asset valuation.

Typically, due to the relatively small number of transmission assets and their relative cost, transmission assets are evaluated in more detail than distribution assets. For example, transmission line values take into account detailed adjustments for the terrain and number of angle structures. This is due to the recognition that the costs of a single angle structure can be as high as $500,000, up to 5 times that of a standard structure. For EnergyAustralia this is a material concern as the areas where EnergyAustralia has a high density of transmission assets is also an area that requires relatively high numbers of more expensive structures to negotiate large expanses of water and hilly terrain (ie Central Coast).

Overall, SKM has estimated the magnitude of these types of unit rate differences to undervalue EnergyAustralia's total regulatory asset base by more than 8 per cent[21]. In addition, an ODRC valuation for transmission assets typically involves more detailed considerations of asset optimisation. Thus, the approach applied to the valuation of EnergyAustralia's transmission assets in 1999 differs from that applied to TransGrid at the same time, thus resulting in inconsistency between the relative valuations of assets within NSW.

The assets of the NSW transmission businesses are incorporated into a single pricing model, in accordance with the Code requirements[22], and these differences in valuation appear as anomalies in NSW transmission prices. If national transmission pricing is implemented, these anomalies would extend throughout the NEM.

In order to rectify this situation, the basis of the SKM valuation is the same as that recently used for other transmission businesses and similar to that used by TransGrid in 1999[23].

The 2004 ODRC takes into account improvements in EnergyAustralia's record keeping systems made during the course of the current determination and has highlighted that the average age of EnergyAustralia transmission assets is less than the average age of all assets of the same class.

EnergyAustralia submits that this fresh ODRC valuation is more appropriate for its assets than a roll-forward, which would lock in errors in unit rates and institutionalise the inconsistencies in asset valuation between EnergyAustralia and other TNSP's.

Distorted asset age profile

As further support for an ODRC approach in 2004, EnergyAustralia, through the completion of its annual regulatory accounts, has become aware of the serious limitations of the 1999 valuation relating to the use of average ages for asset categories.

The current average ages for asset categories do not accurately portray the nature and condition of the underlying assets. This is due to the fact that aggregate ages for large asset categories used in 1999 were derived by weighting the ages of individual asset classes using their written down value. This calculation applies a higher weighting to younger assets and has the effect of distorting the underlying asset age profile.

This distortion is compounded when new assets are added to the large asset categories. This is an important factor for EnergyAustralia, which has an aging network, many parts of which are earmarked for replacement in the next decade.

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[21] This is equivalent to $55.4 million.

[22] This pricing mechanism is explained in the introduction to this submission.

[23] TransGrid's asset valuation was reviewed and adjusted for the ACCC by SKM.

EnergyAustralia has reviewed the remaining life assumptions of several classes of assets and wishes to adjust them to reflect more recent information. However, due to the lack of detailed information on asset ages included in the 1999 valuation, we do not possess the detailed information needed to modify a component within the larger asset classes, and consequently cannot adjust the regulatory lives attached to these assets.

EnergyAustralia believes there is risk that a roll-forward would lock in the use of remaining lives at a high level, and that EnergyAustralia will retire assets that have not been fully depreciated for regulatory purposes at the time the physical asset is replaced (ie regulatory "stranding" of the assets).

EnergyAustralia submits that the remaining lives must be reviewed, and be reviewed on a more detailed level. This is critical to ensure that the ACCC and EnergyAustralia have more accurate information on which to base their decisions.

An ODRC approach does not rely on comparison of information from one period to the next. It merely values the assets at a point in time on the basis of remaining asset lives. EnergyAustralia believes that an ODRC approach for the 2004 Determination would allow for a correction of such previous errors.

The ACCC's roll-forward methodology

As noted above, EnergyAustralia proposes that a new ODRC be applied to its opening transmission assets as at 1 July 2004. This is due not only to the errors and inconsistencies of the previous ODRC valuation, and the technical complexities that could be avoided by completing another ODRC, but also because of the uncertainty surrounding the ACCC's roll-forward approach.

EnergyAustralia notes that there is no one universally agreed approach to calculating a roll-forward, and in fact there are many variations in the manner in which one could be conducted. Moreover, the investment incentives and decisions of a TNSP are heavily dependent upon the approach taken by the Commission and EnergyAustralia believes it has significant value at risk depending on how the ACCC may undertake a roll-forward. Given that investment incentives are prospective by their nature, it is critical that they are understood ex ante to enable them to be appropriately considered prior to investment decisions being taken.

As a matter of principle, EnergyAustralia does not believe that its past investment decisions should be measured by criteria that were not in place when the investments were made.

Before EnergyAustralia could consider supporting a roll-forward approach, the ACCC would need to clearly articulate its position in detail on a number of issues including:

- **Asset methodology** - What is the starting asset valuation methodology and when is indexation applied? What is the index to be used, and what is its basis, timing and derivation?
- **Real versus nominal framework** - Is the framework a real or a nominal one and what impact does this choice have on the timing of indexation in the RAB?
- **Capital expenditure** - How is actual capital expenditure treated if it is above or below forecast? What tests are to be applied to actual capital expenditure to determine whether they should be added to the RAB for the subsequent period, if any , and when are the tests applied? Does the ACCC propose to include a return on and/or a return of capital associated with prudent capital expenditures in excess of allowed amounts?
- **Stranding risk** - How is the stranding of assets managed and what tools are available for the TNSP's to manage stranding risk under the roll-forward?
- **Capital contributions** - How are capital contributions and the associated income tax liabilities managed?
- **Return of capital** – Will the return of capital for the subsequent regulatory period be derived using a return of capital consistent with the determination or using "actual" (ie accounting) depreciation? What are the capital maintenance and pricing objectives supporting the preferred profile and methodology? Are remaining lives reviewed, and if

so how, when, and on what basis? How are changes to remaining lives managed? How is indexation managed in the depreciation profile?

- **<u>Capitalisation & holding costs</u>** - When are assets recognised in the RAB? If there is a delay in capitalisation, are the associated holding costs recognised? If so, how are the holding costs calculated?

- **<u>Easements</u>** - How are existing easements valued? How are new easements valued? What is the appropriate index to apply to easements?

Given the uncertainty surrounding the regulatory treatment of the above issues within the ACCC's roll-forward framework - which in aggregate represent significant value at risk for EnergyAustralia - and the errors and inaccuracies in the 1999 ODRC valuation, we have no other feasible alternative than to support the adoption of a new ODRC valuation for the 2004 regulatory period.

It has also been recognised by the ACCC that the application of ODRC requires judgement, therefore when the RAB is revalued it must be done according to clear guidelines. The DRP[24] indicates that such guidelines were to be developed by the Commission prior to 2002. However, in the absence of such guidelines available at time of preparation of this submission, the SKM valuation has been based on a methodology consistent with similar valuations for other TNSP's in Australia and New Zealand.

Transmission Assets to be Included in the 2004 Valuation

As noted previously, the definition of transmission assets used in this submission includes those classified as being part of a "transmission network" under the Code.

The Code defines transmission assets as follows:

> *"A network within any participating jurisdiction operating at nominal voltages of 220kV and above plus:*
>
> *(a) any part of a network operating at nominal voltages between 66kV and 220kV that operates in parallel to and provides support to the higher voltage transmission network;*
>
> *(b) any part of the network operating at nominal voltages between 66kV and 220kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network."*

EnergyAustralia does not own assets that operate above 220kV. However approximately 12 per cent of EnergyAustralia's network assets falls within part (a) of the Code's definition of parallel and supporting assets.

There is activity planned which will result in seven existing distribution circuits[25] and five existing distribution substations[26] changing, for operational reasons, from the classification under the Code definition of distribution to transmission in the current regulatory period. Furthermore, in the 2004-2009 regulatory period, a further three distribution circuits are planned to become transmission assets[27] and one existing transmission circuit[28] will be re-categorised as distribution in the same period.

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[24] Section 4.2

[25] Distribution circuits being re-categorised as transmission pre 1 July 2004: Ourimbah to Vales Point (957); Ourimbah to Tuggerah (95C); Gosford to Tuggerah (958); West Gosford to Gosford (956); West Gosford to Ourimbah (951); Somersby to Gosford (95E); Mt Colah to Somersby (95Z).

[26] Distribution substations being re-categorised as transmission pre 1 July 2004: Ourimbah; Gosford; Somersby; West Gosford; Mt Colah.

[27] Distribution circuits being re-categorised as transmission 2004 - 2009: Campbell St to Beaconsfield (9SA); Chullora to Potts Hill (240 and 241).

[28] Transmission circuit being re-categorised as distribution 2004 - 2009: Rozelle to Mason Park (900).

The reclassification of assets between distribution and transmission within a regulatory period has the potential to cause significant administrative complexities, as the economic regulation of these assets shift from one jurisdictional regulator to the other. This would have the effect of using different valuation rules and with the possibility that a given asset, when considered to be a distribution asset, may have a different value than when considered as a transmission asset.

As an alternative to EnergyAustralia's original proposal to re-define its transmission boundary (which was not approved by the ACCC), it is proposed that no *ex post* changes should be made to the asset base during the currency of the 2004 determination period. All movements planned up to the end of the current regulatory period (30 June 2004) should be applied to the regulatory asset base when determining the opening base for subsequent (ie. 2004) Determination. Attachment 2 sets out a full description of the assets that either have changed, or are expected to change, from the definition of transmission that was in place at the time of the 2000 Determination.

Furthermore, in order to simplify the complex regulatory definitional issue, EnergyAustralia has proposed that no adjustments be made for forecast movements of assets into or out of the transmission asset definition (as applied by the ACCC) after 2004 until the commencement of the subsequent regulatory period (ie., 2009). We believe it to be an unwieldy process to adjust, on an annual or more frequent basis, two regulatory reviews (IPART's Distribution Determination and the ACCC's Transmission Determination) based on the operating configuration of specific network assets. Given that the assets would continue to be regulated by a Jurisdictional Regulator, we do not believe that this would result in any "double counting" or other ring fencing concerns and provides a practical solution to a complex issue.

We acknowledge and commend the ACCC on endorsing the above approach as stated in a letter to EnergyAustralia on 29 August 2003:

> *"The Commission also endorses your suggested approach to assets which will change classification between distribution and transmission during the next regulatory period ie assets that are classified as being distribution or transmission as at 30 June 2004 continue that classification over the 2004-2009 regulatory period. The Commission feels this is the most practical approach and is consistent with the Commission's objective to permanently move the regulation of EnergyAustralia's entire asset base to IPART."*

It is further proposed that the assets to which the performance measurement regime applies (see Chapter F) should be treated in a consistent manner.

While EnergyAustralia submits that having all its non-parallel and non-supporting 132 kV and 66 kV assets deemed to be transmission assets would provide an administratively sound framework providing more regulatory certainty in the treatment of its assets, EnergyAustralia has applied to existing parallel and supporting definition for the purposes of this submission.[29]

4. ODRC valuation as at 30 June 2004

EnergyAustralia has engaged SKM to undertake an ODRC valuation of EnergyAustralia's transmission assets that are expected to be in service as at 30 June 2004. The SKM valuation is provided as Attachment 9.

Table 11 provides a breakdown of the components of the SKM valuation. The valuation necessarily includes asset movements between transmission and distribution categories due to network re-configuration and in accordance with the definition of "parallel and supporting" transmission network as discussed above.

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[29] EnergyAustralia was notified by the ACCC on 4 June 2003 that its request for a change to the definition of transmission for the purposes of the economic regulation of EnergyAustralia's transmission business had not been approved.

Table 11 - ODRC Valuation Summary

Asset Category	ODRC ($M) as of 30 June 2004
Substations	**234.0**
Transmission lines & cables, including cable tunnels	**209.6**
Land	**96.8**
Easements	**87.3**
SCADA & communications, emergency spares, non network assets	**61.4**
Work in progress -	**31.2**
Subtotal	**720.3**
Less capital contribution	**(18.2)**
TOTAL	**702.1**

EnergyAustralia notes that a considerable component of this valuation arises due to assets that have moved from distribution to transmission in line with the application of the Code definition (pricing and revenue impact discussed further in Chapter E).

5. Return of capital

Period for the return of capital

The return of the initial investment is critical in ensuring that all funds raised for capital investment are repaid and that new funds can be raised for the replacement assets. In calculating the rate at which the initial capital should be repaid, there are two essential factors to be considered: the technical and economic lives of the investment.

Because all assets do not have the same technical characteristics as the assets age, the assets' remaining technical lives need to be reassessed by asset class. In some cases, sound maintenance practices may materially extend the serviceable life of the asset beyond the standard life expectancy. In other cases adverse environmental or operating conditions may result in materially reduced serviceable lives.

Existing information demonstrates that, in several classes of assets, the current depreciation rates would result in some assets being replaced whilst still maintaining a significant residual undepreciated value. Alternatively, some assets with useful economic lives remaining could be replaced, as they no longer have any regulatory or revenue generating value. Clearly, neither case results in an appropriate matching of revenues and usage of service potential. In both cases, economic pricing signals to customers are skewed, and asset management becomes less efficient.

Accordingly, the depreciation rates of the affected assets need to be realigned to reflect the expected replacement dates. This requires adjusting the current rates of depreciation recovered for these assets. It must be emphasised that in order to maintain the investment incentives of the regulatory regime, these changes must be prospective only. Moreover, the asset values should not be retrospectively adjusted to account for the rates that would have been charged had the shorter lives been predicted when the investment was made.

Similarly, where specific assets can be identified to be at stranding risk in the future, TNSP's must be allowed to manage these risks by reviewing the depreciation rates applied to affected assets. This approach is not without precedent, and has in fact has been promoted by the ACCC in its current DRP.

Comparing the average age of each class of assets to the standard technical life for each asset class has been used as the initial basis for assessing the remaining life for each class of assets.

Economic life of new investment

EnergyAustralia recommends that unless additional information is available regarding the expected economic life of new investment, the return of capital allowance for new capital expenditure should be set using the standard asset life. This is the best engineering estimate of the technical life under normal operating conditions that can be expected of a particular asset type. Once in service, the actual conditions and particular characteristics of the specific asset can be observed. At this point the economic remaining life assessments should take precedence over the generic standard life assumption.

The SKM 2004 ODRC valuation provides an assessment of the standard asset life for each class of assets (see Attachment 9, Table 5-1), summarised as follows:

Table 12 - Asset Class Lives

Asset Class	Class Life	Average age for EnergyAustralia assets as of 30 June 2004
Substation switchbays	45 years	22.22
Substation buildings and establishment	60 years	21.30
Power transformers	50 years	27.05
Transmission lines – steel tower	60 years	36.86
Transmission lines – steel / concrete pole	55 years	11.12
Transmission lines – wood pole	45 years	35.33
Transmission cables	45 years	30.06
Cable tunnels	70 years	0.41

Return of capital allowance calculation

As discussed above EnergyAustralia has adopted an expected economic remaining life assumption for the Determination over which the current and new assets should be depreciated. For the purposes of determining an appropriate transmission revenue stream, EnergyAustralia has used the ACCC's "economic" depreciation calculation as contained in the ACCC's Post Tax Revenue Model (PTRM). We note, however, our concerns regarding the "back end loading" of the return of capital that occurs under this approach, and the associated pricing impacts in future regulatory periods. Should the ACCC consider moving away from its current ODRC valuation methodology, the issue of the appropriateness of economic depreciation needs to be revisited to ensure appropriateness and consistency within the framework.

EnergyAustralia submits a return of capital of $14.5 million in 2004/05 increasing to $20.5 million in 2008/09.[30]

6. The opening RAB for the 2009 Determination using a roll-forward

While EnergyAustralia has endorsed the use of an ODRC methodology for the 2004 Determination, it proposes that a "roll-forward" approach be adopted for the subsequent 2009 Determination. In order to ensure appropriate investment incentives are in place, EnergyAustralia submits that the steps for calculating the roll-forward at the next review be established on an *ex ante* basis. Therefore, EnergyAustralia proposes that the opening RAB for the 2009 Determination be established by a roll-forward methodology calculated on the basis that it:

- includes recognised assets as at 1 July 2004;

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[30] In nominal dollars.

- uses CPI to maintain the real value of assets annually;
- accounts for return of capital at the ACCC "allowed" level in the 2004 Determination [31];
- recognises actual capital expenditures over the 2004 Determination period;
- recognises actual disposals over the 2004 Determination period;
- recognises actual capital contributions, if any, as provided in the annual regulatory accounts;
- recognises the present value loss associated with tax paid on capital contributions, if any, as EnergyAustralia's capital investment in capital contributed assets; and
- recognises any assets that have moved into, or out of, the definition of transmission during the 2004 Determination.

Recognition of investment (capital expenditure) between 2004 and 2009

In order to provide positive incentives for new investment, investors must be sure that rates of return are sufficient to compensate for the risks inherent in the business. EnergyAustralia recognises that regulators may be unable or unwilling to bind the decisions of a future regulator. However, this does not relieve the economic regulator from developing a framework in which the regulator and investors alike can rely on the basic policies governing the treatment of capital investment over time, and the framework for adjusting those policies over time.

EnergyAustralia notes that the ACCC has indicated that the assessment of efficiency and effectiveness is to be considered in the calculation of the revenue cap. As discussed earlier in Chapter C – Asset Management, EnergyAustralia has undertaken an extensive review of its investment criteria. This was done to ensure our investment decisions are not only prudent under current industry practice, but also that the process is an improvement on industry practice and places EnergyAustralia at the forefront of investment management within the industry.

The process includes a series of technical and economic assessments as well as an assessment of alternative non-network solutions and the impact that all options would have on customer outcomes. EnergyAustralia believes that this approach will provide a high level of confidence that all future investments meet or exceed the requisite level of prudence and efficiency adopted by the ACCC. Therefore, in the absence of any guidelines on prudence and efficiency promulgated by the ACCC, EnergyAustralia submits that where capital projects can be shown to have been subject to the new processes, they should be recognised as prudent.

In addition to addressing prudence on the appropriateness of undertaking a specified project, EnergyAustralia's investment processes place specific attention on the efficiency of the costs of the specified project before funds are committed. This includes the identification of non-network solutions and Demand Management options. EnergyAustralia has adopted several efficiency initiatives in its capital program including the use of standardised equipment and configurations to take advantage of economies of scale. We submit that our assessments of non-network solutions and cost saving initiatives ensure that forecast costs for the identified capital projects are efficient.

However, we accept that it is appropriate for the ACCC to require an *ex post* assessment of the efficiency of EnergyAustralia's capital programs. However, given the time frames involved in undertaking capital works from design phase to construction and then commissioning, the costs are determined long before physical work commences and the ACCC's review processes need to take this into account

[31] As there has been no adjustment made to the allowed revenues to account for differences between actual and allowed capital expenditures, it would not be appropriate to use an "unfunded" depreciation calculation for the purpose of rolling forward the RAB.

We submit that it is appropriate for the ACCC to rely on EnergyAustralia's processes, subject to examination of appropriate processes being reviewed.

In summary, EnergyAustralia proposes that the ACCC adopt an approach that provides certainty to TNSP's regarding how the *ex-post* assessments of both efficiency and effectiveness will be conducted *prior* to the commencement of the regulatory period and prior to the commitment of capital.

EnergyAustralia submits that upon a satisfactory review of its governance procedures, the ACCC should rely on those procedures for ensuring efficient outcomes with appropriate *ex post* testing of outcomes.

Indexation of the regulatory asset base under a roll-forward framework

EnergyAustralia agrees that the regulatory asset base must be indexed annually to maintain the value of investment over time. EnergyAustralia agrees that CPI is appropriate for the annual indexation of the opening RAB. However, we note that CPI is not an appropriate inflator for projected capital and operating expenditures that may in fact increase at a level above CPI. In particular, the cost of civil works in or around the Sydney CBD, which is a major input into the costs of capital works, increases at a rate significantly above CPI. This disparity also has a major impact on the comparisons of works over time.

Recognition of Capital Contributions

Capital contributions are an important incentive mechanism to provide developers with economic signals of the costs of assets required to specifically service their connection to the network.

Whilst there are currently no projects planned in the current regulatory period where a customer will be contributing to the funding of transmission assets, it is possible that such projects may occur. In these instances it is clearly not appropriate for all customers to bear the costs of assets from which they cannot reasonably expect to receive a benefit. For this reason, the regulatory asset base calculation ensures that all capital contributed assets received by EnergyAustralia are eliminated from the opening RAB.[32]

However, the incentives for TNSP's to seek customer payments for assets dedicated to their own service is weakened due to the Australian Tax Office taxation arrangements where capital contributions received are taxable once received by the TNSP.

EnergyAustralia has sought relief from this obligation from the Australia Taxation Office, however, our proposal has not been adopted. EnergyAustralia therefore proposes a regulated solution whereby the NPV loss associated with the tax paid on capital contributed assets received by EnergyAustralia is considered as EnergyAustralia's "contribution" to the asset and is therefore included in the regulatory asset base and depreciated over the same period as the underlying physical asset.

This approach will ensure that the long-term business value incentives are re-aligned to provide balanced incentives for the TNSP's to appropriately seek capital contributions. EnergyAustralia notes that it is a well established practice for DNSP's in NSW to obtain capital contributions in accordance with any IPART determination on Capital Contributions. EnergyAustralia has set out a more detailed discussion of the implications of the income tax effects on capital contributions and the arguments for recognising the NPV loss caused by income tax paid on capital contributions in the RAB in Attachment 14. Included in this attachment is an extract of EnergyAustralia's arguments as raised with the ATO for excluding capital contributions from taxable income.

All figures provided in the calculation of the RAB are net of customer contributed assets. EnergyAustralia proposes that should any transmission capital contributed assets be received during the period, the associated NPV loss arising from tax paid should be considered as EnergyAustralia's contribution to the asset and should be included in the RAB and depreciated over the regulatory life of the underlying physical asset.

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[32] This practice applies equally for transmission and distribution regulatory regimes.

EnergyAustralia agrees that an appropriate ODRC valuation is indeed a reasonable starting point for regulation, and submits that this policy should be applied as the starting value for all assets that are entering the RAB.[33]

7. Risk Management

Pass-through Mechanism

EnergyAustralia believes that a flexible mechanism is required to address circumstances that may arise within a regulatory period that are significant in nature and not anticipated at the time of the Determination. An inflexible framework places an unsustainable level of risk on regulated businesses and exposes customers to significant price shocks at each subsequent review should unanticipated events not be addressed within a regulatory period. Regulated businesses face a limited up-side within the framework (revenue or price increases are constrained while decreases are not) and a seemingly unlimited downside (the risk of cost increases is significantly higher than the risk of cost decreases). Unlike unregulated businesses that can adjust their service/price mix when faced with changing levels of cost, regulated businesses face an obligation to supply regardless of changing costs or increased growth in customer numbers.

EnergyAustralia believes that in a world where regulated incomes are set for five years but where risk profiles can change overnight (ie. September 11, 2001) such limited review opportunities are impractical and place an unbearable amount of risk on the regulated business.

EnergyAustralia believes there is a need for a pass-through mechanism to address unanticipated cost increases that are outside of the business's ability to control. A number of one-off cost increases have directly impacted on the ability of EnergyAustralia to keep within the forecasts of the regulated operating expenditures. EnergyAustralia believes that the certainty and predicability surrounding the future operations of the regulatory regime would be increased and the inherent efficiency mechanisms within the framework will be preserved where explicit guidance is provided in advance on:

- The circumstances in which a cost pass through may be permitted during the regulatory period;
- The process which would be followed in respect of such applications; and
- The criteria by which such applications would be assessed.

There will always be some aspects of a business's costs which are difficult (or impossible) to predict. The question arises as to how best to reflect the costs of such uncertain events or circumstances in the regulatory regime. Several alternatives exist:

(a) Incorporate a projection of likely cost into the expenditure forecast (however 'rough' this forecast is). This would result in prices being higher than they would otherwise be, if the event did not occur;

(b) Not include estimates of uncertain events in the expenditure forecast but compensate the business for the increased risk it faces through a higher WACC. This would again result in prices being higher than they otherwise might be;

(c) Make an allowance at the next review for differences between projected and actual costs, including an allowance for the financing cost of any additional investment required during the period. This approach may lead to cash flow issues, and could reduce the certainty that additional expenditure will be recognised at the subsequent reset. It could also result in a substantial price-shock; or

[33] It should be noted that the ODRC for a new asset is its efficient cost at that point in time. EnergyAustralia expects that this is the value that the ACCC will allow to be included in the RAB as arising out of EnergyAustralia's capital expenditure program.

(d) Allow a pass-through of the cost of certain defined events during the regulatory period, if such events occur. This would be subject to an appropriate review mechanism.

The fourth approach represents a 'pass-through mechanism' and has precedents in many jurisdictions and has been utilised by the ACCC in previous determinations. It has the advantage of providing certainty, to both the business and the regulator, of the process that will be followed if there are unexpected changes in costs.

EnergyAustralia recognises the need to clearly and closely define those costs that will be allowed to be passed through so as not to undermine the general incentive properties of the CPI-X regime.

In the following section EnergyAustralia identifies several categories of events that we believe should trigger an application for a cost pass-through during the next regulatory period for our transmission business. With assistance from NERA, who provided a report as part of EnergyAustralia's submission to IPART, we set out our preferred process for making an application for a pass-through amount, and also set out a mechanism whereby approved pass through amounts would be translated into tariff charges. EnergyAustralia's proposed "Pass-Through Rules" are provided as Attachment 13.

Events that trigger a pass through

EnergyAustralia believes there are three main categories of events that have the potential to cause material changes to costs and that should be granted pass-through status. These are:

- Cost changes which are the result of changes in statutory requirements;
- Cost changes due to unexpected or very rare and easily identifiable events; and
- Cost changes due to significant changes in (non-statutory) cost drivers.

Changes in statutory requirements

EnergyAustralia must comply with a large number of statutory obligations and regulations which directly impact on the costs of operating the network. These regulations include environmental standards, work safety obligations, license requirements and compliance with taxation laws, which all have direct and indirect impacts on operational costs. Changes to regulations that are foreseen at the time that the revenue determination can be built into forecast costs. However, in some cases, changes to the policies of external regulators are not foreseen and often have significant impacts on EnergyAustralia's obligations. Several relevant examples are listed below:

- Recent WorkCover regulations have significantly increased the costs of working within confined spaces. This has implications for the distribution network predominantly, however, jointing of transmission cables is affected by the new requirements. The WorkCover requirements came into effect in 2003 and have therefore been included in forecast transmission operating and maintenance costs for the next regulatory period.
- EnergyAustralia currently enjoys an exemption from WorkCover's regulations relating to 'live wire' work. WorkCover's revocation of our exemption would significantly increase network maintenance costs for both transmission and distribution. As at the time of preparation of this submission, discussions surrounding the continuation of the exemption are occurring with WorkCover, however, there has not been any formal decision to change the current arrangements.
- EnergyAustralia has alerted the Environmental Protection Authority (EPA) to the fact that many of our 132kV cables are oil-filled and are reaching the end of their useful lives and consequently have an increased risk of oil leaks which could potentially result in environmental contamination. EnergyAustralia has a program of replacement for these assets (which has been agreed to by EPA). However, should the EPA tighten the regulations further and require faster replacement than that incorporated in the capital expenditure program, EnergyAustralia would be faced with significantly increased costs for the transmission business.

In all of these cases, EnergyAustralia has no ability to control the regulatory changes and the associated cost implications. EnergyAustralia believes it is therefore prudent to include compliance with new regulatory requirements as a pass through event where the cost impacts are material.

Change in unforeseen or very rare events

Unforseen or very rare events by their nature do not occur often and usually are outside of the control of the network business. In many cases, a business can insure for events that are outside its control or take steps to minimise the impact of an event on its business through self-insurance. EnergyAustralia self-insures for bushfire damage and has a program of fire risk mitigation which we believe reduces the material impact of fires on the network as much as possible.

There are some events that are so rare or unforseen that a prudent business would not insure against such events. To do so would unnecessarily increase the operational costs of the business and raise prices. However, there are a range of events that could potentially occur which could dramatically impact the business and where it would be prudent to these additional costs through.

An example of such an event could be a terrorist attack on electricity infrastructure that caused a shut down of supply to the CBD. This would have significant cost implications for EnergyAustralia and would include not only the costs of replacing damaged assets but also the costs of lost revenue and any financial penalties incurred due to an inability to meet service obligations. EnergyAustralia is not able to insure against terrorist attack as insurance is not available. Even if insurance were available, it is likely that taking out such insurance would not be cost effective and would increase prices unnecessarily where such an event did not occur within the regulatory period.

EnergyAustralia believes it is appropriate to allow a pass through of costs for rare or unforeseen events. This is a superior option to building in implicit premiums into prices to cover events which may or may not occur within the period.

Change in external cost drivers

The costs of regulated businesses can be effected by several factors. The regulatory framework relies on forecasts of these costs that in turn rely on assumptions for inflation and other factors in order to predict how costs will change over the period. There will always be differences between actual and forecast costs over the five year period, but where difference occur due to events that are included in an actuarially fair distribution of events, the risk of cost changes is systematic to the framework and therefore not unforeseen.

Where a material change in costs occurs that is brought about by an event that was not considered in the development of benchmark costs, it is efficient for these costs to be passed through. A recent example is the impact that the events of September 11, 2001 that have increased insurance premiums and in several cases doubled premiums.

EnergyAustralia believes that changes to costs as a result of external events should be able to be passed through where the impact of the event on costs is material. A potential example of where EnergyAustralia may seek a pass through of costs in the next regulatory period under this category is where the costs of easements jumps significantly due to rezoning of land by council.

Precedents for pass through

We note that the ACCC has previously approved pass through mechanisms for TNSP's in other jurisdictions, and that several other jurisdictional regulators including the ESC in Victoria and the ESC of South Australia have adopted cost pass through provisions that allow for the pass-through of similar types of unexpected costs. Allowing the business to pass-through these costs into prices if and when the change occurs is preferable to attempting to include an amount in the expenditures to cover potential costs changes, or to allow the business a higher WACC to compensate it for the additional risk it faces. Both of the latter options result in prices being higher during the regulatory period, whether or not the change actually occurs. In contrast, dealing with these cost changes through a pass-through mechanism will mean that prices are only affected if and when, the change eventuates.

As noted above, EnergyAustralia recommends that a pass-through mechanism be incorporated during the next regulatory period. Our proposed rules for making and considering a pass through application is included in Attachment 13.

Self-insurance

As noted above, EnergyAustralia faces significant risks in the conduct of its business that are not covered in its operating costs or compensated through the WACC. In many cases, these risks cannot be insured cost-effectively, if at all. EnergyAustralia bears and manages these risks internally and should be compensated for these costs.

EnergyAustralia engaged Trowbridge Deloitte to review and quantify the costs of internally borne risks. This review identified the most significant non-insured risks faced by EnergyAustralia and calculated an amount deemed by Trowbridge Deloitte as being actuarially fair compensation for bearing these risks. These risks fall into the following categories:

- Property related risks
- Currently insured risks
- Credit risks, and
- Other risks

As provided in Appendix 12, Trowbridge Deloitte identified risks totalling $0.44 million per annum for EnergyAustralia's transmission business. EnergyAustralia notes that the total annual costs associated with self-insured risks for EnergyAustralia's network businesses has been identified in the Trowbridge Deloitte report to be $6.02 million, the majority of which ($5.58 million) relates to EnergyAustralia's distribution business[34]. Therefore, EnergyAustralia seeks an amount of $0.44 million to be included in calculations of its required operating expenditures for its transmission business per annum as outlined in Chapter C.

The full report received from Trowbridge Deloitte is included in Appendix 12.

EnergyAustralia notes that in 2002, the ACCC allowed SPI Powernet to claim a self-insurance premium provided that it met certain conditions (including that the premium had been calculated on an actuarial basis).

8. Commercial Return on Capital

Weighted Average Cost of Capital ("WACC")

This section sets out the regulated rate of return that EnergyAustralia requires on efficient capital investment.

The cost of capital can be defined as an opportunity cost (or as the return on the average regulatory asset base) that is required from investments - having adjusted for risk differences between investments - before an investor acting commercially would commit capital. Aligning the rate of return to the cost of capital is the primary determinant of a company's financial viability and is an essential criterion as to whether further investment should take place.

In setting the return on capital, the ACCC should strive to put in place principles that will reduce:

- regulatory uncertainty;

[34] EnergyAustralia has also raised the issue of self-insurance costs for its distribution business in the 10 April 2003 submission to IPART on the 2004 Distribution Determination.

- risk to the investor; and hence
- the underlying costs faced by customers in the medium to long term.

The importance of WACC cannot be overstated in the context of a pricing review since, as noted by the ACCC[35]:

> *"…relatively small changes to the rate of return can have a significant impact on the total revenue requirement, and ultimately end user prices."*

The risks of a regulator erring by setting an inappropriate return on capital are not symmetrical. The consequences of setting a return too low are far more severe than setting one too high.

This has also been acknowledged by the ACCC[36]:

> "..the key adverse consequence of too low a value is considered to be the possibility that the service provider will not have the incentive to invest in new capital when it is required with ensuing consequences for the integrity of the system and the plight of users wishing to expand their usage of gas. Such circumstances are unlikely to be compensated for by slightly lower tariffs for all users. By contrast, the consequences of a slightly higher WACC are considered relatively minor."

Further, setting the return on capital at too low a level particularly penalises infrastructure asset owners, who cannot easily redeploy assets to alternative uses.

A similar view was expressed in submissions to the Productivity Commission Review of the National Access Regime, where the point was made that:

> *" there is an asymmetry in the consequences of over- and undercompensating investors in essential infrastructure facilities. Regulators effectively face a choice between:*
>
> - *Erring on the side of lower access prices, presumably so as to ensure the removal of any potential for monopoly rents and of the consequent allocative inefficiencies, from the system; or*
> - *Allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent productive and dynamic efficiencies such investment engenders.*
>
> *The dynamic and productive efficiency costs associated with distorted investment incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing.*
>
> *The Commission accepted these important points."* [37]

The assessment of an adequate rate of return is of critical importance to EnergyAustralia. Regulated rates of return in recent regulatory decisions have been inadequate to provide the necessary incentives for private investment in the network. This is particularly the case in light of actual rates of return being earned by regulated businesses often falling well below forecast returns in regulatory decisions generally due to unachievable assumptions of future expenditure.

Failure to provide an adequate return to investors will deny customers the economic benefits of additional prudent investment, as discretionary investments are unlikely to be economically justifiable. An inadequate rate of return will result in the necessity for EnergyAustralia to critically review its proposed investment program.

As noted throughout this submission, EnergyAustralia is unique in that it is subject to a complex regulatory arrangement whereby our electricity network assets are regulated by two

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[35] ACCC Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999. Page 71.

[36] ACCC Victorian Gas Transmission Access Arrangements Draft Decision, 28 May 1998. Page 61.

[37] Productivity Commission's Position Paper on the Review of the National Access Regime, 29 March 2001.

jurisdictional economic regulators (ACCC and IPART). To the extent that the ACCC and IPART adopt different approaches, and indeed final positions, on the allowed rate of return on capital, the same network asset may be subject to different rates of return depending on whether it is a transmission or distribution asset according to the Code definition. EnergyAustralia notes that the movement of assets will continue to occur as long as the current Code definition is in place and our network business continues to be regulated by two jurisdictional regulators.

To the extent practicable, and recognising the differences in the stated approaches of the two economic regulators on specific WACC parameters and modelling approaches (ie., the regulatory treatment of tax depreciation), EnergyAustralia has provided a recommended rate of return on its transmission assets that aligns closely with the recommendations made to IPART for distribution assets.

We believe that the ACCC should also consider the specific circumstances of EnergyAustralia's network assets and the regulatory framework we face when forming its views on the appropriate rate of return. This is particularly the case given that EnergyAustralia's transmission assets are generally more "distribution" in nature than the other "pure" transmission companies that the ACCC regulates.

Code Requirements

Clause 6.2.2(b)(2) of the National Electricity Code requires the ACCC to set a fair and reasonable rate of return as one of the objectives of its economic regulation of TNSP's.

The Code provides further guidance to the ACCC in setting a revenue cap to be applied to a TNSP, in that it must take into account the revenue requirements of the TNSP having regard for (among other things) the *weighted average cost of capital* ("WACC") of the TNSP.

One of the key components in calculating the WACC relates to the calculation of the return on equity. The Code [38]states that:

> "There is a variety of methods which can be applied to estimate the cost of equity capital of a business enterprise. The Capital Asset Pricing Model (CAPM) remains the most widely accepted tool applied in practice to estimate the cost of equity."

While there are numerous approaches to calculating the return on equity, EnergyAustralia is supportive of the use of the CAPM as we do not believe there is a more appropriate alternative at this time.

The issue of whether a pre- or post-tax framework is most appropriate was canvassed by IPART in its Issues Paper DP56. EnergyAustralia, in its response to that paper, stated that in the absence a commitment by IPART to model tax liabilities over the remaining asset life and to apply an annuity based approach to the recognition of such liabilities, EnergyAustralia supports the Tribunal's pre-tax approach to calculating the WACC. Therefore, in our recent submission to IPART on distribution prices, EnergyAustralia adopted the use of a pre-tax framework.

EnergyAustralia notes, however, the ACCC's stated preference for a post tax framework and its willingness to model tax liabilities over the remaining asset lives, that has been adopted in recent transmission Decisions. For the purposes of EnergyAustralia's transmission revenues for the 2004-09 regulatory period, EnergyAustralia supports the post-tax WACC framework based on modelling tax liabilities over the remaining asset lives.

Overall, EnergyAustralia proposes that the following parameters and outcomes be adopted by the ACCC in its consideration of the appropriate regulatory rate of return for EnergyAustralia's transmission assets:

[38] National Electricity Code, Schedule 6.1 (2.2.2).

Table 13 - WACC parameters for EnergyAustralia *<<Market rates TBC>>* >>

Parameter	*Proposed Value*
1. Parameter	
Risk free rate – nominal 10 year Commonwealth bond	5.55 per cent
Real risk free rate – indexed bonds	3.34 per cent
Inflation	2.14 per cent
Gearing (D/V)	60 per cent
Asset beta	0.425
Equity beta	1.06
Debt beta	0
Debt margin	1.475 per cent
Usage of tax imputation credits	0.50
Market risk premium	6.0 per cent
2. **Outcomes**	
Nominal pre tax cost of debt	7.03 per cent
Nominal post tax cost of equity	**11.89 per cent**
Nominal post tax WACC	6.95 per cent
Nominal pre tax WACC	9.77 per cent
Real pre tax WACC	**7.47 per cent**
Nominal "Vanilla" WACC	**8.97 per cent**

Detailed matters relating to the individual parameters underpinning EnergyAustralia's recommended WACC are contained in Attachment 11 which has been prepared with the expert assistance of Network Economics Consulting Group (NECG).

9. Additional incentive framework issues

Return on working capital

At the time of the 1999 transmission determination, one important element of the investment framework was not addressed: the appropriateness for a return to be provided on the working capital employed in the efficient operations of a network business. The focus at the 1999 determination was clearly on the physical assets employed and the introduction of the transmission regulatory regime. EnergyAustralia believes that this important issue, however, now needs to be adequately addressed.

EnergyAustralia believes that the framework adopted by IPART for distribution pricing in NSW is a sound basis for approaching the issue of the return on working capital and has been in place now for several years. In essence the approach in NSW is based on the payment cycle having regard for the average trading terms of the businesses – in effect the amount of time that payments and receipts are outstanding. The total value of funds committed to maintaining these trading terms, the period of these terms and the WACC are used to subsequently derive the appropriate return on working capital on an annual basis.

EnergyAustralia recommends that section 5.3 of IPART's November 2002 Issues Paper (DP 58) titled "Regulatory Arrangements for the NSW Distribution Network Service Providers from 2004 to the ACCC for its considerations. Using this approach, consistent with its submission to IPART, EnergyAustralia's proposed return on working capital included is approximately $1 million per year throughout the 2004 to 2009 Determination period.

10. Capital expenditure recognition and treatment of IDC

In 1999, the ACCC took the view that the expenditure to construct new assets should be capitalised and included in the regulatory asset base in the year immediately following its commissioning date, with interest during construction (IDC) accruing on each asset. This decision was an attempt to align as closely as possible the pricing of new assets with the benefits generated by the additional assets. EnergyAustralia acknowledges that it worked with the Commission to ensure that the approach maintained the value of investments at the last Determination. However experience has now rendered this approach impractical.

The calculation of IDC is complex when the value of the IDC needs to be carried forward over regulatory periods. This occurs wherever the assets in question are constructed during two regulatory periods, and the capital expenditure in one regulatory period is not recognised until the subsequent regulatory period. EnergyAustralia faces this situation at the current time and has assets currently under construction that will be completed during the next regulatory period, and new projects which will be commenced during the next period but will not be complete until the next.

The present ACCC approach produces complications with both ODRC and roll-forward asset valuations. Under an ODRC valuation methodology, the accumulated IDC is held separate from the rest of the valuation and included as the last action, ensuring that unit rates do not distort any accumulated financing costs recognised by the ACCC and included in the IDC calculation. This situation could significantly damage the investment incentives where projects have long construction times.

Likewise, a roll-forward approach also faces complications from IDC as the timing of projects and inter-determination carry-overs need to be maintained and reported. This complicates the reporting process and results in total capital expenditure recognised in a period exceeding the actual expenditure made, as is likely to occur in the 2004 regulatory period.

In addition, the approach of specifically establishing a set of projects upon which to establish a forward looking revenue stream has shown to have limited application in a range of circumstances. This has been recognised by the ACCC in determinations made since 1999, with the acceptance of more probabilistic approaches to determining capital expenditure requirements for TNSP's.

A probabilistic approach cannot use make use of a commissioning date assumption for capital expenditure, as it is merely the result of the probable sets of cash flows associated with a range of possible outcomes. In this case the ACCC must, and EnergyAustralia believes the ACCC has, adopted an approach whereby the capital expenditure is recognised in the forward RAB calculations as spent, on a cash basis within its PTRM model.

This approach offers superior management incentives. It ensures that the regulator does not implicitly accept the particular projects that make up a TNSP's forecasts, but rather accepts that the level of expenditure is most likely to be prudent based on forecast data. Secondly, it provides management of the TNSP with the flexibility and incentive to manage the capital expenditure allowance as efficiently as possible and to consequently demonstrate its prudence and efficiency at the time of the next review. This is critical to ensure that management has the appropriate incentives to respond to the changing circumstances that arise during the regulatory period, without being bound to the specific projects that may have been forecast at the time of the original Determination.

EnergyAustralia submits that the ACCC should adopt an annual approach to the recognition of capex, with an allowance for the financing costs associated with expenditure during the year.

11. Efficiency carryover mechanism

Experiences with efficiency carryover mechanisms to date have shown that they are generally information intensive, and in order to provide balanced incentives, tend to become overly complicated with marginal observed benefits. It becomes an area of significant uncertainty and discretion as to how "efficiency" under such a mechanism is defined, and what is included / excluded from the calculation of the mechanism.

It would clearly be inappropriate to further penalise businesses in situations where higher than forecast expenditures are undertaken in response to changed circumstances (given that the revenue cap does not provide additional revenues for these expenditures, even if they are prudent and efficient under any test). This would occur if revenues are further reduced in subsequent periods depending on the treatment of the additional expenditures (even though they were deemed to be efficient) within the efficiency carryover mechanism's operation.

Given that the basic nature of the regulatory framework in terms of asset valuation may be revisited by the ACCC, we do not believe that an efficiency carryover mechanism - which we do not believe forms a core aspect of the regulatory framework - is appropriate to be considered at this time. If the ACCC were to consider introducing such a mechanism at some point in the future, we believe that a trial period needs to be undertaken to ensure that the expected outcomes of the framework would in fact be as intended. EnergyAustralia believes that it is far more problematic to introduce a mechanism that provides the wrong incentives than to not introduce one at all during the 2004 Determination period.

Accordingly, EnergyAustralia does not support an efficiency carryover mechanism at this time.

12. Merit Appeals

As stated in the COAG Energy Market Review Final Report[39] the Panel formed the view that:

> "Decisions of the [National Energy Regulator] would be appealable, either on merits review by the Australian Competition Tribunal or on judicial review grounds by the relevant court of appeal."

EnergyAustralia supports the Panel's recommendation for the establishment of a full merit appeal process and considers that one should apply to the 2004 Determination. One of the difficulties with the present regulatory regime is that there is neither a clear, nor a universal right to merit appeals. In some instances there are appeals, in others there are not, and in some circumstances there are limitations on what can be appealed.

EnergyAustralia believes that a full merit appeal process will have the benefit of creating an incentive for regulatory decision-making to be more accountable and transparent and should form an essential part of any regulatory regime.

13. Conclusions

In order to provide an effective investment framework, EnergyAustralia believes the following components should be reflected in the ACCC's regulatory regime:

- A regulatory period of sufficient length (i.e. five years) in order to provide an incentive to achieve efficiency gains which can then be shared between a business and its customers;
- Certainty that prudent and efficient investments (both past and future) will be recognised in the regulatory asset base (RAB) and will receive a regulatory return on and return of capital;
- Clarity as to what constitutes "prudent" investment on an *ex ante* basis (i.e. prior to the commitment of capital);
- Appropriate allocation of risks between the business and its customers and appropriate compensation for the risks borne by the business;
- Adoption of a "pass through" mechanism to create flexibility within a regulatory period to provide investment certainty when confronted with significant and unanticipated changes in circumstances;

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[39] Council of Australian Governments – Energy Market Review Final Report "*Towards a Truly National and Efficient Energy Market*". Page 88. See also Recommendation 2.11 on page 49.

- A commercial rate of return within each regulatory period; and
- A merit appeals mechanism being established to encourage regulatory decision-making to be more accountable and transparent.

E REVENUE REQUIREMENT & PRICE OUTCOMES

1. Revenue Requirement

Building Block Revenue

The revenue requirement is the minimum amount required for EnergyAustralia to operate its transmission business, in order to provide customers with prescribed transmission services.

The revenue requirement outlined by EnergyAustralia supports appropriate service outcomes for our customers and the wider community and provides long term investment incentives for our business and our shareholder. It has been carefully developed in order to achieve appropriate levels of asset performance, while ensuring customers receive the benefit of our efficient operations. It also supports sufficient revenue to fund transmission operations. Taken together with the distribution revenue sought from IPART, it will repay debt, meet capital expenditure forecasts and contribute to an A-benchmark credit rating.

The building block revenue us based on the ODRC of transmission assets, as specified in the ACCC's Statement of Regulatory Principles. Sinclair Knight Mertz were commissioned by EnergyAustralia to review the asset value as at 1 July 2004, and a copy of their report is attached. Offsetting the ODRC value is the value of capital contributed assets associated with the undergrounding of transmission lines at the Homebush Olympic site.

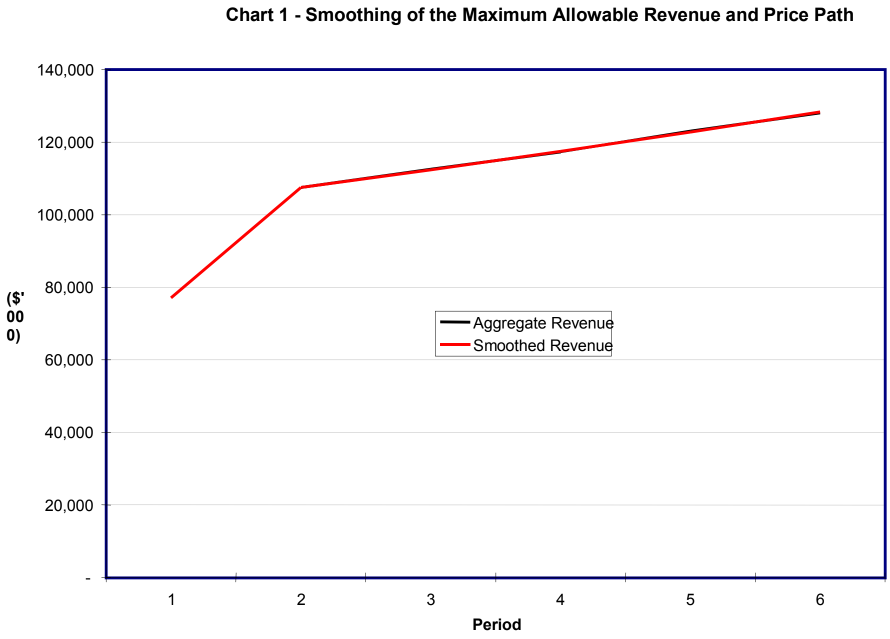
The annual revenue requirement has been constructed for the base case using a "building block" approach as is now adopted in most regulatory Determinations throughout Australia by adaptation of the model provided by the ACCC[40]. It is calculated as the sum of the cost components that contribute to the cost of providing the service. These are:

- the required **operating and maintenance expenditure**;
- the **return of capital**, which is the annual depreciation charge on the assets;
- the required **return on capital**, which is the product of the required rate of return on capital and the average regulatory asset base and working capital; and
- the **taxation payable less imputation credits**.

The forecast for each of these components for the base case is provided below:

[40] PTRM Electricity.xls, ACCC, 6 June 2003.

Figure 13 - Revenue Requirement (nominal)[41]



It should be noted that the apparent significant revenue change (from $77 M to $108 M) arises principally due to the inclusion of additional assets in the transmission asset base. This has been caused by two factors: the construction of assets that were not envisaged at the time of the 1999 Determination; and the creation of a parallel path with additional assets between Tuggerah and the Sydney area (which would be removed from the distribution asset base).[42]

To put this apparent price change into perspective, if the expected closing asset base at the start of the last Determination of $457.4M is substituted into the model for the opening asset base of $702M, the revenue requirement in the first year of the Determination would become $77 M, similar to the present allowable revenue.

The components of the opening asset value change are outlined in Table 14.

[41] Working Capital (WC) is very small in comparison to the other blocks and therefore is difficult to see on this graph.

[42] Identification of these assets and explanations of why these assets have been added to EnergyAustralia's transmission assets can be found in Appendix 2.

Table 14 - Components of the opening asset value

Category	Contribution ($m)	% 2004 valuation
1998 Valuation – ACCC determination	457.4	64%
Asset reclassified as transmission	18.8	3%
Additional transmission assets	116.3	16%
Cable tunnels	14.7	2%
Additional network IT and control systems	23.1	3%
Additional non system assets	17.1	2%
Change in work in progress allocation	17.5	2%
Contribution due to changes in asset unit rates	55.4	8%
2004 Valuation	**720.3**	100%
Less capital contribution	(18.2)	
TOTAL	**702.1**	

The following chart and table provides the key elements that have been incorporated in to the proposed distribution revenue requirement in real terms.

Figure 14 - Building block components

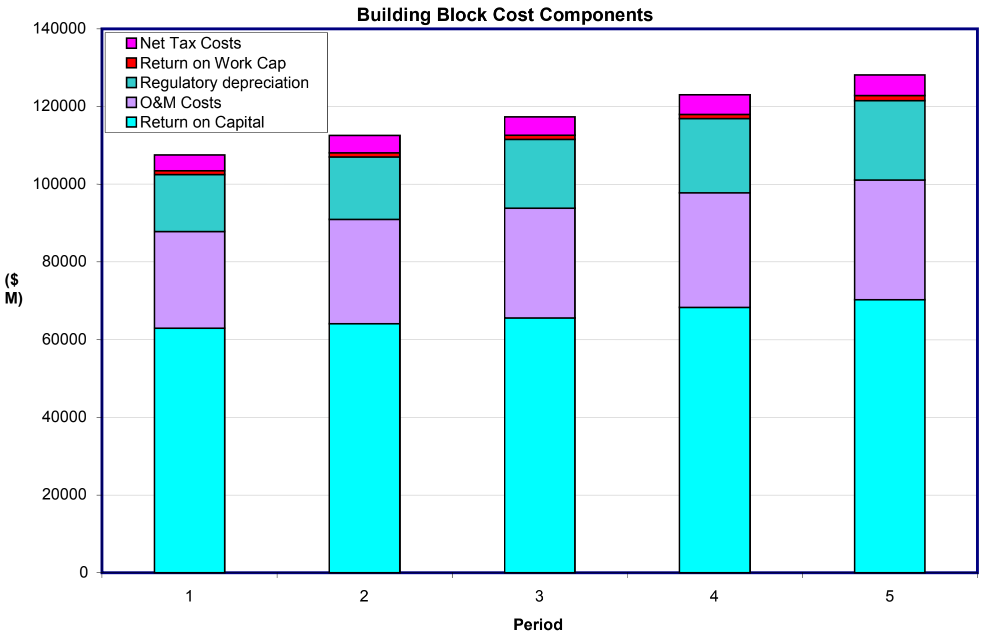


Table 15 - Components of the proposed transmission revenue requirement (nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09
Operating and maintenance	24,891	26,864	28,300	29,541	30,823
Return of capital	14,591	16,001	17,730	19,085	20,485
Return on capital	62,981	64,140	65,605	68,301	70,270
Return on Working Capital	1,062	1,078	1,019	1,133	1,252
Taxation less credits	4,022	4,475	4,726	4,993	5,334
Base Revenue Requirement	107,547	112,559	117,380	123,053	128,166

Revenue Smoothing

The above section described how the revenue requirement for the 2004-2009 period has been built up using the "building block" approach. This required revenue then needs to be translated into a regulatory cap. This approach has been accommodated within the ACCC's model.

This approach is strongly supported by EnergyAustralia as it provides prices which match network costs. The "P_0" adjustment effectively realigns prices at the start of the regulatory period to ensure that the outcomes from the Determination can be achieved through cost reflective pricing and the associated signals to customers to manage demand. Furthermore, it does not continue any legacies from the preceding period that would impact on the intended economic signals moving forward.

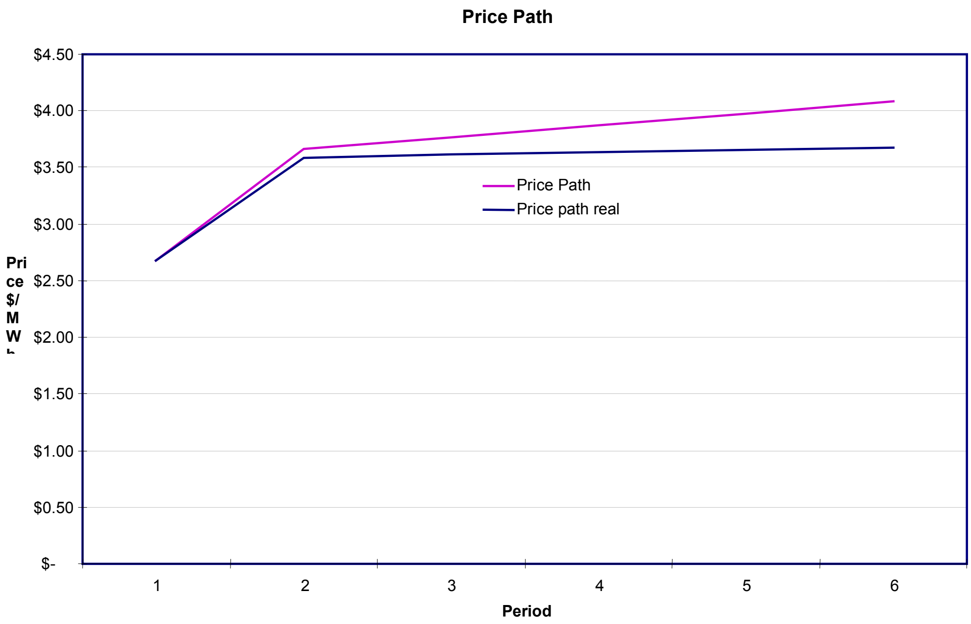
2. Average Pricing Impact

As noted above, customers pay for the use of the distribution network through prices that convert the proposed revenue requirement into actual network charges. On an *ex ante* basis, the average network price recovers the revenue requirement (no more, no less) as all forecasts impacting on revenue are necessarily assumed to hold true over the period. This will, in fact, only be true if side constraints do not limit the ability to recover the average prices and if the "profile" of the pricing trajectory allows the business to recover the NPV of the required revenue over the period.

The structure of individual prices is important to signal to customers the impacts of their use of the network. This is discussed in detail in the following section.

However, the average impact of the proposed revenue requirement on customers can be demonstrated by examining the average network price movement over successive regulatory periods as illustrated in Figure 15.

Figure 15 - Average EnergyAustralia transmission price trajectory



In constant dollar terms, EnergyAustralia's proposed revenue requirement results in real average network price increases over current prices. However, EnergyAustralia is now in a position where higher levels of capital and operating expenditures are being undertaken.

A "P_0" adjustment is required in 2004, followed by prices that are approximately constant in real terms over the remainder of the regulatory period. As stated above, the major part of the P_0 increase is associated with the inclusion of new assets and assets previously deemed distribution, in effect changing the boundary between transmission and distribution. The equivalent P_0 price change excluding these additional assets but including revaluation of existing assets would be approximately 6.8 per cent nominal or 4.6 per cent real.

A further aspect which should be noted concerning the proposed price change is that EnergyAustralia transmission represents only around 10 per cent of the total network cost and 5 per cent of delivered energy costs for small EnergyAustralia customers.

3. Limits on price movements

A 2 per cent limit to the movement of the Usage Charge for connection points to the transmission network is a requirement of Chapter 6.5.5 of the Code. EnergyAustralia has, and intends to continue to abide by that requirement when recalculating its transmission prices in the period of the new Determination.

IPART has indicated that it is considering the application of a side constraint to overall network prices in NSW (ie. to transmission plus distribution charges). This side constraint is in addition to the Weighted Average Price Cap regulatory control formula, which restricts the movement of distribution prices.

This overall side constraint may well determine the price path in the next ACCC Determination, as it has during the current one. IPART would then effectively determine the transmission prices passed through to customers, thereby preventing the cost signals inherent in those prices from being passed through to customers. It is also possible that this overall side constraint would conflict with the Code provisions.

Whilst these arguments have been put to IPART in EnergyAustralia's distribution network submission, it is important that the ACCC be aware of the implications of IPART's proposal.

4. Pricing Initiatives

EnergyAustralia is conscious of the need for network prices to reflect the costs of supply, which is consistent with its Demand Management initiatives aimed at reducing capital expenditure on the network. For the great majority of customers, the transmission price represents a small component (less than 20 per cent) of the total network charge. Consequently, the major focus of EnergyAustralia's pricing initiatives has been at the distribution level, targeted at delivering benefits to both transmission and distribution networks.

Changing consumption patterns

Over the past several years, the consumption and peak demand of EnergyAustralia's customers has changed significantly. Not only has consumption increased overall, the profile of when consumption is occurring and the duration of daily peaks has also changed. This has serious implications for the capital expenditure required to keep network performance within acceptable limits. It also affects the way EnergyAustralia sets its tariff structure to deliver appropriate economic pricing signals.

EnergyAustralia has reviewed its tariff structure to ensure that it better signals the costs of providing distribution services to each customer class. This is based on each class's impact on the costs of the network.

The changing patterns of network utilisation have made the pricing time bands that have been used for many years no longer suitable. The morning peak has not been as pronounced in the last two or three years. The afternoon demand has become more prominent, particularly in summer, and the evening peak lasts longer and is higher. The increased use of air conditioning by small business and domestic customers has had a significant impact on the summer "afternoon demand". EnergyAustralia's Price and Service Report outlines the new time bands, which were fully implemented in FY02.

Transmission price structure

EnergyAustralia proposes to retain a transmission price based upon Time of Use energy during the period of the new Determination. The Usage component of the charge is recovered during peak and shoulder periods, with a weighting towards peak period consumption. The other TUoS components of the charge are recovered at the customer level through anytime energy or fixed components. During the course of the current determination, the duration of the peak period was redefined to include summer afternoon periods and so better reflect the network constraint periods.

There are 10 direct customer connections to EnergyAustralia's transmission network. With the exception of one, which has a price separately determined by the ACCC, the transmission price structure is directly reflected in their network prices.

For customers connected to the distribution network, the TUoS charge is passed through as directly as possible. The way in which the price is structured depends primarily upon the capability of the metering at the customer premises.

Distribution price structure

EnergyAustralia's distribution pricing proposals reflect the findings of the COAG Energy Market Review and IPART's Report into Demand Management. EnergyAustralia has several major outcomes that its distribution pricing proposals are designed to achieve and has struck a balance to deliver the following outcomes:

- to recover the total costs of delivering network services;
- to undertake prudent and efficient non-network augmentation solutions;
- to manage peak demand; and
- to enable customers to better manage their consumption.

EnergyAustralia has worked to ensure that pricing goals of equity and simplicity are maintained while pursuing the pricing objectives above.

EnergyAustralia proposes a strategy to introduce price signals that will support an increased role for Demand Management in the market, as price is a key barrier to Demand Management participation and propose to:

1. Implement mandatory pricing on a time of use basis for customers above 15MWh. This would be supported by a roll out of interval meters to approximately 85,000 customers and would also introduce voluntary time of use pricing for smaller customers;

2. Introduce “inverted” block pricing for domestic and small business customers with single rate meters;

3. Develop a seasonal pricing component in the form of a summer surcharge for time of use customers;

4. Further develop interruptible and load control tariffs to allow demand-side influence on peaks;

5. Increase the capacity-driven component of prices for medium size customers; and

6. New infrastructure charges to apply to new and upgraded three phase or large installations that reflect a user-pays principle for the cost of providing capacity demanded with very poor load utilisation.

Further detail of these network pricing initiatives and their integration into a coherent Demand Management strategy is included in EnergyAustralia’s submission to IPART.

F SERVICE STANDARDS

EnergyAustralia's transmission network is different to most regional transmission networks as it does not provide interconnector services between NEM jurisdictions, nor does it operate to transfer electricity to other DNSPs in NSW. EnergyAustralia's transmission network provides support to TransGrid's network but it exists largely to distribute electricity to EnergyAustralia's distribution network.

Service standards as they relate to transmission networks are different from those that relate to distribution networks. In our submission to IPART, EnergyAustralia put forward a number of customer service outcomes that could be achieved through varying capital programs. In that submission, EnergyAustralia called for serious consideration to be given to the willingness of EnergyAustralia's customers to pay more for improved service standards at the distribution level. This matter is currently under consideration by IPART.

Standards of service are usually much higher in transmission than in distribution due to the number of lines measured in the calculations and the likelihood of those lines to be impacted by severe weather or the actions of third parties. Furthermore, there is less tolerance for interruption of transmission services, which impacts on the construction specifications for transmission assets.

To date, transmission service standards have been measured and reported to the ACCC on an annual basis. Reporting has been for information purposes and to date has not been linked to financial outcomes.

ACCC Service Standard Guidelines

The ACCC has recently released its draft decision relating to Service Standard Guidelines, which will be applied to the revenue cap for each TNSP. The purpose of introducing Service Standard Guidelines is to ensure a consistent approach across TNSPs and to address the perverse incentive that TNSPs may have to maximise profits at the expense of service standards.

EnergyAustralia supports the ACCC's stated intention to link each TNSP's revenue stream to performance or service standards and believes that TNSPs should be rewarded when performance standards increase and be penalised only when performance standards decline. EnergyAustralia supports the proposed penalty/reward level of one percent of revenue.

The ACCC's draft decision proposes to apply the measures of Transmission Circuit Availability and Average Outage Duration to EnergyAustralia. Due to the significant differences in the type of network operated by EnergyAustralia and those operated by other TNSPs, it is not appropriate to apply the other service standard measures identified to EnergyAustralia.

In identifying the service standard measures, the ACCC and its consultant, SKM, have based the targets on historical information. EnergyAustralia supports SKM's view that an incentive mechanism should not be implemented until there is sufficient data to establish the right benchmarks for service standards. Furthermore, EnergyAustralia believes that it is not appropriate to apply industry wide benchmarks to set service targets because of the substantial differences between the networks of the different TNSPs and the diversity and complexity of their operating environments. EnergyAustralia believes that targets should be set based on five years of data before financial consequences are activated.

Availability

EnergyAustralia believes that Transmission Circuit Availability is an appropriate measure of network performance for its transmission network. EnergyAustralia has collected data on availability since 2000/01. However, the data collected relates to transmission lines only and does not include other plant such as transformers or reactive plant. The information collected by EnergyAustralia has been used in establishing a proposed target of 95.5 minutes in the ACCC's draft decision. EnergyAustralia is concerned that this target appears to have been based on a single year's data (2000/01) and that the proposed target of 95.5 minutes will be made invalid due to:

- the inclusion of transformers and reactive plant in accordance with the proposed service standards definition; and

- the inclusion of significant lengths of new 132kV lines resulting from the re-classification of assets from distribution to transmission within EnergyAustralia's network.[43]

To ensure that an appropriate target is set, EnergyAustralia proposes that the target for circuit availability be based on at least three years of data collected on the basis of the standard definition. In other words, three years worth of data should be collected before targets for availability are set. EnergyAustralia proposes that the relevant target be negotiated mid-way through the 2004-09 determination period after three years of pertinent data is collected.

As a further concern, EnergyAustralia is mindful that an availability measure is likely to be significantly effected by capital works programs planned for the next determination period. EnergyAustralia agrees that the effect of a single event can be capped. However, this issue should be considered when determining an appropriate deadband within which there is no financial benefit or penalty applied. Like the target itself, EnergyAustralia believes that the extent of an appropriate deadband can only be determined once pertinent data has been collected.

Outage Duration

The second performance measure put forward for EnergyAustralia is Outage Duration. No target was set for this measure in the draft decision but it is noted in an appendix to that draft decision, that no target was set due to the volatility of the data available and the limited ability EnergyAustralia has to control such events.

EnergyAustralia is concerned that outage duration (restoration of equipment to service) is not an appropriate measure of performance due to several factors that are listed below:

- Average restoration period will not impact on EnergyAustralia's customers because of the inherent security of the network (use of double circuits etc).

- The repair times for assets such as underground cables can be significant (weeks or months) and can vary substantially depending on the type of cable. EnergyAustralia has a large proportion of underground cables in its network and is not able to easily control the incidence of outages on underground cables through changes to operational and maintenance programs. Incidences on underground cable can be impacted by a change in the type of cable used – replacing a pressure type cable to a solid dielectric cable. However, a choice to change the type of cable through new installations or replacement would be part of a major capital works program which EnergyAustralia believes is outside the scope of a performance standard incentive mechanism.

- The long duration of repair times could introduce significant volatility in the measurement of outage duration from year to year (i.e. a single incident could dramatically change the performance measure).

EnergyAustralia believes that due to the factors above, outage duration should not be used as a performance measure for EnergyAustralia during the next regulatory period.

Should the ACCC insist on a second measure, EnergyAustralia believes it would be appropriate for at least five years of data to be collected and analysed over the next five years to allow an informed investigation into how this measure could be equitably applied to EnergyAustralia.

[43] See Attachment 2 for further detail about distribution assets that will change classification to become transmission assets in 2004.

Other issues

EnergyAustralia made a submission to the ACCC in relation to its draft decision on service standards guidelines which is included as Attachment 10 to this submission. It includes further comment on specific issues included in the ACCC's proposed guideline.

LIST OF ATTACHMENTS

Attachment 1

Schematic representation of EnergyAustralia's Transmission Assets

Attachment 2

Moving Assets - Distribution Assets that will be classified as Transmission Assets as of 1 July 2004

Attachment 3

EnergyAustralia's Network Region Global Electricity and Customer Number Forecasts

2002-09

Attachment 4

Zone Substation Spatial Demand Forecasts

Attachment 5

SKM Report on EnergyAustralia's Forecast Operating Cost Program

Attachment 6

SKM Report Assessing Prudence of EnergyAustralia's Capital Expenditure Program for the 1999 Regulatory Period

Attachment 7

Reconciliation of Network Capital Expenditure – Regulatory Period 1 February 2000 – 30 June 2004

Attachment 8

Capital Governance Framework – Process Overview

Attachment 9

SKM ODRC Report on EnergyAustralia Assets as at 2004

Attachment 10

EnergyAustralia's Service Standards

Attachment 11

NECG Report on the Weighted Average Cost of Capital

Attachment 12

Trowbridge Report on Non-insured Risks Borne by EnergyAustralia

Attachment 13

EnergyAustralia's Proposed Pass-Through Rules

Attachment 14

EnergyAustralia's Proposed Treatment of Capital Contributions

GLOSSARY

ACCC	Australian Competition and Consumer Commission
AESDR	Annual Electricity System Development Review
ATO	Australian Tax Office
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CCA	Current Cost Accounting
COAG	Council of Australian Governments
CPI	Consumer Price Index
DM	Demand Management
DM Code	Demand Management Code
DNSPs	Distribution Network Service Providers
DORC	Depreciated Optimised Replacement Cost
DRP	Draft Regulatory Principles
DuoS	Distribution Use of System
EA	EnergyAustralia
EPA	Environmental Protection Authority
ESC	Essential Services Commission
FMECA	Failure Modes Effects Criticality Analysis
HV	High Voltage
IDC	Interest During Construction
IPART	Independent Pricing and Regulatory Tribunal of NSW
Jurisdictional Regulators	Regulators in each state that regulate distribution under NEC
KW	Kilowatt (one kW = 1000 watts)
KWh	Kilowatt hour
LRMC	Long Run Marginal Cost
MRAM	Maintenance Requirement Analysis Manual
MW	Megawatt
MWh	Megawatt hour (one MWh = 1000 kWh)
NAC	Network Access Charge
NEC	National Electricity Code
NECG	Network Economics Consulting Group
NEMMCO	National Electricity Market Management Company
NERA	National Economic Research Associates
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NUoS	Network Use of System
ODV	Optimised Depreciated Value
ODRC	Optimised Depreciated Replacement Cost
OH&S	Occupational Health and Safety
O&M	Operating & Maintenance

Opex	Operating Expenditure
PDS	Prescribed Distribution Services
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RCM	Reliability Centred Maintenance
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SKM	Sinclair Knight Merz
SLUoS	Street Light Use of System
SOO	Statement of Opportunities
SWMS	Safe Work Method Statements
the Code	National Electricity Code or NEC
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System
TransGrid	NSW Transmission Network Service Provider
Trowbridge	Trowbridge Deloitte
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
“Energy40 ToU”	Time of Use price